**Q.** **McShane Evidence - Would Ms. McShane please file a copy of her evidence before the AUC in the 2009 General Cost of Capital proceeding which led to Decision 2009 – 216.**

A. Ms. McShane's direct and rebuttal evidence in that proceeding are provided in CA-NP-363 Attachment 1.pdf and CA-NP-363 Attachment 2.pdf respectively.

**Alberta Utilities Commission**
**2009 Generic Cost of Capital Proceeding**

**Testimony of Kathleen McShane**
**November 20, 2008**

**ALBERTA UTILITIES COMMISSION**
**2009 GENERIC COST OF CAPITAL PROCEEDING**
**Application No. 1578571 / Proceeding ID. 85**

ON BEHALF OF THE

**ATCO UTILITIES**

**(ATCO ELECTRIC LTD., ATCO GAS AND ATCO PIPELINES)**

Direct Testimony
of


**KATHLEEN C. McSHANE**

**FOSTER ASSOCIATES, INC.**


November 20, 2008

## TABLE OF CONTENTS


| | | Page No. |
|---|---|---|
| I. | INTRODUCTION AND CONCLUSIONS | 1 |
| II. | BACKGROUND | 4 |
| III. | FRAMEWORK FOR EVALUATION OF CAPITAL STRUCTURES AND ROES | 6 |
| | A. Relationship between Capital Structure and Return on Equity | 6 |
| | B. Principles for Capital Structure Determination | 8 |
| IV. | CONCEPT OF BENCHMARK RETURN ON EQUITY AND RELATIONSHIP TO CAPITAL STRUCTURE | 15 |
| V. | FACTORS TO CONSIDER IN DETERMINATION OF CAPITAL STRUCTURE | 16 |
| | A. Comparable Awards in Other Jurisdictions | 16 |
| | B. Interest Coverage Analysis | 21 |
| | C. Bond Rating Analysis | 27 |
| VI. | RETURNS FOR THE ATCO UTILITIES | 31 |
| | A. Summary of Benchmark Recommendations | 31 |
| | B. ATCO Electric | 32 |
| | C. ATCO Gas | 40 |
| | D. ATCO Pipelines | 45 |

Appendix A: Qualifications of Kathleen C. McShane

# I. INTRODUCTION AND CONCLUSIONS

My name is Kathleen C. McShane and my business address is 4550 Montgomery Avenue, Suite 350N, Bethesda, Maryland 20814. I am President of Foster Associates, Inc., an economic consulting firm. I hold a Masters in Business Administration with a concentration in Finance from the University of Florida (1980) and the Chartered Financial Analyst designation (1989).

I have testified on issues related to cost of capital and various ratemaking issues on behalf of local gas distribution utilities, pipelines, electric utilities and telephone companies in more than 190 proceedings in Canada and the U.S. My professional experience is provided in Appendix A.

I have been asked by the ATCO Utilities to:

1. Provide a framework for determining a reasonable utility capital structure for the ATCO Utilities;

2. Describe specific capital market factors which the Alberta Utilities Commission (AUC) should consider in approving capital structures for the ATCO Utilities;

3. Discuss changes in circumstances since the Generic Cost of Capital decision in 2004 that impact the appropriate capital structures for the ATCO Utilities; and

4. Assess the business and regulatory risks of the individual ATCO Utilities relative to a utility sector-specific Alberta benchmark and determine the appropriate adjustments to its benchmark cost of capital for each of the ATCO Utilities.

In summary, my conclusions are as follows:

- With respect to the framework for determining a reasonable capital structure, the relationship between capital structure and return on equity must be properly recognized. Simply put, for a given utility, the higher the debt ratio, the higher is the cost of equity. The end result, the allowed overall return on utility investment, which includes the capital structure, the ROE and the cost of debt, must meet the fair return standard. Adherence to the fair return standard means the overall return on investment must permit the attraction of capital on reasonable terms and conditions, be sufficient to preserve the utility's financial integrity and provide for comparable returns on both existing and new investment.

- In evaluating the proposed capital structures, the key principles that must be respected are:
  - ➢ The Stand-Alone Principle.
  - ➢ Compatibility of Capital Structure with Business Risks.
  - ➢ Maintenance of Creditworthiness/Financial Integrity.
  - ➢ Comparability of Returns

- A reasonable capital structure in conjunction with a fair ROE should provide for debt ratings in the A category.

- Specific factors which point to increases in the common equity ratios for Alberta utilities generally and the ATCO Utilities specifically include:
  - ➢ Increases in allowed common equity ratios for other Canadian utilities since the Generic Cost of Capital decision;
  - ➢ Stronger capital structures and credit metrics of comparable U.S. utilities with whom the Alberta utilities compete for capital;
  - ➢ Factors which negatively impact credit metrics:
    - ▪ Lower income tax rates;
    - ▪ Switch from future to flow-through income taxes;

- Higher Capital Cost Allowance (CCA) rates; and
- High forecast level of capital expenditures.

➢ Concerns of capital market participants with respect to the levels of common equity ratios and ROEs for Canadian utilities.

• The table below summarizes my findings with respect to the appropriate ROE for the individual ATCO Utilities at the proposed common equity ratios.

**Table 1**

| | Business Risk Relative to the Sector-Specific Benchmark | Proposed Common Equity Ratio | Benchmark ROE at Proposed Common Equity Ratio | Recommended ROE at Proposed Common Equity Ratio |
|---|---|---|---|---|
| ATCO Electric Transmission | Similar | 38% | 10.5% | 10.5% |
| ATCO Electric Distribution | Similar | 40% | 10.6% | 10.6% |
| ATCO Gas | Similar | 40% | 11.0% | 11.0% |
| ATCO Pipelines | Higher | 43% | 10.9% | 12.0% |

## II. BACKGROUND

ATCO Utilities engaged Concentric Energy Advisors Inc. (Concentric) to estimate and recommend the cost of capital for a benchmark Alberta utility in each of the following sectors: electric transmission, electric distribution, natural gas distribution and natural gas transmission. The evidence of Mr. James Coyne of Concentric sets forth:

(1) The cost of equity ("ROE") for a benchmark Alberta utility in each of the four utility sectors;

(2) The actual capital structure at which the estimated ROE applies; and

(3) A range of capital structures which would be reasonable for a benchmark utility in each utility sector and the associated ROE.

Mr. Coyne's analysis is premised on the conclusion (with which I agree) that, within a reasonable range, the capital structure for a particular utility is appropriately a decision for management, because management is in the best position to assess its business risks, financing requirements and access to debt and equity capital. His analysis specifies the target capital structure range for a benchmark Alberta utility in each sector which (a) is consistent with the objective of minimizing the overall cost of capital; and (b) recognizes that there is a range of capital structures which is compatible with that objective and (c) will provide the utility with a reasonable level of financing flexibility. With respect to (b), within the identified range of capital structures, the overall cost of capital is relatively flat, i.e., an increase in the debt ratio, that is, an increase in financial risk, would effectively be offset by an increase in the cost of equity, so that the overall cost of capital does not change materially. With respect to (c), with a capital structure within the identified range, along with the corresponding ROE, a benchmark utility should be able to achieve credit metrics that would be consistent with debt ratings in the A category.

As long as the ATCO utility is comparable in business/regulatory risk to a benchmark Alberta utility, management should have the flexibility to target a capital structure within the relevant range. The corresponding ROE should then reflect the level of financial risk in the selected target capital structure. For example, if management chooses to target and maintain a common equity ratio at the lower end of the relevant range (higher financial risk), then the corresponding ROE would be higher than if it chooses a common equity ratio at the upper end of the relevant range.

I have been asked to assess the business and regulatory risks of the four ATCO Utilities (ATCO Electric Transmission, ATCO Electric Distribution, ATCO Gas and ATCO Pipelines) to determine whether there are factors which would lead to the conclusion that their overall cost of capital would differ materially from an average risk, or benchmark, Alberta utility operating in the same sector. If, on balance, the level of business and regulatory risks faced by the ATCO utility is not materially different from an average risk Alberta utility in its sector, the range of common equity ratios and ROEs estimated by Concentric would be applicable. In that case, management will propose a common equity ratio for the utility within the relevant range, and I will estimate the corresponding ROE for the combined level of business and financial risk. If, on the other hand, the level of the ATCO utility's business and regulatory risks are materially higher or lower than the benchmark, I will estimate the impact of the difference in risk on the particular ATCO utility's cost of capital and recommend how that difference should be incorporated into the appropriate common equity ratio and/or the ROE.

As indicated in Section I, I will also present a framework for the determination of capital structure, discuss capital market factors and changes since the last Generic Cost of Capital decision that the AUC should take into account when evaluating the ATCO Utilities' proposed common equity ratios (in conjunction with the ROEs).

## III. FRAMEWORK FOR EVALUATION OF CAPITAL STRUCTURES AND ROES

### A. Relationship between Capital Structure and Return on Equity

The overall cost of capital to a firm depends, in the first instance, on business risk. Business risk comprises the fundamental operating elements of the business that together determine the probability that future returns to investors will fall short of their expected and required returns. Business risk thus relates largely to the assets of the firm. For utilities, the business risks also include regulatory risks, i.e., the regulatory framework under which the utility operates. The prevailing regulatory framework effectively represents the current allocation of the fundamental business risks between investors and ratepayers. Business risk is a function of the fundamental characteristics of the operations, i.e., of the firm's assets. The cost of capital is also a function of financial risk. Financial risk refers to the additional risk that is borne by the equity shareholder because the firm is using fixed income securities – debt and preferred shares to finance a portion of its assets. The capital structure, comprised of debt, preferred shares and common equity, can be viewed as a summary measure of the financial risk of the firm. The use of debt in a firm's capital structure creates a class of investors whose claims on the cash flows of the firm take precedence over those of the equity holder. Since the issuance of debt carries unavoidable servicing costs which must be paid before the equity shareholder receives any return, the potential variability of the equity shareholder's return rises as more debt is added to the capital structure. Thus, as the debt ratio rises, the cost of equity rises.

There are effectively two approaches that can be used to determine the fair return. The first is to assess the utility's fundamental business and regulatory risks, then establish a capital structure that is compatible with those risks and permits the application of a benchmark cost of equity without any adjustment to the cost of equity determined by reference to proxy companies. This approach can be applied to a spectrum of regulated companies within a range of combined fundamental business and regulatory risks.

The second approach entails acceptance of the utility's actual capital structure for regulatory purposes or deeming a capital structure that adequately protects bondholders but does not necessarily equate the total (business, regulatory and financial) risk of the regulated company to those of the proxy or "benchmark" companies. The utility's level of total risk (business and regulatory risk plus the financial risks at the actual or deemed capital structure) is then compared to that faced by the proxy companies used to estimate the equity return requirement. If the total risk of the benchmark or proxy companies is higher or lower than that of the specific utility, an adjustment to the benchmark cost of equity would be required.

The National Energy Board (NEB) employed the first approach when it established its automatic adjustment mechanism for a number of oil and gas pipelines in 1995. The individual pipelines were deemed capital structure ratios that were intended to compensate for their different levels of business risks, so that a single benchmark return on equity could be applied across all of the pipelines. It is also the approach that was adopted by the former Alberta Energy and Utilities Board (EUB) in its Generic Cost of Capital Decision 2004-052 in 2004. In that decision, the EUB set different capital structures for eleven electric and gas distribution and transmission entities, based on their different business risk profiles, and then established a common return on equity to be applied to each of the utilities under its jurisdiction.

The second approach, that is varying both capital structures and ROEs, is also a valid approach as long as the total return, that is, the combination of actual/allowed capital structure and ROE for a particular utility reasonably compensates for its business risk relative to that of its peers. The British Columbia Utilities Commission (BCUC) has allowed for both different capital structures and different ROEs among the various utilities it regulates. However, it explicitly designates a low risk benchmark utility (Terasen Gas) and a low risk benchmark ROE. The allowed ROEs for the other BCUC utilities are expressed in relation to the low risk benchmark ROE, i.e., as an equity risk premium above the low risk benchmark ROE. The combination of capital structures and

ROEs is also used by the Ontario Energy Board (OEB) and the Régie de l'Énergie de Québec (Régie).

The ATCO Utilities are proposing the second approach, which varies both the capital structure and ROE. The proposed approach is not new for Alberta. In fact, it was the norm for the electric and gas distribution utilities throughout much of the history of regulation in the province. The use of the approach under which full compensation for business risk was incorporated into a deemed equity ratio was first adopted for the Alberta electric utilities during restructuring when capital structures by function (generation, transmission and distribution) were specified for vertically integrated utilities.[1] Prior to that, actual capital structures were used for the purpose of establishing the allowed return on rate base for both electric and gas utilities in Alberta.[2]

## B. Principles for Capital Structure Determination

The following principles should be respected when establishing the cost of capital generally and specifically for each of the ATCO Utilities:

1. The Stand-Alone Principle.
2. Compatibility of Capital Structure with Business Risks.
3. Maintenance of Creditworthiness/Financial Integrity.
4. Comparability of Returns

[1] In Decision U97065 (October 31, 1997), the EUB adopted a deemed equity ratio for the integrated operations of TransAlta, because the Board concluded that its actual equity component was too high for the level of business risk. In Decision U99099, November 25, 1999, the EUB adopted deemed equity components for the separate electric utility functions based on their relative risks and a deemed equity component for the integrated utility.

The concept of a deemed or hypothetical capital structure was initially adopted in Canada as a means of implementing the stand-alone principle. Adherence to the stand-alone principle means that only those costs, risks and benefits that arise from the provision of regulated service are borne by ratepayers. All other costs, risks and benefits incurred by the legal entity are to the account of the shareholder. The use of a deemed capital structure was intended to ensure that the cost of capital borne by ratepayers represented the stand-alone cost of capital of the regulated operations, not the cost of capital of the parent company whose operations and risks might be quite different from those of the regulated company.

[2] The second approach is applied to at least two NEB-regulated Group 1 gas pipelines, Alliance and Maritimes and Northeast.

Each of these principles is defined below.

### 1. The Stand-Alone Principle

The stand-alone principle encompasses the notion that the cost of capital incurred by each of the ATCO Utilities should be equivalent to that which would be faced if it was raising capital in the public markets on the strength of its own business and financial parameters; in other words, as if it were operating as an independent entity. The cost of capital for the company should reflect neither subsidies given to, nor taken from, other activities of the firm. Respect for the stand-alone principle is intended to promote efficient allocation of capital resources among the various activities of the firm.

### 2. Compatibility of Capital Structure with Business Risks

The capital structure of a utility should be consistent with the business and regulatory risks of the specific entity for which the capital structure is being set. The business risk of a utility is the risk of not earning a compensatory return on the invested capital and of a failure to recover the capital that has been invested. Business risk is a function of the fundamental characteristics of a utility (e.g., demand, supply and operating factors). Regulatory risk relates to the framework that determines how the fundamental risks are allocated between the utility's customers and its investors.[3] Changes in business risk are a relevant factor in assessing whether a change in capital structure should be made, but they are not the sole determinant.

[3] Regulatory risk can be considered either as a component of business risk or as a separate risk category along with business and financial risk.

### 3. Maintenance of Creditworthiness/Financial Integrity

A reasonable capital structure, in conjunction with the returns allowed on the various sources of capital, should provide the basis for stand-alone investment grade debt ratings in the A category. An A debt rating assures that the utility would be able to access the capital markets on reasonable terms and conditions during both robust and difficult, or weak, capital market conditions. In contrast to unregulated companies, utilities do not have the same flexibility to defer financing new assets. Utilities are required to provide service on demand, and must access the capital markets when service requirements demand it.

CU Inc. raises debt on behalf of each of the ATCO Utilities. CU Inc.'s debt is rated A(high) by DBRS and A by S&P. Debt raised by CU Inc. is mirrored down to the individual ATCO Utilities at the cost incurred by CU Inc. The ratepayers of each of the ATCO Utilities, therefore, receive the benefits of CU Inc.'s ratings. In turn, consistent with the stand alone principle, each of the ATCO Utilities should contribute its fair share toward the maintenance of the debt ratings through its own capital structure and ROE. It would be inequitable for customers to receive the benefits of debt costs that reflect an A(high)/A debt rating while the approved capital structure and ROE are only adequate for a BBB rating.

The critical nature of maintaining credit ratings in the A category arises from two factors: market access and cost. Even a utility with split-ratings (that is, one debt rating in the A category and one rating in BBB category) would face a higher cost of debt and lesser market access relative to a utility with all debt ratings in the A category. Regulated issuers with BBB ratings can be closed out of the market at times, particularly at the longer end (20-30 year term) of the debt market. The ATCO Utilities are principally financing long-term assets. Thus they need to maintain the financing flexibility required to be able to access debt with terms to maturity in the range of 10 to 30 years in all market conditions, particularly given their financing requirements (discussed below and in the evidence of ATCO Utilities).

If a utility experiences a downgrade, the downgrade would not only result in an increase in the cost of the additional debt that the company needs to raise, but it will affect all of the outstanding debt. An increase in the cost of debt to a utility increases the required yield on the outstanding debt and reduces the value of that debt. Since existing debt holders are the most likely purchasers of future issues, a debt rating downgrade, with the resulting negative impact on the value of their existing holdings, would likely make them less willing to purchase future issues.

A higher cost of debt to the utility translates into a higher cost of debt to ratepayers. The relative cost of A rated debt versus BBB rated debt varies with market conditions, but ratings in the BBB category can be very costly to ratepayers. As the recent global market crisis has demonstrated, capital markets can deteriorate rapidly.

A year ago (early November 2007), CU Inc. issued 30-year debt at a spread of 116 basis points over the benchmark long-term Government of Canada bond yield. The corresponding indicated spread for a new CU Inc. 10-year issue at the time was 85 basis points. At the beginning of November 2008, the estimated spreads for new CU Inc. 10-year and 30-year issues had risen to 270 and 300 basis points respectively, increases of 185 and 184 basis points. Spreads for companies with ratings in the BBB category have increased over the same period by an even greater amount, such that that the spread on new 30-year debt for a split-rated issuer like EPCOR Utilities is in excess of 400 basis points, as shown in the table below. The lack of an indicated 30-year new issue spread in November 2008 for TransAlta in that table signifies that TransAlta would not likely be able to raise 30-year debt at this time.

**Table 2**

| | Debt Ratings DBRS/Moody's/S&P | Term of Issue | Indicated Spread at 11/5/2007 | Indicated Spread at 11/4/2008 | Change in Indicated Spread |
|---|---|---|---|---|---|
| **CU Inc.** | A(high) / - / A | 10 yr | 85 | 270 | +185 |
| | | 30 yr | 118 | 300 | +182 |
| **Epcor Utilities** | A(low) / - / BBB+ | 10 yr | 120 | 355 | +235 |
| | | 30 yr | 175 | 415 | +240 |
| **Nova Scotia Power** | A(low) / Baa1 / BBB | 10 yr | 95 | 325 | +230 |
| | | 30 yr | 145 | 360 | +215 |
| **TransAlta** | BBB / Baa2 / BBB | 10 yr | 215 | 550 | +335 |
| | | 30 yr | 300 | N/A | N/A |

Source: RBC Capital Markets

This table underscores the potential magnitude of the incremental costs that are associated with being a BBB rated issuer, and the importance from both a cost and market access perspective of maintaining ratings in the A category. It bears noting that, in the case of a downgrade, the increased cost of debt would be borne by ratepayers over the full life of the issues. In light of the significant financing requirements of the ATCO Utilities in the medium term, the long-term impact on ratepayers of a higher cost of debt due to lower debt ratings would be significant.

In assessing the importance of maintaining strong A ratings, it is important to consider the relatively small size of the BBB market in Canada. As reported in "Back to Basics" by Marlene K. Puffer, *Canadian Investment Review*, Fall 2006, the BBB corporate debt market is only 4% of the total market and it is mainly limited to issues with terms under 10 years. Many institutional investors such as pension funds face limits on the proportion of BBB rated debt they are allowed to hold in their portfolios or cannot invest in BBB rated debt at all.[4] The small size of the Canadian market for BBB rated debt and

[4] The NEB reported in its August 2005 *Canadian HydroCarbon Transportation System Report* that Canadian bonds are an important revenue source to pension funds and other institutional investors, and a downgrade could require institutional holders to sell a large percentage of their bonds at discounted prices.

the limitations on the ability of BBB issuers to raise debt in the long-term end of the debt market underscore the importance of A credit ratings.

From January 2006 to October 2008, RBC Capital Markets[5] recorded $151 billion (417 issues) of corporate debt financing in Canada. Of that amount, companies all of whose ratings were in the BBB category or below accounted for 6% and 9% of the total dollar value and number of issues respectively. If companies with one rating in the A category (i.e., split-rated A/BBB category or lower) are included, those issues account for only 11% and 14% of the total value and number of issues respectively. From mid-2007 to October 2008, during which the credit markets have been experiencing various degrees of turmoil, of 154 reported issues, only five were by companies with all ratings in the BBB category or lower, none of which was for a term in excess of 10 years.

In its 2006 *World Energy Outlook*, the International Energy Agency estimated that between 2005 and 2030 close to $3.4 trillion in investment would be required by the gas transmission and distribution ($1.4 trillion) and electricity (close to $2 trillion, of which over $1 trillion is transmission and distribution) industries in North America.[6] The ATCO Utilities will be competing for capital in markets that may be characterized by an unprecedented requirement for regulated infrastructure capital. As utilities operating in an economy that is expected to grow much faster than the rest of Canada as a whole, and with significant infrastructure needs, the ATCO Utilities' capital expenditures and financing requirements are forecast to be much higher than average.

Between 2008 and 2011 (that is, within three years), the ATCO Utilities anticipate that the combined rate bases (net of customer contributions) of ATCO Electric, ATCO Gas and ATCO Pipelines will increase by 50% (over $2 billion), or close to 15% per year on average. To put this in some perspective, the average 2007 growth in net property, plant and equipment of non-Alberta utilities with rated debt was approximately 5%. Over the 2009 to 2011 period, the ratio of capital expenditures to net plant (net of

[5] RBC Capital Markets, *Credit Weekly*, various issues.
[6] Approximately $15 trillion world-wide.

contributions) for the ATCO Utilities is expected to average 15%, 50% higher than that of the 2006-2007 average of approximately 10% for non-Alberta utilities with rated debt.[7] The ATCO Utilities forecast that they will need approximately $1.5 billion in new long-term external capital over this period, or about $500 million per year on average, in capital markets that, given the current turmoil, may be difficult. By comparison, over the five-year period 2003-2007 (a period of relatively robust credit markets), CU Inc. was required to raise less than $300 million per year in new long-term debt and equity preferred shares to finance capital expenditures and refinance maturing debt.

To compete successfully for the required capital, that is, to continue to be able to attract capital on flexible terms and conditions, the ATCO Utilities will require financial metrics (which reflect the combination of capital structure and ROE) that are competitive with those of their peers. Competition for capital to address infrastructure investment requirements in North America (and globally) supports a strengthening of the ATCO Utilities' financial parameters, including their capital structures.

## 4. Comparability of Returns

The combination of the adopted capital structure and return on capital should be comparable to the returns adopted for comparable risk companies.

In order to be competitive in the capital markets, a regulated utility's financial parameters – which encompass both capital structure and ROE – need to be comparable to those of its peers. In this regard, it is important to recognize that the ATCO Utilities compete for capital not only with other Canadian regulated companies, but with regulated companies globally, as well as with unregulated companies. The achievement of comparability requires explicit recognition of the financial parameters of

[7] The average ratio for investor-owned non-Alberta utilities was somewhat lower, at approximately 8%.

the companies of comparable risk to the ATCO Utilities, which extend to regulated companies throughout North America.[8]

## IV. CONCEPT OF BENCHMARK RETURN ON EQUITY AND RELATIONSHIP TO CAPITAL STRUCTURE

The Concentric evidence develops a benchmark ROE for each utility sector in which the ATCO Utilities operate. The benchmark ROE does not refer to a specific utility and hence does not refer to a single utility's company-specific business/regulatory risks; rather it captures the composite of the business and regulatory risks faced by the proxy firms. It also captures the composite of the financial risks faced by the proxy samples of companies.

The applicability of the benchmark ROE of the different utility sectors to a specific utility thus is dependent on the business risks and the capital structure of that utility. As a general proposition, different utility sectors face different levels of business and regulatory risk. Utilities with combined lower (higher) business and regulatory risk would require lower (higher) common equity ratios to achieve a similar level of total (investment) risk. If the lower (higher) business and regulatory risks of a specific utility (within a sector) relative to the benchmark are completely compensated for, or offset, through a lower (higher) common equity ratio, the benchmark ROE can be applied directly to that utility, with no adjustment required. Alternatively, if the specific utility faces lower or higher business and regulatory risk relative to the sector benchmark, the

---

[8] The Conference Board of Canada has pointed out the importance of comparable returns for electric transmission in Canada. In its May 2004 Briefing entitled, "Electricity Restructuring: Opening Power Markets", the Conference Board stated,

> *"Investors are discouraged by limitations on the regulated cost recovery for transmission upgrading. Transmission companies are simply not seeing favourable risk/return ratios on their investments, and know that they can realize better returns in the United States, where regulated rates of return are much higher. Rates of return to Canadian firms for transmission projects are around 9 to 10 per cent, well below the 13 to 14 per cent available to U.S. companies. These lower rates discourage investment in Canadian utilities. Moreover, investors are additionally deterred by the fact that existing cost-of-service rates do not reflect the economic value of the transmission grid."*

lower or higher risk can be reflected in capital structure, ROE or a combination thereof. The objective is to ensure that the total compensation, or total return, to investors achieves the three standards of a fair return, i.e., financial integrity, capital attraction and comparable returns, but there is no single "right" way to achieve this objective.

## V. FACTORS TO CONSIDER IN DETERMINATION OF CAPITAL STRUCTURE

When the Board adopted the deemed capital structures for the Alberta utilities in Decision 2004-052, it considered a number of factors. These factors included business risk, comparable awards by regulators in other jurisdictions, interest coverage analysis and bond rating analysis. All of these factors are relevant considerations in determining an appropriate capital structure. This section addresses comparable awards by regulators in other jurisdictions, interest coverage (as well as other key credit metrics), and bond rating analysis as they relate generally to the utility sectors in Alberta and the ATCO Utilities. Section VI of my testimony will address business risk and the impact on the appropriate returns for the ATCO Utilities.

### A. Comparable Awards in Other Jurisdictions

When the Board made its findings in Decision 2004-052 with respect to the common equity ratios of each of the utilities, it used the allowed capital structures of other Canadian utilities as a point of reference or benchmark. Specifically, in determining the capital structures of the electric transmission utilities, it made comparisons with cost-of-service gas transmission pipelines regulated by the NEB, e.g., Foothills and TCPL-BC System (formerly ANG) and TQM. The EUB concluded that the business risks of the electricity transmission utilities were higher than those of the cost-of-service pipelines, whose allowed common equity ratios at the time of the Board's analysis were 30%.

Both Foothills and TCPL-BC System have since negotiated common equity ratios of 36%, or six percentage points higher than they were in 2004.[9] The Board also compared Nova Gas Transmission (NGTL) to the TCPL Mainline and concluded that NGTL faced higher business risks than the TCPL Mainline, whose allowed common equity ratio at the time of the Board's analysis was 33%. The EUB also compared NGTL to Westcoast, and determined that due to the risks of NGTL's large gathering system, NGTL was more similar to Westcoast than to the electricity transmission companies. Westcoast's 35% common equity ratio at the time represented a weighted average of a 30% allowed common equity ratio for its transmission mainline and approximately 38.5% for its regulated field services division. NGTL's allowed common equity ratio was set at 35%, two percentage points above that of the TCPL Mainline's 33% and equal to Westcoast's 35% weighted average common equity ratio for its transmission and regulated field services division.

The NEB subsequently approved an increase in the TCPL Mainline's allowed common equity ratio to 36%.[10] In May 2007, the NEB approved a multi-year settlement between TCPL and shippers that increased TCPL's deemed common equity ratio to 40%. Westcoast has also negotiated increases in its deemed common equity ratio for its transmission mainline since Decision 2004-052 was issued; for 2007, the deemed common equity ratio was 36%; Westcoast filed a negotiated settlement with the NEB in August 2008 which would maintain the transmission mainline common equity ratio at 36% from 2008-2010. With the increase in the deemed common equity ratio for the mainline transmission, and an actual common equity ratio of approximately 47% for the field services division at the end of 2007, the weighted average common equity ratio for Westcoast's combined transmission mainline and regulated field services would be approximately 42%.

---

[9] Foothills Pipe Lines Ltd., Order TG-08-2005, December 21, 2005; TransCanada PipeLines Limited, Order TG-02-2006, February 22, 2006. While TQM's deemed common equity ratio remained at 30% at the time this evidence was prepared, its application before the NEB requests an increase in the common equity ratio to 40%.

[10] National Energy Board, *Reasons for Decision*, *TransCanada PipeLines Limited, RH-2-2004, Phase II*, August 2005.

The NEB is not the only Canadian regulator to have increased allowed common equity ratios for utilities in its jurisdiction. Table 3 (below) presents other increases in allowed common equity ratios (and any related changes in the ROE) that have occurred since the EUB adopted the range of deemed common equity ratios in Decision 2004-052:

**Table 3**

| Company | Regulator | Decision Date | Equity Ratio | Change in Equity Ratio | Change in ROE (at 4.5% Long Canada) |
|---|---|---|---|---|---|
| Terasen Gas | BCUC | 3/06 | 35% | +2% | +0.60% |
| Terasen Gas (VI) | BCUC | 3/06 | 40% | +4% | +0.80% |
| Pacific Northern Gas | BCUC | 3/06 | 40% | +4% | +0.60% |
| Union Gas | OEB | 5/06 | 36% | +1% | none |
| Toronto Hydro | OEB | 12/06 | 40% | +5% | none |
| Enbridge Gas Distribution | OEB | 7/07 | 36% | +1% | none |
| Hydro One Transmission | OEB | 8/07 | 40% | +4% | none |

Including both the changes in the NEB-regulated pipeline capital structures and the changes by other regulators in Table 3 above, the benchmark approach that was used by the Board to establish appropriate levels of common equity ratios for the Alberta utilities would, in isolation, support an increase in the common equity ratios of the ATCO Utilities from the levels adopted in Decision 2004-052.

Consideration of comparable awards in other jurisdictions should not be limited solely to other Canadian utilities. The comparability criterion needs to be extended beyond domestic boundaries. Comparisons among utilities across borders, particularly by the bond rating agencies, are common. For example, S&P's peer comparison for AltaLink includes American Transmission Company and International Transmission Company, both U.S. companies.[11] Hydro One's peers include Consolidated Edison and National Grid, one a U.S. company and one a U.K. company with extensive U.S. holdings.[12]

[11] Standard and Poor's, *Research: Peer Comparison: North American Stand-Alone Transmission Companies Deliver Electricity… and Profits*, April 26, 2006.
[12] Standard & Poor's *Peer Comparison: Consolidated Edison Inc., Hydro One Inc. and National Grid PLC – Same Ratings, Different Basis,* October 11, 2005.

TransAlta Corporation's peers include PPL Corporation and Constellation Energy, both U.S. electric utilities.[13] Ontario Power Generation's peers have included two Canadian companies (TransAlta and Emera) and a U.S. company, Exelon.[14]

Since the Board issued Decision 2004-052, the Foreign Property Rule (FPR) was eliminated, effectively releasing investment that was previously captive to domestic markets. Prior to the elimination of the FPR, the Canadian bond market was largely a domestic market. As long as there was a cap on foreign investment, pension funds limited their foreign investments primarily to equities, and allocated their bond investments to Canadian bonds. The elimination of the FPR means that Canadian debt issuers increasingly compete for funds with global issuers.

The creation of a whole new market for Canadian dollar-denominated foreign bonds highlights the significance of the elimination of the FPR for debt issuers. These "Maple" bonds are particularly attractive to pension funds, whose liabilities are in Canadian dollars. Attracted by the low interest rate environment as well as the increasing demand for fixed income securities, foreign issuers raised funds in Canada in record amounts since the FPR was removed. During 2006 and 2007, approximately $55 billion of "Maple bonds" were issued by foreign investors. Approximately 40% of the amount has been raised by U.S. issuers.[15]

Historically, the existence of the FPR and the high demand in Canada for a relatively limited supply of high quality issues kept high grade Canadian bond spreads relatively low compared to spreads in the U.S. Over the ten year period ending December 2005, for example, the average spread between long-term A rated Canadian utility bonds and long Canada bond yields was approximately 115 basis points. By comparison, long-term A rated utility bond spreads in the U.S. market averaged 155 basis points. Since the elimination of the FPR, the spreads have converged. From January 2006 to end of

[13] Standard and Poor's, *TransAlta Corp*, October 22, 2008
[14] Standard and Poor's, *Research: Ontario Power Generation Inc.*, December 9, 2005
[15] DBRS, *Maple Newsletter*, Volume 3, Issue 2, April 9, 2008.

October 2008, the average spreads in Canada and the U.S. have been virtually identical (in the approximate range of 145 to 150 basis points).

The convergence of the spreads is an indication that Canadian utilities no longer have a built-in domestic advantage in raising capital. Moreover, they are competing with U.S. utilities with stronger financial metrics. The table below compares key credit metrics of Canadian utilities with those of A rated U.S. electric and gas utilities.

**Table 4**

| **Canadian and U.S. Utilities with Rated Debt** | **Ratings DBRS/Moody's/S&P** | **Common Equity Ratio (2007)** | **EBIT Interest Coverage (2005-2007)** | **FFO to Total Debt (2005-2007)** | **FFO Interest Coverage (2005-2007)** |
|---|---|---|---|---|---|
| **Canadian Utilities:** | | | | | |
| All | A/A3/A- | 42.2% | 2.4X | 14.5% | 3.2X |
| Electric T&D | A/Baa1/A | 44.1% | 2.8X | 16.3% | 3.7X |
| Gas Distribution | A/A3/A | 35.6% | 2.1X | 12.4% | 2.6X |
| Pipelines | A/A3/A- | 41.9% | 2.4X | 16.9% | 3.2X |
| **U.S. A-Rated Utilities:** | | | | | |
| Electric | -/A2/A | 49.2% | 3.5X | 20.5% | 4.6X |
| Gas Distribution | -/A3/A | 47.1% | 3.6X | 21.7% | 4.5X |

Definitions:

| | |
|---|---|
| Earnings before Interest and Taxes (EBIT) Interest Coverage: | Operating income divided by interest expense. |
| Funds from Operations (FFO) to Total Debt: | FFO equals net income plus depreciation, amortization and deferred taxes. FFO to debt equals FFO divided by total debt. |
| Funds from Operations (FFO) Interest Coverage: | FFO plus interest expense divided by interest expense. |

Source: Schedules 1 to 5

As the table above demonstrates, the credit metrics of Canadian utilities compare unfavourably to their U.S. peers. In setting the allowed return (combination of capital structure and ROE), the AUC needs to recognize that the Alberta utilities generally and the ATCO Utilities specifically should be allowed to achieve a similar degree of financing flexibility to that of their North American peers.

The actual credit metrics of U.S. utilities reflect the returns (a combination of the ROE and capital structure) that are awarded by regulators. During 2007 and 2008, the average common equity ratio adopted by U.S. regulators for gas distribution utilities was approximately 49% with corresponding awarded ROEs averaging 10.3%. The average common equity ratio adopted for electric utilities was 48%, with corresponding awarded ROEs averaging 10.4%.

## B. Interest Coverage Analysis

In its capital structure analysis in Decision 2004-052, the EUB concluded that an acceptable pre-tax interest coverage ratio for a taxable electric transmission utility was near two times and for a distribution utility was at or above 2.2 times. These coverage ratios were selected without a target credit rating in mind. Given the importance of maintaining ratings in the A category as discussed above, any interest coverage analysis should recognize that as an objective. Moreover, in so doing, it would be unreasonable to target the lowest possible level of coverage, as was the case in Decision 2004-052. If there are to be target credit metrics,[16] they need to provide a reasonable degree of financing flexibility, particularly important in a period of significant financing requirements, to provide a cushion if circumstances unfold unfavourably.

In Decision 2004-052, the EUB tested the implied coverage at the 2004 allowed ROE of 9.6%, the prevailing income tax rate of 33.87% and a range of embedded debt costs and common equity ratios. The Board also commented that some of the utilities had relatively high embedded costs of debt, but that those costs were expected to decline as older, higher cost debt was retired. Thus it can be inferred that the EUB expected a "natural improvement" in pre-tax interest coverage over time, that is, it expected a

[16] The key quantitative credit metrics of the debt rating agencies, Standard & Poor's, Moody's and DBRS, other than capital structure ratios, include cash flow metrics, e.g., funds from operations to total debt, rather than the EBIT coverage ratio used by the EUB in Decision 2004-052.

decline in the embedded cost of debt, but anticipated no reduction in the allowed ROE.[17] The embedded debt costs of the ATCO Utilities have, as anticipated, declined, by approximately 1.25% on average. Had there been no other changes, there would have been a "natural improvement" in pre-tax interest coverage ratios of less than 0.25X on average. However, the "natural improvement" in pre-tax interest coverage ratios that the EUB expected has been more than offset by countervailing factors.

First, as a result of the operation of the automatic adjustment formula, the allowed ROEs have declined almost as much as the ATCO Utilities' embedded costs of debt. Were there no change in the formula ROE, based on the October 2008 *Consensus Forecasts*, the 2009 ROE would be 8.45%, compared to 9.60% in 2004, a decline of over 1%, compared to the 1.25% decline in the ATCO Utilities' average embedded cost of debt. As a result, the "natural improvement" in the pre-tax interest coverage is insignificant, approximately 0.06X.

Second, as noted above, the combined federal/provincial corporate income tax rate in Alberta was 33.87%. The expected combined corporate income tax rates in 2009 and 2010 are 29% and 28% respectively, with further reductions to 26.5% and 25% in 2011 and 2012. All other things equal, the lower corporate income tax rates reduce pre-tax interest coverage ratios. At an embedded debt cost of 6.6% (approximately equal to the average ATCO Utilities' 2009 test year cost of debt), the existing deemed common equity ratios, and the existing formula ROE for 2009 of 8.45%, a reduction in the corporate income tax rate from 33.87% to 25% more than offsets any "natural improvement" in pre-tax interest coverage.[18]

[17] The Board did not test its interest coverage ratios at any ROE other than the ROE it adopted for 2004.
[18] The lower tax rate also raises the potential variability in after-tax equity returns. Effectively, a taxable utility can share downside business risk with the Canada Revenue Agency (CRA). The lower the corporate income tax rate, the larger will be the decline in the achieved return for a given percentage decline in operating income. In the Generic Cost of Capital proceeding, the Board recognized this principle when it adopted a higher deemed common equity ratio for the non-taxable than the taxable utilities. The reduction in the corporate income tax rate from approximately 34% in 2004 to the expected 25% in 2012 increases the variability of after-tax ROEs marginally.

Third, when the EUB did its analysis, the implicit assumption was that the utilities would collect an income tax allowance at the full statutory rates. This will not be the case for the foreseeable future for either ATCO Electric Transmission or Distribution. In Decision 2007-071, the EUB directed ATCO Electric to switch from using the future income tax approach for federal income tax calculations to the flow-through approach and to refund to customers the accrued future income tax liability. The flow-through method allows utilities to recover in the revenue requirement only those taxes that they expect to pay. The future income tax methodology recovers from customers an income tax allowance based on accounting (GAAP) income. The income tax code allows companies to claim capital cost allowances (CCAs) for plant that, in the early stages of the plant's life, exceed the book depreciation for that property, as well as claiming other current year deductions that are capitalized for accounting purposes. The higher income tax deductions reduce the amount of tax payable, and in the case of utilities which are required to use flow-through taxes, reduce the amount of income tax recoverable in rates. The extent to which the income tax payable (and recoverable) during a period of growth depends on both (1) the difference between the CCA rates and the book depreciation rates and (2) the proximity of the utility to "cross-over".[19]

For example, because both ATCO Electric Transmission and Distribution are in a period of relatively high growth and can claim CCAs at relatively high rates on key property classes (and other deductions), the CCAs will exceed the book depreciation by significant amounts, reducing the amount of tax recoverable in the revenue requirement relative to what would have been recovered under the future income tax methodology. The actual effective tax rate will be dependent on the allowed capital structure and return on equity (at the margin, each additional dollar of return is taxed at the statutory rate), but to provide some perspective, under flow-through taxes, the allowed ROE of 8.75% for 2008 and the previously deemed capital structures, the effective combined federal/provincial income tax rate for ATCO Electric in 2010 would be under 10%, compared to the statutory rate of 28%. The result is a reduction in cash flow available to finance capital additions, and deterioration in pre-tax interest coverage.

[19] Cross-over occurs when book depreciation exceeds tax depreciation.

Fourth, the interest coverage analysis that the EUB performed did not take account of the impact of construction work in progress (CWIP) on interest coverage ratios. CWIP results in "earnings", in the form of the Allowance for Funds Used during Construction (AFUDC), but creates no cash flow to service the debt and equity that must be issued to fund the construction of the facilities. Thus, in principle, if there is any CWIP being financed, all other things equal, the actual interest coverage will be lower than an interest coverage target calculated by reference to rate base. The extent of the impact will, obviously, be dependent on the proportion of CWIP to rate base. However, the following example highlights how significant the impact can be.

During the 2009 test year, ATCO Electric estimates that its total construction work in progress will exceed $500 million, compared to the mid-year net (of customer contributions) rate base of $2 billion (approximately 25% of net rate base), and compared to an annual average of just over $50 million in 2004-2006. Assuming a 65% debt/35% common equity capital structure, a full tax allowance at the statutory 2009 rate of 28%, a cost of debt (both embedded and new) of 6.5%, and a return on equity of 8.45%, the indicated pre-tax interest coverage using the test methodology set out by the EUB would be approximately 1.9X. Taking account of CWIP at 25% of rate base, the actual indicated pre-tax interest coverage ratio drops to 1.5X.

As the discussion above points out, as illustrated principally with circumstances that either have transpired since Decision 2004-052 or that were simply not recognized in the analysis, setting targets that are marginal at the outset can unnecessarily pressure actual credit metrics, ratings and debt costs.

While S&P no longer has a guideline for pre-tax interest coverage ratios, focusing instead, as indicated in footnote 16 above, on cash flow ratios, their previously published guidelines for pre-tax interest coverage ratios for low business risk utilities and ratings in the A category were as follows:

**Table 5**

| S&P Business Risk Ranking | |
|---|---|
| "2" | "3" |
| 2.3-2.9X | 2.8-3.4X |

Source: S&P, *Utilities and Perspectives*, June 1999

Although S&P no longer relies on either the business risk matrix that gave rise to these guidelines or the EBIT coverage guideline itself, the guideline ranges do provide a perspective on reasonable ratios for A ratings.[20] The guideline ranges for the lowest risk utilities support the conclusion that the <u>lowest risk utilities</u> should expect to be able to achieve pre-tax interest coverage in the middle of the range for a business risk ranking of "2", that is, 2.5 times.

S&P's current rating methodology assigns one of five business risk rating categories to each utility that it rates. The lowest risk category is "Excellent"; the highest risk category is "Vulnerable." The category assigned takes into account the regulatory environment in which the utilities operate. Most Canadian utilities, including CU Inc., are in the "Excellent" category.[21]

The business risk assessment is accompanied by a financial risk assessment. The financial risk assessment includes, but is not limited to, the consideration of the three key quantitative credit metrics referenced earlier, Debt/Capital, Funds from Operations (FFO)/Debt and FFO Interest Coverage. For each of the three metrics, S&P publishes a guideline range associated with four financial risk categories. The lowest risk

---

[20] Until November 2007, S&P utilized a global ratings methodology for utilities which included guidelines for a number of quantitative financial metrics for different business risk categories and ratings categories. Utilities were ranked on business risk from "1" to "10", with "1" being the lowest risk. Electric transmission utilities were generally accorded a business risk score of "1" or "2" (e.g., AltaLink, L.P. was a "2") and gas and electric distribution utilities in the range of "2" to "5". Newfoundland Power, for example, a distribution utility, was ranked "3". No Canadian utility was ever accorded a "1". Until 2006, the quantitative guidelines included pre-tax interest coverage. Since 2006, S&P's quantitative guidelines have been Total Debt/Total Capital, Funds from Operations to Total Debt, and Funds from Operations Interest Coverage.

[21] The other categories are "Strong", "Satisfactory" and "Weak". Nova Scotia Power, for example, is "Satisfactory".

category is "Modest"; the highest financial risk category is "Highly Leveraged". The table below presents the guideline ranges for each financial risk category. S&P notes that the guideline ranges are intended to represent the level of ranges that have been achieved historically and are expected to consistently continue.

**Table 6**

| | **FFO/Debt (%)** | **FFO Coverage (x)** | **Total Debt/Capital (%)** |
|---|---|---|---|
| Modest | 40 -60 | 4.0 -6.0 | 25 -40 |
| Intermediate | 25 -45 | 3.0 -4.5 | 35 -50 |
| Aggressive | 10 -30 | 2.0 -3.5 | 45 -60 |
| Highly leveraged | Below 15 | 2.5 or less | Over 50 |

Source: Standard & Poor's, *U.S. Utilities Ratings Analysis Now Portrayed in the S&P Corporate Ratings Matrix,* November 31, 2007

The matrix above is accompanied by a second matrix which indicates what the likely debt rating would be with a given business risk and financial risk profile. For example, a business risk profile ranking of "Excellent" and a financial risk ranking of "Intermediate" corresponds to debt ratings in the A category. Alternatively, an "Excellent" business risk profile ranking and an "Aggressive" financial profile are consistent with ratings in the BBB category.

While S&P does not apply their guidelines mechanically, the guidelines do provide guidance as to ranges that are considered appropriate for ratings in the A category. Based on S&P's guideline ranges, for example, the lowest risk Alberta utilities should reasonably expect to be able to maintain FFO interest coverage ratios of no less than 3 times.[22]

[22] DBRS has also published guidelines, but they do not distinguish by either business risk or investment-grade rating category. Thus they are less useful than S&P's guidelines. In addition, since the S&P ratings are generally lower than those accorded by DBRS, it is more likely that ratings in the BBB category would be by S&P. Since bond investors are more likely to focus on the lowest rating, it is appropriate to focus on the S&P guidelines.

## C. Bond Rating Analysis

In the Generic Cost of Capital proceeding, the Board considered the actual capital structures and corresponding bond ratings of various "pure-play" utilities as inputs into its determination of the deemed equity ratios for the Alberta utilities. Although there have been no upgrades or downgrades of Canadian utilities in reaction to recent regulatory decisions on ROE or capital structure,[23] the following related commentaries by the bond rating agencies indicate that the deemed common equity components of Canadian utilities, including the Alberta utilities, have continued to be perceived as relatively thin and the ROEs relatively low.

In December 2004, subsequent to Decision 2004-052, DBRS referred to the low deemed equity and returns as a "challenge" for the ATCO Utilities. The DBRS report for ATCO Ltd. stated,

> *"While ATCO's diversified operations, coupled with the Company's prudent management approach, provide a level of earnings stability, additional challenges over the medium term include the relatively low approved returns on equity (ROE) and deemed equity for the regulated businesses, continuing regulatory risk and lag and ATCO's merchant power exposure in Alberta."*

Additional DBRS reports citing the challenge of low approved common equity ratios and returns on equity have been published for Alberta utilities, i.e., CU Inc. (January 2007, May 2008), FortisAlberta (November 2005, May 2007, May 2008) and AltaLink (November 2005, May 2008). In reference to FortisAlberta, expressing the perspective of capital market participants on the comparable return requirement, DBRS commented that:

> *"In Alberta, as well as in many other jurisdictions in Canada, the rates of return and equity capitalization for ratemaking purposes allowed by regulators have been low in recent years, largely as a result of the low interest rate environment.*

[23] In early June 2008, five Ontario electricity transmission and distribution utilities were upgraded by S&P. The upgrades were attributed to increased clarity and predictability in the regulatory environment and stability in the provincial energy policy and electricity market framework.

*This has had a negative impact on earnings and cash flows. FortisAlberta's equity thickness at 37% and low ROE's directly impact shareholder returns, hindering the ability to attract capital for capital expenditure purposes. In addition, the allowed ROEs are significantly below those allowed for similar operations in the U.S. This acts as a disincentive for investors to allocate capital to Canadian utilities because they can earn higher rates of return in the U.S. from businesses having similar business risk profiles. (DBRS, Credit Rating Report: FortisAlberta, November 25, 2005)."*

In DBRS' *Year in Review and Outlook for 2007* (January 2007), the company cited two challenges faced by Canadian regulated utilities in 2006 that were expected to continue to put pressure on the sectors' credit metrics in the coming year. The first challenge was the historically low level of allowed rates of return which put downward pressure on earnings and cash flow. For 2007, DBRS expected that, in some cases, the low rates of return would be offset by higher equity ratios.[24] The second challenge was the need to finance increased capital expenditures to replace aging infrastructure and to meet increased demand due to growth in business.

Subsequent to Decision 2004-052, S&P commented on the thin equity layers allowed the ATCO group of utilities, stating,

*"The regulatory regime, although comparable with other provinces in Canada, typically approves less generous returns on thinner equity layers than those approved for ATCO's global peers. Approved returns for ATCO's regulated businesses are 9.6% on equity layers varying from 33%-43% of total capital. (S&P, Research Update: ATCO Group of Companies 'A' Ratings Affirmed; Outlook Stable, November 9, 2004.)"*

S&P has also made references to the low level of equity ratios and ROEs allowed in Decision 2004-052 for other Alberta utilities. In a 2006 report for AltaLink (rated A-), S&P stated,

[24] In its July 24, 2007 report on Toronto Hydro, DBRS stated "The return on equity of 9.0% in 2007 (also 9% in 2006) is an 88 basis point decline from 9.88% in 2005. However, the lower return on equity is expected to be somewhat offset as the equity component of the capital structure increases from 35% in 2007 to 40% in 2009."

> *"Like many Canadian regulated utilities, AltaLink's average financial profile is constrained by a comparatively low approved ROE (8.93% in 2006) on a thin deemed equity base of 35%. (S&P, Research Summary: AltaLink, May 15, 2006)"*

In S&P's December 22, 2005 report for NGTL, rated A-, the sole weakness cited for the pipeline was its high leverage associated with its regulated capital structure.

In the S&P report for Union Gas issued subsequent to the utility's 2006 settlement in which the allowed common equity ratio was raised to 36%, the two weaknesses referred to were the high leverage associated with the company's regulated capital structure and the relatively low allowed ROE compared with global peers.(S&P, *Research: Union Gas*, August 24, 2006).

In a recent report for CU Inc., S&P stated,

> *"Rates of return and deemed equity layers are somewhat low in comparison to global peers but are similar to other Canadian utilities (S&P, CU Inc., October 30, 2008)"*

In general, S&P considers that Canadian utility financial policies tend to be aggressive with leverage, and regulators "parsimonious" with returns.[25] As noted above, the "aggressive leverage" is largely a result of regulatory directives.

With respect to other capital market participants, in the NEB's August 2005 *Canadian Hydrocarbon Transportation System* report, pension funds indicated to the regulator that the basic financial parameters (allowed return on equity and deemed capital structure) in its regulatory scheme should be improved. In its 2006 report of the same name, the NEB reported that a number of analysts felt that the ROE generated by the NEB formula and by other Canadian regulators' formulas "were a little too low" and not supportive of dividend growth or credit metrics. A number of analysts commented that where they have "Buy" recommendations on utility stocks, the recommendations tend to reflect the

[25] Standard & Poor's, *Industry Report Card: Regulatory Rulings, M&A, and Fuel Cost Recovery Dominate Global Utilities Credit Environment*, November 21, 2006.

prospects of the unregulated operations.[26] Analysts also commented that companies have reduced costs and taken other steps to improve profitability and dividend growth for several years, and wondered how long that could continue. A similar theme is repeated in the 2007 report, in which the NEB reported that some parties expressed concern that the stand-alone pipeline entities might have difficulty attracting capital given low ROEs, despite the substantial liquidity in the capital markets at the time the parties were surveyed.[27] Other parties felt that the stand-alone entities would be able to attract capital, but the terms under which they did so would be more costly than for the consolidated entities.[28]

In summary, the debt rating agencies clearly view the credit metrics of the Canadian utilities as weak for their ratings and the key elements which are determinative of those metrics, capital structure and ROE, out of line with those of the Canadian utilities' global peers.[29]

[26] In many cases, the ROEs achieved by the entity whose shares are traded have been materially higher than the ROEs allowed under the formulas. The allowed ROE generated by the NEB formula averaged 9.6% over the period 2002 to 2005; the ROE reported for TransCanada PipeLines Ltd by DBRS over that same period was 12.7%. For Terasen Gas, its allowed ROE averaged 9.2%; Terasen Inc.'s ROE (as reported by DBRS) averaged 11.1%. DBRS reported an average ROE of 13.0% for Canadian Utilities Ltd, compared to the regulated subsidiaries' allowed ROEs of approximately 9.6% over the same period.

[27] Strong evidence exists that the automatic adjustment formulas are not producing returns that meet the fair return standard. Returns negotiated by arms' length parties on new pipeline investment are much higher than the formula returns governing existing pipeline investments. This differential cannot be justified by risk differences. Negotiated returns on some new pipeline investments (e.g., Enbridge's Alberta Clipper, Line 4, and Southern Lights and the TransMountain system and expansion) have been 2.25 percentage points or more higher than the NEB's multi-pipeline formula return on equity.

[28] The NEB did not consult with analysts for the purpose of their 2008 report, in light of the ongoing cost of capital proceeding for TQM.

[29] While relatively few equity analysts have commented on the low level of common equity ratios and the ROEs, in *Pipelines/Gas & Electric Utilities*, December 7, 2006, Karen Taylor, equity analyst for BMO Capital Markets, concluded, "We believe on a collective basis, that the allowed returns as established by the formulas highlighted above [referring to the NEB, EUB, BCUC and OEB formulas] are confiscatory and likely violate the Fair Return Standard."

## VI. RETURNS FOR THE ATCO UTILITIES

### A. Summary of Benchmark Recommendations

Table 7 below is a summary of the recommendations of Mr. Coyne for each Alberta utility sector. The table represents his conclusions regarding the appropriate range of common equity ratios and the associated ROEs for a benchmark Alberta electric transmission, electric distribution, gas distribution and gas transmission utility.

**Table 7**

| Summary of Recommended Common Equity Ratios and Applicable ROEs | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Utility Sector** | **Common Equity Ratios** | | | | | | |
| | **50%** | **48%** | **46%** | **44%** | **42%** | **40%** | **38%** |
| **Electric Transmission** | N/A | N/A | 9.5% | 9.7% | 9.9% | 10.2% | 10.5% |
| **Electric Distribution** | N/A | N/A | 9.8% | 10.1% | 10.3% | 10.6% | 10.8% |
| **Gas Distribution** | N/A | N/A | 10.2% | 10.5% | 10.7% | 11.0% | 11.2% |
| **Gas Transmission** | 10.1% | 10.3% | 10.5% | 10.8% | 11.0% | 11.3% | 11.6% |

Source: Testimony of James Coyne, Table 1.

The following sections provide my assessment of the business and regulatory risks of the individual ATCO Utilities with the objective of determining what, if any, adjustments to the benchmark common equity ratio and/or ROE are required to reflect any unique differences which would result in their cost of capital differing materially from that of a benchmark Alberta utility in the same utility sector.

## B. ATCO Electric

ATCO Electric operates in northern Alberta and portions of east-central Alberta. Its service area is largely rural and remote, covering nearly two-thirds of the province geographically. Despite the size of its service area, it serves only about 12% of the population of the province and approximately 15% of the load. Its largest population centers include Fort McMurray, Grande Prairie and Lloydminster. The economic base of the service area is principally the oil and gas industry; agriculture and forestry (Grande Prairie area) are also an important part of the economic base. Industrial load accounts for approximately 68% of ATCO Electric's total load and approximately 49% of total load is attributable to the oil and gas industry (approximately 38% of revenues). ATCO Electric's rural nature and reliance on a single resource-based industry distinguish it from other transmission and distribution utilities in Canada whose economic and customer base are more diverse and/or densely populated, for example, Hydro One (transmission), Toronto Hydro and the distribution utilities that serve the urban areas of Edmonton and Calgary.

Since Decision 2004-052 was issued, the Alberta economy has been driven by a boom in the oil industry, underpinned by high oil prices and accelerating oil sands development. ATCO Electric's service territory includes all three of the key oil sands deposits, Athabasca, Cold Lake and Peace River. The boom in the oil industry translated into a boom in the Alberta economy that was unmatched by any other province in Canada. Since 2004, the real growth in GDP in Alberta outstripped the rest of the country as shown below.

**Table 8**

| | 2004 | 2005 | 2006 | 2007 | 2004-2007 |
|---|---|---|---|---|---|
| **Alberta** | 5.2% | 5.3% | 6.6% | 3.3% | 5.1% |
| **Canada** | 3.1% | 3.1% | 2.8% | 2.7% | 2.9% |

Source: Statistics Canada

Comparisons with the national figures, particularly for 2006, are somewhat misleading, due to the influence of the economic performance in Alberta on the national averages. For example, real growth in GDP in Canada in 2006 exclusive of Alberta was approximately 2.1%, compared to 2.8% including Alberta.

Alberta has surpassed the country as a whole in virtually every economic indicator over the past several years, as the table below demonstrates.

**Table 9**

| | **Alberta (2004-2007)** | **Canada (2004-2007)** |
|---|---|---|
| Growth in Disposable Personal Income | 10.0% | 4.8% * |
| Growth in Retail Sales | 11.7% | 4.7% * |
| Growth in Average Weekly Wages | 4.4% | 2.9% |
| Growth in Population | 2.4% | 0.9% * |
| Unemployment Rate | 3.9% | 6.6% |
| Growth in Housing Starts | 7.5% | -0.3%* |
| Increase in Consumer Prices | 3.3% | 2.1% |

* Excludes Alberta

Source: Statistics Canada

The growth experienced in Alberta from 2004-2007 was considerably higher than had been anticipated in 2003-2004. In its *Provincial Outlook 2004: Long-term Economic Forecast*, the Conference Board of Canada had forecast an average real GDP growth rate of 2.9% for 2004-2007 and 2.8% for the 10-year period 2004-2013 for Alberta, compared to 2.8% and 2.7%, respectively, for Canada. In its March 2008 *Provincial Outlook 2008*, the Conference Board had revised its growth forecasts for Alberta upward, anticipating growth over the 10-year period 2008-2017 of 3.2%, spurred by the oil industry, compared to 2.6% for the rest of Canada. The expected growth in Alberta, particularly in the oil sands areas, in turn has been forecast to increase the demand for electricity by approximately 3.3% per year from 2007 to 2017.[30]

[30] Alberta Electric System Operator, *Future Demand and Energy Outlook 2007-2027,* Table 1, December 21, 2007.

While high growth constitutes an opportunity for ATCO Electric, it also entails higher risks. Recently, both labour and materials costs in Alberta have risen more quickly than inflation generally. While the current economic downturn has eased cost pressures temporarily, a tight labour market, particularly for skilled workers, high wages and costs of basic materials will keep pressure on ATCO Electric's costs of providing service.

The growing demand for electricity over the next decade is anticipated to lead to an unprecedented level of capital expenditures in the ATCO Electric service area. While total gross capital expenditures for transmission and distribution were close to $650 million ($270 million for transmission and $380 million for distribution) during 2004-2006, the total forecast for 2009-2011 is over $2 billion ($1.3 billion for transmission and $0.8 billion for distribution). By 2011, the total transmission and distribution rate base is expected to exceed 2.5 times what it was (in current dollars) in 2004.[31]

With specific respect to the transmission operations, ATCO Electric anticipates close to $1.3 billion in capital expenditures during 2009-2011 alone related to relatively large scale projects direct-assigned by the AESO; ATCO Electric's potential capital expenditures required to meet the AESO's demand forecasts and transmission plan are potentially double that amount.[32] Large scale transmission projects are by their very nature longer-term than projects related to conventional capital maintenance.

While ATCO Electric has a capital deferral account associated with transmission projects that are direct-assigned by the AESO, the projects are not placed into rate base until they are complete. In the meantime, the costs of planning, development and construction must be financed. The period over which the costs must be financed and the magnitude of those costs is uncertain; the projects are subject to delays and deferrals, and higher than anticipated costs of materials, supplies and labour. The

[31] ATCO Electric's net assets will have grown from $1.4 to $3.5 billion. The $3.5 billion excludes approximately $800 million of contributions related to assets for which ATCO Electric will have responsibility for operating and maintaining.

[32] In the January 2007 *Planning for Alberta's Power Future*, January 2007, the AESO identified a potential need for $3.5 billion in transmission investment in Alberta over the next 10-years over and above the $1.2 billion in investment related to projects already in progress. The AESO is scheduled to issue a revised plan by the end of 2008, which is likely to indicate higher investment requirements.

longer the project is in the planning and construction stages, the longer the recovery of the associated costs is deferred. The regulatory environment in Alberta provides a reasonable degree of assurance that the expended costs will be recoverable; nevertheless, the deferral of recovery, i.e., the accumulation of construction work in progress (CWIP), as previously discussed, will put pressure on the utility's financial performance. In sum, ATCO Electric is facing a period of high growth, with the attendant risks of managing that growth.

The long-term outlook for the Alberta economy, which is inextricably tied to the growth in the oil sands, is not without downside risks, as the current economic downturn illustrates, with some oil sands projects being delayed. The continued development and production of the oil sands is premised on oil prices remaining at levels sufficient to cover the higher costs (relative to conventional oil) associated with these activities. Sustained low world oil prices, a persistent reduction in global demand, changes in energy policy in the U.S., stricter environmental standards, including $CO_2$ restrictions, availability of water and natural gas, are all factors that can delay development of, or curb, future production in the oil sands. A prolonged decline in the Alberta economy would negatively impact ATCO Electric's ability to recover a compensatory return on and the full return of its investment over the longer term.

On balance, it is my judgment that the level of business risk faced by both ATCO Electric's transmission and distribution operations has increased since Decision 2004-05, largely due to higher short-term forecasting risks, deferral of cost recovery related to large scale projects (applicable principally to transmission), and higher exposure in the longer-term to the fortunes of the oil sands. Other business risk factors (e.g., reliance on deferral accounts, cost recovery through rate design) have not changed materially, that is, there have been no offsetting reductions in business risk.

With respect to the relative risk of ATCO Electric Distribution and Transmission, Transmission faces lower business and regulatory risk than Distribution. ATCO Electric Transmission collects its approved revenue requirement monthly from the AESO, and thus is not exposed to shortfalls in revenue due to weather or economic conditions. ATCO Electric Distribution, in contrast, collects its forecast revenue requirement from retailers in rates that are, depending on the customer class, a combination of basic customer charges, peak demand and energy. Since ATCO Electric Distribution collects revenues from retailers, including large commercial and industrial customers who are designated as self-retailers, it faces higher credit risk than ATCO Electric Transmission. It also faces higher revenue risk due to potential shortfalls due to lower than forecast demand/consumption due to economic conditions and, to a lesser degree, from weather.[33] Although it does not purchase and sell power directly to customers, ATCO Electric Distribution retains the supplier of last resort obligation. While ATCO Electric Transmission has the benefit of a deferral account for capital expenditures related to direct-assigned projects, the longer term nature of large transmission projects whose timing is largely controlled by the AESO exposes ATCO Electric Transmission to higher risks of deferred cost recovery than ATCO Electric Distribution. On balance, the business and regulatory risks of ATCO Electric Transmission, and thus the cost of capital, are lower than those of Distribution.

As regards the relative risk of ATCO Electric Transmission relative to its Alberta peers, the closest comparable is AltaLink, the only stand-alone investor-owned transmission utility in Canada. AltaLink operates in a similar economic environment to ATCO, faces the same regulatory model as ATCO and the same issues with respect to large-scale transmission projects. I see no factors that would result in ATCO Electric Transmission, on a stand-alone basis, facing a materially different cost of capital than AltaLink.

In that context, it bears noting that S&P, in a comparative study of AltaLink and two stand-alone U.S. transmission companies (American Transmission Co.(ATC) and Independent Transmission Co.), concluded that AltaLink faced higher business risk than ATC. This conclusion was largely due to S&P's conclusion that ATC faced the lowest

[33] In its May 2008 report for FortisAlberta, DBRS noted that "The demand for electricity in Alberta and, more specifically, for the Company, is only moderately sensitive to changes in the weather because the majority of the province uses natural gas for heating purposes and the summer months do not tend to require air conditioning to the same extent as in other regions."

regulatory risk of the three transmission companies. S&P referred to ATC's FERC-approved settlement that includes a 12.2% ROE based on a hypothetical capital structure of 50% equity, the ability to earn a return on CWIP, the fixed monthly fee charged, which reduces exposure to cash flow variability, rate setting based on prospective data, and an annual end-of-year true up. S&P noted that the CWIP treatment is an important feature that reduces upfront financing risk and liquidity concerns, given the company's large planned capital expenditure program.[34]

Outside of Alberta, all of the Canadian transmission utilities are owned by provincial governments. Of those, only Hydro One Inc. has (1) electric transmission operations which make up more than 50% of its assets; and (2) rated debt which is not guaranteed by the provincial government and thus has financial parameters that have been at all "tested" in the capital markets.[35] Nevertheless, as a provincially-owned utility, Hydro One's debt ratings reflect the support of its owner, the province of Ontario.[36] Since the OEB has recently set the cost of capital for both electric transmission and distribution utilities, its relative cost of capital determinations are informative.[37] The OEB's decisions have effectively found the business and regulatory risks of electric transmission and distribution in that province to be the same, allowing the same ROE and capital structure (40% equity) for both. In Alberta, the cost of capital would be lower for electric transmission than distribution, largely given the different rate structures. In Ontario, the rate structure of Hydro One's transmission operations exposes it to earnings variability from weather (marginally), conservation and economic conditions.

[34] S&P, *Peer Comparison: North American Stand-Alone Transmission Companies Deliver Electricity… and Profits",* April 2006.

[35] Comparisons are made to other utilities with rated debt, as the ratings provide some objective measure of the companies' business and regulatory risk profile.

[36] Moody's rates Hydro One using its rating methodology for government-related issuers. Prior to adopting the government-related issuer methodology, Moody's rated Hydro One A2 (corresponding to S&P/DBRS ratings of A). S&P gives Hydro One a "one notch" higher credit rating because of its government ownership. In other words, S&P would rate Hydro One "A" were it not for its government ownership.

[37] OEB, Hydro One, EB-2006-0501, August 16, 2007 and *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors,* December 20, 2006.

With respect to electric distribution, the closest comparable in Alberta is FortisAlberta, the only stand-alone investor-owned distribution utility in the province. FortisAlberta is subject to the same regulatory model (e.g., deferral account for changes in electric transmission rates)[38] as ATCO and faces similar issues with respect to expansion of the distribution system. The principal difference is that FortisAlberta is somewhat less exposed to industrial load than ATCO Electric.[39] On balance, however, there are no factors unique to ATCO Electric Distribution that, on a stand-alone basis, would result in its cost of capital being measurably different from that applicable to FortisAlberta. Thus, estimates of the cost of capital for a benchmark Alberta distribution utility are directly applicable to ATCO Electric Distribution.

Outside of Alberta, the principal investor-owned Canadian electricity distribution comparators with rated debt are Newfoundland Power and Maritime Electric. The only other investor- owned electric utilities in Canada are vertically-integrated utilities which continue to provide bundled service (Nova Scotia Power and FortisBC). In Ontario, there are five municipally-owned distribution utilities (in addition to Hydro One, which as previously noted, is a combination transmission/distribution utility) with rated debt (all in the A category).

With respect to the relative risk of Alberta distribution utilities versus other Canadian distribution utilities, Newfoundland Power (rated A by DBRS and Baa1 by Moody's) and Maritime Electric (rated A by S&P) both serve less attractive and economically diverse markets than the Alberta markets, with less growth opportunity; on the other hand, their customer bases are considered to be relatively stable. Newfoundland Power, which has a relatively large heating load, has the benefit of a weather normalization clause and the ability to pass through 100% of purchased power costs to customers. Maritime Electric, on the other hand, while it has a fuel adjustment mechanism, is exposed to some risk of underrecovery (and deferred recovery) of its purchased power costs. While Newfoundland Power would be considered of approximately similar business and

[38] The Alberta distribution utilities are at risk for variations in transmission demand.
[39] DBRS, *Rating Report: FortisAlberta Inc*., May 2008, states that residential and commercial customers provide the bulk of FortisAlberta's margin.

regulatory risk to the typical Canadian distribution utility, Maritime Electric would be viewed by investors as facing higher than average risk.

The five large municipally-owned Ontario distributors, Toronto Hydro, Hydro Ottawa, London Hydro, Enersource[40] and Veridian,[41] all serve medium-sized to large urban areas, with customer bases that are predominantly residential and commercial.[42] They have no supply assurance obligation and an ability to pass through purchased power costs to customers. While the incentive regulation model relied upon in Ontario creates somewhat higher risks relative to cost of service regulation, the incremental risks have been mitigated by the approval of accounts designed to capture and pass through costs related to a key provincial initiative, the installation of smart meters. Political intervention risks, which were of concern to the debt rating agencies in the past, have been largely mitigated as a result of an extended period of stability in the Ontario electricity market and increased transparency in the OEB's regulatory framework. On balance, the large Ontario distributors do not face materially higher or lower business and regulatory risks than the typical Canadian electricity distributor.

In summary, a comparison of the electricity distributors in Alberta and Canada reveals no factors that would lead to a measurable difference in the cost of capital for a benchmark Alberta distribution utility versus that of an average risk Canadian distribution utility or between ATCO Electric Distribution and an average risk Canadian distribution utility.

Mr. Coyne's testimony develops a range of ROEs and capital structures for benchmark Alberta transmission and distribution utilities by reference to a sample of low risk U.S. electric utilities. His analysis and recommendations take into account (1) the lower risk of transmission and distribution utilities relative to a vertically integrated utility with generation assets, and (2) by focusing on the bottom end of his range of results for a

[40] Enersource serves Mississauga, the 6th largest municipality in Canada.
[41] Veridian serves nine municipalities in east-central Ontario, including Ajax, Belleville, and Pickering.
[42] For example, DBRS states that more than 95% of Toronto Hydro's electricity sales are to residential and general service customers, which have relatively stable demand year over year, as these customers are less sensitive to economic cycles.

combined transmission/distribution utility, the relatively lower risk of Alberta electric transmission versus distribution operations. As there are no ATCO Electric specific factors which would result in a materially higher or lower cost of capital relative to the benchmark results, Mr. Coyne's cost of capital estimates are directly applicable to both ATCO Electric Transmission and Distribution.

ATCO Electric is proposing common equity ratios within the range recommended in Mr. Coyne's evidence, specifically 38% for ATCO Electric Transmission and 40% for ATCO Electric Distribution. Given that there is no need to make any adjustments to the cost of capital results for differential ATCO Electric business and/or regulatory risks, the corresponding ROEs for ATCO Electric Transmission and Distribution are 10.5% and 10.6% respectively.

## C. ATCO Gas

As the principal natural gas distributor in the Province of Alberta, ATCO Gas is effectively the benchmark Alberta gas distributor. ATCO Gas serves approximately one million customers in eleven large and medium sized metropolitan areas, 279 smaller communities and some rural areas throughout the province. ATCO Gas is solely a transporter of natural gas; the sale of its retail energy service business to Direct Energy Marketing Limited, announced in December 2002, was finalized in May 2004.[43] Its customer base is largely residential and commercial (approximately 50% and 45% of volumes respectively).

The residential and commercial focus of its customer base potentially exposes ATCO Gas to a significantly higher weather-related revenue fluctuation than a gas utility which has a more balanced (as among residential, commercial and industrial) customer base. The weather-related volatility has been partially mitigated through rate design, which allows ATCO Gas to recover approximately 56% of its fixed costs through fixed

[43] The sale of the retail energy business was known in advance of the last Generic Cost of Capital proceeding

charges.[44] The rate design is fully consistent with the Board's stated philosophy, that is, that the utilities should strive for a rate design that reflects the manner in which costs are incurred. The Board had articulated this philosophy well in advance of the last Generic Cost of Capital hearing and decision.[45]

In Decision 2008-113 dated November 13, 2008 the AUC approved ATCO Gas' requested weather normalization deferral account which further mitigates earnings volatility arising from unpredictable variations in weather. The impact of the proposed weather deferral account, in isolation, on ATCO Gas' cost of capital is largely judgmental. There are no market data that permit the segregation of the effect of the account on the overall cost of capital. For those utilities in Canada that have such accounts, there have been only two for which the regulator has ascribed a specific value to an account designed to adjust for weather fluctuations. In the case of both Terasen Gas (1994)[46] and Pacific Northern Gas (2003), the BCUC deducted ten basis points from the utilities' equity risk premiums when it approved their Revenue Stabilization Adjustment Mechanisms (RSAMs). However, the RSAMs approved for the two utilities are more comprehensive than the weather deferral account proposed by ATCO Gas. The RSAMs also take account of variances in revenues from weather-sensitive customer classes due to variances in per customer usage from other sources (e.g., conservation).

ATCO Gas' approved weather normalization deferral account will only take into account variations in earnings due to weather. ATCO Gas will continue to be at risk for declining average customer usage. Between 2001 and 2009, ATCO Gas' normalized average per residential customer usage is expected to decline on average by approximately

---

[44] In Decision 2007-026, ATCO Gas was allowed to increase its customer charge, resulting in an increase in its recovery of fixed costs (on a forecast basis) in a fixed charge (customer or demand charge) from approximately 47% of the total distribution cost of service at the time of the last Generic Cost of Capital proceeding to approximately 56%.

[45] For example, in Decision 2004-067 (August 13, 2004) for EPCOR Distribution at page 162, the Board stated that in recent decisions it has encouraged utilities to move to revenue-to-cost ratios of 1.0 by cost component, citing Decision 2001-38 (May 16, 2001) for ATCO Electric. In Decision 2001-38, the Board stated, "If a utility's cost structure had more fixed costs than variable costs, a regulator would expect the rate to have higher fixed charges relative to variable charges."

[46] The 10 basis points were later restored when Terasen Gas moved to performance-based regulation.

1.5% per year. The decline in residential per customer usage is similar to the industry experience in North America. The decline in per customer usage in the industry is in part related to "natural conservation", that is, new construction is more energy efficient. It is also related to customer-driven efforts to reduce their consumption, particularly in reaction to rising natural gas prices, as well as to utility-led efforts to encourage conservation. With the increased volatility of natural gas prices that has been observed since 2000, the net impact of these factors on customer usage becomes increasingly difficult to forecast.[47]

In contrast to the reduction in per customer usage that has been experienced (and is expected to continue) in the North American gas distribution industry, the average use per customer in the electric utility industry has generally been rising over time.[48] In Alberta, the average use per residential customer was relatively flat between 1993 and 2007.[49]

Any small reduction in cost of capital from the approval of the weather normalization deferral account is more than offset by the higher risks associated with managing the high level of growth that ATCO Gas is facing. Similar to ATCO Electric Distribution, the growth in Alberta has required ATCO Gas to increase capital expenditures to meet customer requirements. Growth in capital expenditures is expected to exceed 10% per year between 2004 and 2009. Actual capital expenditures outstripped GRA approved amounts over 30% on average annually from 2004-2007. Capital expenditures as a percent of net property, plant and equipment (PPE) averaged 13% in 2006-2007 and are expected to be close to 15% on average from 2009-2011. To put this in

---

[47] In a report prepared for the Canadian Gas Association entitled *Declining Average Customer Use of Natural Gas: Issues and Options*, December 2006, Indeco noted that "Utilities, such as ATCO Gas, AltaGas, Enbridge Gas Distribution and Union Gas, with the highest percentages of residential gas customers in markets where natural gas is the predominant residential fuel, have the largest potential impact on profitability because of any declining average use per customer in this sector." (p. vii)

[48] Moody's Investor Service, *Impact of Conservation on Gas Margins and Financial Stability in the Gas LDC Industry*, June 2005.

[49] Alberta Energy and Utilities Board, *Statistical Series 2003-28: Alberta Electric Industry-Annual Statistics for 2002,* July 2003; Thon, Scott, *Alberta Electricity Industry Restructuring: Implication for Reliability*, August 2005; Alberta Energy, *Backgrounder Electricity/SP,* October 2005; Alberta Energy Website, *http://www.energy.gov.ab.ca/537.asp,* February 22, 2007.

perspective, the average capital expenditures to PPE for other mature gas distribution utilities in Canada outside of Alberta during 2006-2007 was approximately half of that of ATCO Gas. As a result of the growth that ATCO Gas is experiencing, the rate base is expected to double between 2003 and 2011.

On balance, it is my judgment that, with the change in rate design and the approval of the weather deferral account, the level of business risk that ATCO Gas faces has not materially changed since Decision 2004-052. While the Company would achieve improved protection from weather variability, it is exposed to higher cost recovery risks associated with the increasing uncertainty of customer usage and rapid growth.

With respect to its relative business and regulatory risk versus other investor-owned Canadian gas distributors with rated debt (Enbridge Gas, Gaz Métro, Pacific Northern Gas, Terasen Gas, and Union Gas), ATCO Gas faces somewhat higher fundamental business risks than Enbridge Gas due to the latter's more balanced (among customer classes) customer base and more diversified economy. While ATCO Gas has no material industrial customer base of its own, the underlying economic base is more tied to cyclical resource-based industries than Enbridge Gas. Pacific Northern Gas and Gaz Métro are significantly more dependent on industrial load than the typical Canadian gas utility; Terasen Gas and Union Gas also have material industrial load but also a large, diverse residential and commercial base. PNG, Terasen and Gaz Métro face higher competitive risks than average primarily due to competitive electricity prices in British Columbia and Québec.

With respect to the regulatory framework, Pacific Northern Gas, Terasen Gas and Gaz Métro have a more comprehensive slate of deferral accounts than ATCO Gas, which help temper their fundamental business risks. For example, all three have mechanisms that protect their revenues from weather and declines in customer usage. They also have deferral accounts for differences between forecast and actual interest rates. While Enbridge and Union remain exposed to weather risk, they also have mechanisms to adjust rates for declines in customer usage. All of the gas utilities other than ATCO continue to sell gas but have no commodity risk, as they have purchased gas accounts (PGAs) which allow them to pass through differences between actual and forecast gas costs. Enbridge, Terasen and Union can also pass through in the PGAs differences between forecast and actual pipeline transmission costs. By comparison, ATCO Gas is at risk for variations between forecast and actual demand on the ATCO Pipelines system.

Except for PNG, all of the rated gas utilities are subject, in differing degrees, to some form of performance-based regulation. While performance-based regulation can expose a utility to higher risk than cost of service regulation, the extent of any increase is case specific. For Terasen Gas, for example, the incentive mechanisms are limited to operating and maintenance expenses and base capital expenditures, with earnings above and below the allowed ROE shared 50/50 with customers, and the company continues to be subject to annual reviews. In the case of Gaz Metro, the incentive mechanisms provide upside potential only. In no Canadian gas utility case has a higher cost of capital been awarded when performance-based regulation was adopted.

Considering both the fundamental risk factors and the regulatory framework, ATCO Gas faces lower business and regulatory risks than Gaz Metro or PNG, but is of relatively similar business and regulatory risk to the three largest Canadian gas distributors, Enbridge, Terasen and Union. In turn, these three gas distributors, and ATCO Gas, would face no less business and regulatory risk than the U.S. gas distributors which make up Mr. Coyne's proxy sample given the nature of their markets and the regulatory framework under which they operate (e.g., straight fixed variable rate design in the case of Atlanta Gas Light), weather normalization and/or decoupling mechanisms for all six of the proxy companies. Consequently, there is no need to make an adjustment to the benchmark gas distribution utility cost of capital estimates for ATCO Gas.

ATCO Gas is proposing a common equity ratio within the range recommended in Mr. Coyne's evidence, specifically 40%. At a 40% common equity ratio, the corresponding ROE for ATCO Gas is 11.0%.

## D. ATCO Pipelines[50]

ATCO Pipelines is a relatively small gas pipeline serving an intra-Alberta market. It has access to export markets only indirectly via accessing other pipelines, primarily, and to a much lesser extent, Alliance Pipeline and Many Islands Pipelines/TransGas. To put its relative size into perspective, ATCO Pipelines' total assets and revenues were approximately $795 million and $161 million, respectively, in 2007. By comparison, NGTL's 2007 total assets and revenues were $4.4 billion and $1.2 billion respectively.

ATCO Pipelines serves three types of customers; industrials, producers and the core market, comprised of local gas distribution companies, which, in turn, deliver to residential, commercial and small industrial end-users. The industrial and producer customers account for approximately 49% of ATCO Pipelines' regulated revenues; the core market accounts for most of the remainder.

ATCO Pipelines competes with NGTL for both producer and industrial deliveries. ATCO Pipelines charges a receipt toll to producers for volumes entering its transmission system and a delivery toll to end users (industrials and core customers) taking delivery of gas from its system. The delivery toll is based on ATCO Pipelines' fully allocated cost of service. NGTL charges a receipt toll for volumes entering its system, and a delivery toll for intra-Alberta industrial deliveries of approximately 1.3 cents per GJ based solely on NGTL's metering costs. To retain and attract industrial load, ATCO Pipelines' fully allocated cost of service toll plus the commodity cost of gas on the AP system must compete with NGTL's "metering costs only" toll plus the commodity cost of gas on the NGTL system.

[50] ATCO Pipelines has reached a settlement of its 2008 and 2009 GRA which includes reliance on the 43% common equity ratio adopted in Decision 2004-052 for both 2008 and 2009. The ROE for both 2008 and 2009 will be the 2008 automatic adjustment formula ROE. As regards 2010 and beyond, ATCO Pipelines has signed a Memorandum of Agreement with NGTL to provide integrated gas transmission services in Alberta. As there are significant steps which must be taken in order for the agreement to be finalized, there remains considerable uncertainty whether the agreement will be implemented, and if it is, the timing thereof. As a result, the business risk profile of ATCO Pipelines has been assessed assuming the status quo.

The competitiveness of ATCO Pipelines' receipt tolls with NGTL's receipt tolls is impacted by "dual tolling". To the extent that receipts onto the ATCO Pipelines system exceed deliveries to end-users, incremental volumes entering the ATCO Pipelines system must exit the system by being delivered to another pipeline, usually NGTL. The "excess" gas volumes incur dual tolls. ATCO Pipelines attempts to "match" producer receipts with markets to minimize deliveries onto the NGTL system and thus dual tolling.

To attract and maintain producer receipts on its system, ATCO Pipelines needs to retain its industrial load. Thus, the retention of industrial volumes is important to the viability of the ATCO Pipeline system. Loss of industrial volumes, due to closure, fuel switching, economic slowdown, low product prices, or switching transmission systems, negatively impacts producer receipts, which are responsible for approximately 30% of ATCO Pipelines' total regulated revenues. The negative impact on producer receipts arises because, without industrial volumes on ATCO Pipelines, there is less on-system market for producer receipts and the dual toll concern arises at lower volumes, forcing producers to other systems. ATCO Pipelines has recently experienced decontracting by three industrial customers due to facilities closures, project deferral and reduced demand.

To retain industrial load (or to attract new industrial load), ATCO Pipelines must compete primarily with NGTL, but potentially with other pipelines as well. With respect to NGTL, as noted above, ATCO Pipelines must compete with NGTL's 1.3 cents per GJ intra-Alberta delivery toll, as well as with NGTL's investment policy, both of which are more attractive to industrial customers, when compared with ATCO Pipelines' fully allocated cost of service tolls and investment policy. ATCO Pipelines' investment policy holds customers accountable for plant investments made on their behalf whereas NGTL's investment policy is less rigorous.

To compete with NGTL, ATCO Pipelines has relied on non-standard contracts with industrial customers. As a result of the non-standard contracts (largely with customers in the East Edmonton and Fort Saskatchewan areas), ATCO Pipelines has been able to retain much of its industrial load and therefore continue to attract producer receipts. Nevertheless, NGTL has been able to attract a significant ATCO Pipelines industrial customer. While in this particular instance, ATCO Pipelines entered into a Transportation-by-Others (TBO) arrangement with NGTL to provide this customer with the least cost transportation alternative (Decision 2005-100, August 2005), the circumstances demonstrate the ability of NGTL to attract ATCO Pipelines' existing industrial customers due to NGTL's rate structure and its ability to roll in TBO costs with its revenue requirement. Further, through the arrangement, ATCO Pipelines was required to give up exchange capability associated with this industrial customer, limiting ATCO Pipelines' ability to contract for producer receipts to match industrial load. The loss of this exchange capability, which results in more producer volumes being subject to a dual toll to access both the ATCO Pipelines and NGTL systems, is of particular concern, as it creates a higher risk that producers will seek to bypass the ATCO Pipelines system entirely.

The competition between ATCO Pipelines and NGTL for producer receipt volumes includes producers connected to the two systems and those connected solely to the ATCO Pipelines system. While competition is most intense where producers are connected to both systems, competition also exists where the producer is currently attached solely to ATCO Pipelines. In these latter circumstances, NGTL may propose to build a bypass pipeline or to contract with ATCO Pipelines for TBO service. For example, in 2005 NGTL entered into a non-standard agreement with ATCO Pipelines for service in the Grande Cache area as an alternative to building a competing pipeline extension. While the EUB approved the arrangement (Decision 2006-089, August 2006), it concluded that the specific conditions could potentially erode the benefits to ATCO Pipelines' other customers. As a result, the EUB indicated that, if the costs of the arrangement exceeded the benefits, the shareholder could be at risk for the difference between the actual costs and the projected net benefit. In early 2008, NGTL filed an application to construct pipeline facilities in the Grande Cache area, which if built, under the status quo, would likely divert ATCO Pipelines' producer receipts from its existing facilities in the area to the NGTL line. This application provides an additional illustration of the extent to which ATCO Pipelines' producer receipt volumes are potentially at risk under current industry structure in Alberta.

Competition for producer receipts can be expected to intensify as conventional supply in the Western Canadian Sedimentary Basin (WCSB) declines. The EUB's report *Alberta's Energy Reserves and Supply/Demand Outlook 2008-2017* (June 2008) concluded that WCSB gas production peaked in 2001 and conventional gas production would decline by an average of 3.2 percent per year over the forecast period. As well the National Energy Board report, *Short-term Canadian Natural Gas Deliverability 2008-2010,* indicates that, higher decline rates are forecast for areas included in the ATCO Pipelines service territory. Higher decline rates are forecast for the ATCO Pipelines service territory.

While coal-bed methane (CBM) is forecast to supplement the supply of conventional gas in the province, its development is dependent on the commodity price of natural gas. Recent prices of natural gas are not supportive of rapid development of this source of supply. In addition, NGTL has recently completed an expansion of its system facilities into the Horseshoe Canyon CBM area, further limiting the opportunities available to ATCO Pipelines. The expected decline in conventional gas production leads to higher long-term supply risk for ATCO Pipelines. While the EUB concluded in Decision 2003-100 (December 2003) that longer-term supply risk can be dealt with through accelerated depreciation or reallocation of costs should it arise,[51] that conclusion presumes that (1) in the longer term there are customers who are able to bear those costs; and (2) current regulators are able to guarantee future capital recovery. Neither of those outcomes is assured.

Under the status quo, ATCO Pipelines' unique business risk factor is the level of pipe-on-pipe competition that it faces, particularly with NGTL, but also with other regulated and unregulated pipelines. The EUB had recognized in 2002 (Decisions 2002-16 and

[51] In Decision 2004-052, the EUB acknowledged that NGTL faced potentially higher long-term risks due to supply risk, although the bulk of that risk, if it materializes, would likely be identified early enough for NGTL to apply to the EUB for potential adjustments to throughput forecasts and/or depreciation rates.

2002-058) that there were significant issues related to competition among pipelines that needed to be addressed, i.e., cost allocation, accountability for system expansion and code of conduct. In 2004, at the time of the Decision 2004-052, the major issues related to competition among pipelines had yet to be addressed. The EUB indicated that for purposes of establishing ATCO Pipeline's common equity ratio, it would not speculate on the outcome of those issues, but would set the capital structure on the basis of the business risks faced by ATCO Pipelines at the time. The EUB indicated that the Competitive Pipeline Module was the appropriate forum to deal with the inter-pipeline competition risks that confront ATCO Pipelines.

In Decision 2006-010 (Nova Gas Transmission Ltd., 2005 General Rate Application, Phase II, February 2006), the EUB reviewed NGTL's cost allocation and rate design in the context of appropriate competition among pipelines. It noted that the majority of stakeholders did not support cost-based pricing as a measure for promoting appropriate competition between ATCO Pipelines and NGTL. In approving the status quo, the EUB noted that it represented a departure from its goal of matching cost causation with cost responsibility, but concluded that significant weight had to be given to the support of the majority of interested parties for maintaining the status quo. With the status quo accepted for rate design, the EUB declined to alter NGTL's cost accountability provisions, as it viewed them as part of the pipeline's integrated rate design. In conjunction with its acceptance of NGTL's rate design, the EUB concluded that the focus of the competitive pipeline proceeding should shift from a tolls perspective to a facilities (least cost alternative) perspective.

As a result, the issues that were being dealt with in the recently suspended Competitive Pipeline Review proceeding focus on competition boundaries, the obligation to serve, and the Least Cost Alternative Policy (including TBO issues). Since rate design and investment policy issues were not part of the Competitive Pipeline Review proceeding, under the status quo, ATCO Pipelines will continue to be faced with a rate environment that inherently favours NGTL.

With respect to the issues that were being considered in the Competitive Pipeline Review proceeding, the competition boundaries issues increase the uncertainties facing ATCO Pipelines. NGTL has already applied to the EUB (October 2001) to build new pipeline capacity to provide service to existing customers of ATCO Pipelines in the Fort Saskatchewan area. While the EUB denied the application at the time, NGTL stated publicly that it still intended to find ways to serve "our Fort Saskatchewan customers and new industrial customers." (TransCanada's On-line Magazine, "Update", Summer 2002). NGTL has succeeded in part, as noted above, by attracting one of ATCO Pipelines' significant industrial customers via a TBO arrangement. Given the current and expected development in the Fort Saskatchewan area related to oil sands activity, and the natural gas requirements for these projects, it is highly likely that competition to serve new and existing customers will intensify.

In this context, in June 2008, NGTL applied to transfer regulation of the pipeline from the AUC to the NEB. If NGTL moves to NEB regulation, it would be subject to NEB policies regarding pipeline competition, while ATCO Pipelines would be subject to AUC policies and guidelines. Under the status quo, if the Competitive Pipeline Review proceeding were to recommence, ATCO Pipelines faces the risk that it would be subject to restrictions arising from the outcome that NGTL as an NEB regulated pipeline would not.

The appropriate framework for pipe-on-pipe competition in Alberta has now been at issue for at least six years. Two of ATCO Pipelines' three key issues, toll design and investment policy, have settled in favour of NGTL. The third issue, least cost alternative methodology, is being addressed in Part B of the Competitive Pipeline Review proceeding; the outcome of Parts A and B of the proceeding, in terms of regulations or guidelines, is uncertain both in substance and timing.

In summary, under the status quo, the business risks facing ATCO Pipelines are higher than at the time of the Generic Cost of Capital proceeding, primarily as a result of :

(1) the decision to maintain the status quo with respect to NGTL's rate design and investment policy, which increases ATCO Pipelines' competitive risks;

(2) the introduction of TBOs that have either restricted exchange capacity and thereby decreased ATCO Pipelines' ability to compete for producer receipts, or introduced new risks of bearing costs deemed to be in excess of the benefits to customers;

(3) increased competition for declining receipt volumes in ATCO Pipelines' service territory, and,

(4) through the indeterminate outcome, substance and timing of the "rules of the game" as regards future pipe-on-pipe competition in Alberta.

With respect to ATCO Pipelines' relative business and financial risk, the evidence of Mr. Coyne develops the cost of capital for a benchmark Alberta gas pipeline, e.g., NGTL. The cost of capital for a benchmark Alberta gas pipeline is represented by the lower end of the range of cost of capital estimates for a sample of Canadian and U.S. pipeline companies. The lower end of the range recognizes that a benchmark Canadian pipeline faces similar competitive and supply issues to U.S. pipelines, but is subject to a regulatory framework which provides, in the short-term, a higher degree of assurance that the pipeline will recover its allowed return. While ATCO faces similar short-term cost recovery risks to a benchmark pipeline like NGTL, it faces significantly higher competitive risks under the status quo, and thus faces a higher cost of capital.

The higher business risk of ATCO Pipelines relative to that of a benchmark Alberta pipeline is reasonably recognized by the differential between Mr. Coyne's benchmark Alberta pipeline cost of capital estimates (which are derived from the lower end of the ROE range at the sample common equity ratio) and the middle of the cost of capital estimates (derived from the middle of the range of ROEs at the sample common equity ratio). Within the same range of common equity ratios (40%-50%, as summarized in

Table 7 above) recommended by Mr. Coyne for a benchmark gas pipeline, the ROE for the higher risk pipeline, i.e., ATCO Pipelines, is approximately 100-120 basis points higher, as summarized in Table 10 below. In other words, at the same common equity ratios, the ROE for ATCO Pipelines would be approximately 100-120 basis points higher than for the benchmark pipeline.

**Table 10**

| **Returns on Equity and Differential Risk Premiums** | | | | | | |
|---|---|---|---|---|---|---|
| | **Coyne Recommended Range of Common Equity Ratios** | | | | | |
| | **50% (Sample Equity Ratio)** | **48%** | **46%** | **44%** | **42%** | **40%** |
| **Gas Transmission Benchmark** | 10.1% | 10.3% | 10.5% | 10.8% | 11.0% | 11.3% |
| **ATCO Pipelines** | 11.1% | 11.3% | 11.6% | 11.9% | 12.2% | 12.5% |
| **Difference** | 1.0% | 1.0% | 1.1% | 1.1% | 1.2% | 1.2% |

Source: Table 7 (McShane) and Foster Associates calculations

ATCO Pipelines is proposing to use the same common equity ratio (43%) that was adopted in the last generic cost of capital proceeding and agreed to for purposes of the 2008-2009 settlement. At a 43% common equity ratio, a 1.0-1.2% differential in ROE with the benchmark results in an ROE for ATCO Pipelines of approximately 12.0%.[52]

[52] Since ATCO Pipelines' has settled the authorized ROE for 2009, the 12% recommended ROE should be adopted as the point of departure to establish the ROE for 2010, using the automatic adjustment formula adopted by the AUC in this proceeding.

## APPENDIX A
## QUALIFICATIONS OF KATHLEEN C. McSHANE

Kathleen McShane is President of and senior consultant with Foster Associates, Inc., where she has been employed since 1981. She holds an M.B.A. degree in Finance from the University of Florida, and M.A. and B.A. degrees from the University of Rhode Island. She has been a CFA charterholder since 1989.

Ms. McShane worked for the University of Florida and its Public Utility Research Center, functioning as a research and teaching assistant, before joining Foster Associates. She taught both undergraduate and graduate classes in financial management and assisted in the preparation of a financial management textbook.

At Foster Associates, Ms. McShane has worked in the areas of financial analysis, energy economics and cost allocation. Ms. McShane has presented testimony in more than 190 proceedings on rate of return and capital structure before federal, state, provincial and territorial regulatory boards, on behalf of U.S. and Canadian gas distributors and pipelines, electric utilities and telephone companies. These testimonies include the assessment of the impact of business risk factors (e.g., competition, rate design, contractual arrangements) on capital structure and equity return requirements. She has also testified on various ratemaking issues, including deferral accounts, rate stabilization mechanisms, excess earnings accounts, cash working capital, and rate base issues. Ms. McShane has provided consulting services for numerous U.S. and Canadian companies on financial and regulatory issues, including financing, dividend policy, corporate structure, cost of capital, automatic adjustments for return on equity, form of regulation (including performance-based regulation), unbundling, corporate separations, stand-alone cost of debt, regulatory climate, income tax allowance for partnerships, change in fiscal year end, treatment of inter-corporate financial transactions, and the impact of weather normalization on risk.

Ms. McShane was principal author of a study on the applicability of alternative incentive regulation proposals to Canadian gas pipelines. She was instrumental in the design and preparation of a study of the profitability of 25 major U.S. gas pipelines, in which she developed estimates of rate base, capital structure, profit margins, unit costs of providing services, and various measures of return on investment. Other studies performed by Ms. McShane include a comparison of municipal and privately owned gas utilities, an analysis of the appropriate capitalization and financing for a new gas pipeline, risk/return analyses of proposed water and gas distribution companies and an independent power project, pros and cons of performance-based regulation, and a study on pricing of a competitive product for the U.S. Postal Service. She has also conducted seminars on cost of capital for regulated utilities, with focus on the Canadian regulatory arena.

**Publications, Papers and Presentations**

- *Utility Cost of Capital: Canada vs. U.S.,* presented at the CAMPUT Conference, May 2003.

- *The Effects of Unbundling on a Utility's Risk Profile and Rate of Return*, (co-authored with Owen Edmondson, Vice President of ATCO Electric), presented at the Unbundling Rates Conference, New Orleans, Louisiana sponsored by Infocast, January 2000.

- *Atlanta Gas Light's Unbundling Proposal: More Unbundling Required?* presented at the 24th Annual Rate Symposium, Kansas City, Missouri, sponsored by several commissions and universities, April 1998.

- *Incentive Regulation: An Alternative to Assessing LDC Performance*, (co-authored with Dr. William G. Foster), presented at the Natural Gas Conference, Chicago, Illinois sponsored by the Center for Regulatory Studies, May 1993.

- *Alternative Regulatory Incentive Mechanisms*, (co-authored with Stephen F. Sherwin), prepared for the National Energy Board, Incentive Regulation Workshop, October 1992.

**EXPERT TESTIMONY/OPINIONS**

**ON**

**RATE OF RETURN AND CAPITAL STRUCTURE**

| Client | Date |
|---|---|
| Alberta Natural Gas | 1994 |
| AltaGas Utilities | 2000 |
| Ameren (Central Illinois Public Service) | 2000, 2002, 2005, 2007 (2 cases) |
| Ameren (Central Illinois Light Company) | 2005, 2007 (2 cases) |
| Ameren (Illinois Power) | 2004, 2005, 2007 (2 cases) |
| Ameren (Union Electric) | 2000 (2 cases), 2002 (2 cases), 2003, 2006 (2 cases) |
| ATCO Electric | 1989, 1991, 1993, 1995, 1998, 1999, 2000, 2003 |
| ATCO Gas | 2000, 2003, 2007 |
| ATCO Pipelines | 2000, 2003, 2007 |
| Bell Canada | 1987, 1993 |
| Benchmark Utility Cost of Equity (British Columbia) | 1999 |
| Canadian Western Natural Gas | 1989, 1996, 1998, 1999 |
| Centra Gas B.C. | 1992, 1995, 1996, 2002 |
| Centra Gas Ontario | 1990, 1991, 1993, 1994, 1995 |
| Direct Energy Regulated Services | 2005 |
| Dow Pool A Joint Venture | 1992 |
| Edmonton Water/EPCOR Water Services | 1994, 2000, 2006, 2008 |
| Enbridge Gas Distribution | 1988, 1989, 1991-1997, 2001, 2002 |
| Enbridge Gas New Brunswick | 2000 |
| Enbridge Pipelines (Line 9) | 2007 |
| Enbridge Pipelines (Southern Lights) | 2007 |
| FortisBC | 1995, 1999, 2001, 2004 |
| Gas Company of Hawaii | 2000, 2008 |
| Gaz Metropolitain | 1988 |
| Gazifère | 1993, 1994, 1995, 1996, 1997, 1998 |

| | |
|---|---|
| Generic Cost of Capital, Alberta (ATCO and AltaGas Utilities) | 2003 |
| Heritage Gas | 2004 |
| Hydro One | 1999, 2001, 2006 (2 cases) |
| Insurance Bureau of Canada (Newfoundland) | 2004 |
| Laclede Gas Company | 1998, 1999, 2001, 2002, 2005 |
| Laclede Pipeline | 2006 |
| Mackenzie Valley Pipeline | 2005 |
| Maritimes NRG (Nova Scotia) and (New Brunswick) | 1999 |
| Multi-Pipeline Cost of Capital Hearing (National Energy Board) | 1994 |
| Natural Resource Gas | 1994, 1997, 2006 |
| New Brunswick Power Distribution | 2005 |
| Newfoundland & Labrador Hydro | 2001, 2003 |
| Newfoundland Power | 1998, 2002, 2007 |
| Newfoundland Telephone | 1992 |
| Northland Utilities | 2008 (2 cases) |
| Northwestel, Inc. | 2000, 2006 |
| Northwestern Utilities | 1987, 1990 |
| Northwest Territories Power Corp. | 1990, 1992, 1993, 1995, 2001, 2006 |
| Nova Scotia Power Inc. | 2001, 2002, 2005, 2008 |
| Ontario Power Generation | 2007 |
| Ozark Gas Transmission | 2000 |
| Pacific Northern Gas | 1990, 1991, 1994, 1997, 1999, 2001, 2005 |
| Plateau Pipe Line Ltd. | 2007 |
| Platte Pipeline Co. | 2002 |
| St. Lawrence Gas | 1997, 2002 |
| Southern Union Gas | 1990, 1991, 1993 |
| Stentor | 1997 |
| Tecumseh Gas Storage | 1989, 1990 |
| Telus Québec | 2001 |
| Terasen Gas | 1992, 1994, 2005 |
| Terasen Gas (Whistler) | 2008 |

| | |
|---|---|
| TransCanada PipeLines | 1988, 1989, 1991 (2 cases), 1992, 1993 |
| TransGas and SaskEnergy LDC | 1995 |
| Trans Québec & Maritimes Pipeline | 1987 |
| Union Gas | 1988, 1989, 1990, 1992, 1994, 1996, 1998, 2001 |
| Westcoast Energy | 1989, 1990, 1992 (2 cases), 1993, 2005 |
| Yukon Electrical Company | 1991, 1993, 2008 |
| Yukon Energy | 1991 1993 |

**EXPERT TESTIMONY/OPINIONS**

**ON**

**OTHER ISSUES**

| Client | Issue | Date |
|---|---|---|
| New Brunswick Power Distribution | Interest Coverage/Capital Structure | 2007 |
| Heritage Gas | Revenue Deficiency Account | 2006 |
| Hydro Québec | Cash Working Capital | 2005 |
| Nova Scotia Power | Cash Working Capital | 2005 |
| Ontario Electricity Distributors | Stand-Alone Income Taxes | 2005 |
| Caisse Centrale de Réassurance | Collateral Damages | 2004 |
| Hydro Québec | Cost of Debt | 2004 |
| Enbridge Gas New Brunswick | AFUDC | 2004 |
| Heritage Gas | Deferral Accounts | 2004 |
| ATCO Electric | Carrying Costs on Deferral Account | 2001 |
| Newfoundland & Labrador Hydro | Rate Base, Cash Working Capital | 2001 |
| Gazifère Inc. | Cash Working Capital | 2000 |
| Maritime Electric | Rate Subsidies | 2000 |
| Enbridge Gas Distribution | Principles of Cost Allocation | 1998 |
| Enbridge Gas Distribution | Unbundling/Regulatory Compact | 1998 |
| Maritime Electric | Form of Regulation | 1995 |
| Northwest Territories Power | Rate Stabilization Fund | 1995 |
| Canadian Western Natural Gas | Cash Working Capital/Compounding Effect | 1989 |
| Gaz Metro/ Province of Québec | Cost Allocation/Incremental vs. Rolled-In Tolling | 1984 |

**FINANCIAL METRICS**
**FOR CANADIAN UTILITIES WITH RATED DEBT**
**2005-2007**

| Company | EBIT Coverage | FFO/ Total Debt | FFO Coverage [1/] |
|---|---|---|---|
| **Electric Utilities** | | | |
| AltaLink L.P. | 1.9 | 12.6 | 3.1 |
| CU Inc. | 2.5 | 17.1 | 3.4 |
| Enersource | 2.2 | 14.9 | 3.2 |
| ENMAX Corp. | 8.2 | 18.0 | 3.9 |
| EPCOR Utilities Inc. | 2.8 | 20.3 | 3.6 |
| FortisAlberta Inc. | 2.2 | 14.3 | 4.2 |
| FortisBC Inc. | 2.1 | 10.4 | 2.7 |
| Hamilton Utilities | 3.2 | 32.2 | 4.9 |
| Hydro One Inc. | 2.8 | 14.5 | 3.4 |
| Hydro Ottawa Holding Inc. | 3.5 | 22.3 | 5.3 |
| London Hydro | 2.9 | 20.9 | 4.0 |
| Maritime Electric | 2.7 | 13.5 | 2.8 |
| Newfoundland Power | 2.3 | 14.1 | 2.7 |
| Nova Scotia Power | 2.5 | 13.8 | 3.4 |
| Toronto Hydro | 2.3 | 17.7 | 3.5 |
| Veridian | 3.4 | na | na |
| **Gas Distributors** | | | |
| Enbridge Gas Distribution | 2.1 | 11.5 | 2.6 |
| Gaz Metropolitain | 2.5 | 20.9 | 5.0 |
| Pacific Northern Gas | 2.4 | 12.5 | 2.5 |
| Terasen Gas | 2.0 | 9.1 | 2.4 |
| Union Gas | 2.1 | 12.4 | 2.8 |
| **Pipelines** | | | |
| Enbridge Pipelines | 3.3 | 16.9 | 3.5 |
| Nova Gas Transmission Ltd. | 2.4 | 19.0 | 3.2 |
| Trans Quebec & Maritimes | 2.4 | 10.4 | 2.7 |
| TransCanada PipeLines Ltd. | 2.5 | 14.3 | 2.8 |
| Westcoast Energy Inc. | 2.2 | 17.0 | 3.2 |
| **Medians** | | | |
| **Electric T&D** | **2.8** | **16.3** | **3.7** |
| **Electric Integrated** | **2.5** | **13.8** | **3.4** |
| **All Electric** | **2.6** | **14.9** | **3.4** |
| **Gas Distributors** | **2.1** | **12.4** | **2.6** |
| **Pipelines** | **2.4** | **16.9** | **3.2** |
| **All Companies** | **2.4** | **14.5** | **3.2** |

[1/] S&P defines Funds from Operations as follows:
FFO = (income from continuing operations + depreciation & amortization + deferred income taxes – AFUDC).

Source: Annual Reports to Shareholders, DBRS and Standard and Poor's

## CAPITAL STRUCTURE RATIOS
## OF CANADIAN UTILITIES WITH RATED DEBT
## (2007)

| | Long-Term Debt [1/] | Short-Term Debt | Preferred Stock [2/] | Common Stock Equity [3/] |
|---|---|---|---|---|
| **Electric Utilities** | | | | |
| Altalink LP | 61.9% | 0.0% | 0.0% | 38.1% |
| CU Inc | 56.1% | 0.0% | 5.6% | 38.2% |
| Enersource | 57.5% | 0.0% | 0.0% | 42.5% |
| ENMAX Corp. | 22.2% | 1.9% | 0.0% | 75.9% |
| EPCOR Utilities Inc. | 44.9% | 2.9% | 2.6% | 49.7% |
| FortisAlberta | 57.5% | 0.8% | 0.0% | 41.8% |
| FortisBC | 59.9% | 0.0% | 0.0% | 40.1% |
| Hamilton Utilities | 35.4% | 0.0% | 0.0% | 64.6% |
| Hydro One Inc. | 53.4% | 0.1% | 3.1% | 43.5% |
| Hydro Ottawa Holding Inc. | 43.8% | 4.3% | 0.0% | 51.9% |
| London Hydro | 36.5% | 0.0% | 0.0% | 63.5% |
| Maritime Electric | 34.7% | 25.2% | 0.0% | 40.1% |
| Newfoundland Power | 54.8% | 0.0% | 1.2% | 44.1% |
| Nova Scotia Power | 53.3% | 1.0% | 9.7% | 36.0% |
| Toronto Hydro | 56.5% | 0.0% | 0.0% | 43.5% |
| Veridian | 40.4% | 0.0% | 0.0% | 59.6% |
| **Gas Distributors** | | | | |
| Enbridge Gas Distribution | 48.9% | 11.6% | 2.1% | 37.4% |
| Gaz Metro | 63.2% | 1.6% | 0.0% | 35.2% |
| Pacific Northern Gas | 44.1% | 5.3% | 2.9% | 47.7% |
| Terasen Gas | 53.1% | 12.1% | 0.0% | 34.8% |
| Union Gas | 51.7% | 9.8% | 2.8% | 35.6% |
| **Pipelines** | | | | |
| Enbridge Pipelines | 36.5% | 16.7% | 0.0% | 46.9% |
| Nova Gas Transmission Ltd. | 56.2% | 1.9% | 0.0% | 41.9% |
| Trans Quebec & Maritimes | 69.8% | 0.0% | 0.0% | 30.2% |
| TransCanada Pipelines | 58.0% | 0.2% | 1.5% | 40.3% |
| Westcoast Energy | 48.8% | 2.3% | 5.1% | 43.8% |
| **Medians** | | | | |
| **Electric T&D** | **53.4%** | **0.0%** | **0.0%** | **44.1%** |
| **Electric Integrated** | **53.3%** | **1.0%** | **2.6%** | **40.1%** |
| **All Electric** | **53.3%** | **0.0%** | **0.0%** | **43.5%** |
| **Gas Distributors** | **51.7%** | **9.8%** | **2.1%** | **35.6%** |
| **Pipelines** | **56.2%** | **1.9%** | **0.0%** | **41.9%** |
| **All Companies** | **53.2%** | **0.9%** | **0.0%** | **42.2%** |

1/ Includes current portion of long-term debt and preferred securities classified as debt.
2/ Includes minority interest in preferred shares of subsidiary companies and preferred securities .
3/ Includes minority interest in common shares of subsidiary companies.

**DEBT AND COMMON STOCK QUALITY RATINGS**
**OF CANADIAN UTILITIES**

| Company | Debt Rated | DBRS Bond Rating | Moody's Bond Rating | S&P Bond Rating | CBS Stock Ranking |
|---|---|---|---|---|---|
| **Electric Utilities** | | | | | |
| AltaLink L.P. | Senior Secured | A | | A- | |
| CU Inc. | Senior Unsecured | A(high) | | A | Very conservative |
| Enersource | Issuer | A | | | |
| ENMAX | Unsecured Debentures (DBRS) | A(low) | | BBB+ | |
| EPCOR Utilities Inc | Senior Unsecured | A(low) | | BBB+ | |
| FortisAlberta Inc. | Senior Unsecured | A(low) | Baa1 | A- | Very conservative |
| FortisBC Inc | Secured Debentures | BBB(high) | Baa2 | | Very conservative |
| Hamilton Utilities | Senior Unsecured | | | A+ | |
| Hydro One | Senior Unsecured | A(high) | Aa3 | A+ | |
| Hydro Ottawa Holding Inc. | Senior Unsecured | A(low) | | A | |
| London Hydro | Issuer | | | A | |
| Maritime Electric | Senior Secured | | | A | Very conservative |
| Newfoundland Power | Senior Secured | A | Baa1 | NR [1/] | Very conservative |
| Nova Scotia Power | Senior Unsecured | A(low) | Baa1 | BBB | Very conservative |
| Toronto Hydro | Senior Unsecured | A | | A | |
| Veridian | Issuer | A | | | |
| **Gas Distributors** | | | | | |
| Enbridge Gas Distribution | Senior Unsecured | A | | A- | Very conservative |
| Gaz Metropolitain | Senior Secured | A | | A | |
| Pacific Northern Gas | Senior Secured | BBB(low) | | NR [2/] | Average |
| Terasen Gas | Senior Secured | A | A2 | AA- | |
| | Senior Unsecured | A | A3 | A | |
| Union Gas Limited | Senior Unsecured | A | | BBB+ | |
| **Pipelines** | | | | | |
| Enbridge Pipelines | Senior Unsecured | A(high) | | A- | Very conservative |
| NOVA Gas Transmission | Senior Unsecured | A | A3 | A- | Very conservative |
| Trans Quebec & Maritimes | Senior Unsecured | A(low) | | BBB+ | |
| TransCanada PipeLines | Senior Unsecured | A | A3 | A- | Very conservative |
| Westcoast Energy | Senior Unsecured | A(low) | | BBB+ | |
| **Medians** | | | | | |
| **Electric T&D** | | **A** | **Baa1** | **A** | **Very conservative** |
| **Electric Integrated** | | **A(low)** | **Baa2** | **A-** | **Very conservative** |
| **All Electric** | | **A(low)** | **Baa1** | **A** | **Very conservative** |
| **Gas Distributors** | | **A** | **A3** | **A** | **Very conservative** |
| **Pipelines** | | **A** | **A3** | **A-** | **Very conservative** |
| **All Companies** | | **A** | **A3** | **A-** | **Very conservative** |

[1/] Withdrawn by company; BBB+ prior to withdrawal.
[2/] Withdrawn by company; BBB- prior to withdrawal.

Note: Debt ratings are for utility; Stock rankings are for parent.

Source: DBRS Bond Ratings, Moodys.com, Standard & Poor's, The Blue Book of CBS Stock Reports.

**DEBT RATINGS AND FINANCIAL METRICS FOR U.S. ELECTRIC UTILITIES RATED A- or HIGHER**

| | S&P | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Average 2005-2007 [1/] | | | | | | |
| Name | Debt Rating | Business Profile | Financial Profile | Debt Ratio | EBIT Coverage | FFO/Debt | FFO Coverage | Moody's Debt Rating | Common Equity Ratio (2007) [2/] | Average ROE 2005-2007 |
| Alabama Power Co. | A | Excellent | Intermediate | 52.7 | 4.2 | 21.8 | 5.3 | A2 | 43.0 | 13.3 |
| Central Hudson Gas & Electric Corp. | A | Excellent | Intermediate | 61.4 | 4.5 | 16.1 | 4.5 | A2 | 42.6 | 10.9 |
| Consolidated Edison Co. of New York Inc. | A- | Excellent | Intermediate | 54.1 | 3.0 | 15.5 | 3.6 | A1 | 49.5 | 10.8 |
| Consolidated Edison Inc. | A- | Excellent | Intermediate | 57.1 | 2.9 | 14.7 | 3.6 | A2 | 48.9 | 10.2 |
| Duke Energy Carolinas LLC | A- | Excellent | Intermediate | 47.9 | 4.1 | 31.3 | 9.9 | A3 | na | na |
| Duke Energy Corp. | A- | Excellent | Intermediate | 44.3 | 3.6 | 22.4 | 4.5 | Baa2 | 64.3 | 8.7 |
| Duke Energy Indiana Inc. | A- | Excellent | Intermediate | 55.0 | 3.1 | 17.4 | 4.4 | Baa1 | na | 9.1 |
| Duke Energy Ohio Inc. | A- | Excellent | Intermediate | 69.0 | 1.3 | 8.2 | 2.7 | Baa1 | na | 7.9 |
| Florida Power & Light Co. | A | Excellent | Intermediate | 32.1 | 3.9 | 24.0 | 5.4 | A1 | 54.6 | 11.4 |
| FPL Group Inc. | A | Excellent | Intermediate | 51.4 | 2.9 | 25.8 | 5.3 | A2 | 43.9 | 12.5 |
| Georgia Power Co. | A | Excellent | Intermediate | 49.7 | 4.8 | 23.3 | 5.5 | A2 | 47.5 | 13.9 |
| Gulf Power Co. | A | Excellent | Intermediate | 53.2 | 3.8 | 20.1 | 4.6 | A2 | 45.3 | 12.4 |
| Integrys Energy Group Inc | A- | Strong | Intermediate | 52.6 | 2.8 | 12.4 | 3.3 | A3 | 53.3 | 11.6 |
| Madison Gas & Electric Co. | AA- | Excellent | Intermediate | 50.8 | 4.6 | 20.5 | 5.4 | Aa3 | 50.5 | 10.5 |
| MidAmerican Energy Co. | A- | Excellent | Aggressive | 53.0 | 4.2 | 23.3 | 5.3 | A2 | 46.9 | 14.4 |
| MidAmerican Energy Holdings Co. | A- | Excellent | Aggressive | 66.1 | 2.3 | 13.0 | 3.0 | Baa1 | 32.0 | 15.8 |
| Mississippi Power Co. | A | Excellent | Intermediate | 47.0 | 6.9 | 44.7 | 11.3 | A1 | 65.3 | 13.8 |
| Northern States Power (Wisconsin) | A- | Excellent | Intermediate | 44.9 | 3.4 | 24.0 | 4.9 | A3 | 55.4 | 30.1 |
| NSTAR | A+ | Excellent | Intermediate | 62.4 | 3.5 | 23.2 | 5.3 | A2 | 35.9 | 13.3 |
| Orange and Rockland Utilities Inc. 3/ | A- | Excellent | Intermediate | 70.8 | 3.6 | 16.9 | 3.9 | A2 | na | 13.2 |
| PacifiCorp | A- | Excellent | Aggressive | 55.6 | 2.8 | 16.8 | 3.8 | Baa1 | 49.2 | 7.6 |
| PPL Electric Utilities Corp. | A- | Excellent | Aggressive | 52.3 | 3.4 | 20.4 | 4.1 | Baa1 | 38.9 | 12.2 |
| San Diego Gas & Electric Co. | A | Excellent | Intermediate | 51.5 | 3.4 | 30.5 | 4.6 | A2 | 51.8 | 15.5 |
| SCANA Corp. | A- | Excellent | Aggressive | 57.5 | 2.4 | 19.6 | 4.3 | Baa1 | 43.5 | 11.5 |
| South Carolina Electric & Gas Co. | A- | Excellent | Aggressive | 49.1 | 2.6 | 27.3 | 5.3 | A3 | 50.3 | 9.9 |
| Southern Co. | A | Excellent | Intermediate | 56.4 | 3.6 | 21.3 | 5.1 | A3 | 41.4 | 14.7 |
| Wisconsin Electric Power Co. | A- | Excellent | Intermediate | 46.4 | 3.7 | 28.3 | 5.3 | A1 | 52.8 | 11.7 |
| Wisconsin Power & Light Co. | A- | Excellent | Intermediate | 50.8 | 3.8 | 20.2 | 4.8 | A2 | 54.8 | 9.8 |
| Wisconsin Public Service Corp. | A | Excellent | Intermediate | 55.5 | 3.1 | 18.7 | 4.1 | A1 | 56.9 | 9.3 |
| **Mean** | **A** | **Excellent** | **Intermediate** | **53.5** | **3.5** | **21.4** | **4.9** | **A2** | **48.7** | **12.4** |
| **Median** | **A** | **Excellent** | **Intermediate** | **52.7** | **3.5** | **20.5** | **4.6** | **A2** | **49.2** | **11.6** |

[1/] S&P Credit Stats

[2/] Equity Ratio and ROE data from S&P's Research Insight. Equity ratio calculated as Common Equity / (Common Equity, Long Term Debt, Short Term Debt, Preferred Stock).

[3/] Data 2004-2006 latest available in Credit Stats

Source: S&P: Research Insight; *Issuer Ranking: U.S. Integrated Electric Utility Companies, Strongest to Weakest,* November 4, 2008;
*Issuer Ranking: U.S. Natural Gas Distributors and Integrated Gas Companies, Strongest to Weakest,* September 23, 2008; and S&P, *Credit Stats,* September 2008.

**DEBT RATINGS AND FINANCIAL METRICS FOR U.S. NATURAL GAS UTILITIES RATED A- OR HIGHER**

| | S&P | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Average 2005-2007 [1/] | | | | | | |
| **Name** | **Debt Rating** | **Business Profile** | **Financial Profile** | **Debt Ratio** | **EBIT Coverage** | **FFO/Debt** | **FFO Coverage** | **Moody's Debt Rating** | **Common Equity Ratio (2007)** [2/] | **Average ROE 2005-2007** |
| AGL Resources Inc. | A- | Excellent | Intermediate | 58.2 | 3.7 | 19.6 | 4.4 | A3 | 42.4 | 13.3 |
| Indiana Gas Co. Inc. (owned by Vectren) | A- | Excellent | Intermediate | 48.0 | 2.8 | 16.4 | 3.6 | Baa1 | na | na |
| Laclede Gas Co. | A | Excellent | Intermediate | 60.0 | 2.3 | 13.8 | 3.1 | Baa1 | 41.3 | 9.1 |
| Nicor Inc. | AA | Excellent | Intermediate | 45.3 | 3.9 | 28.3 | 6.0 | A3 | 52.1 | 15.9 |
| Nicor Gas | AA | Excellent | Intermediate | 47.1 | 2.7 | 19.7 | 4.7 | na | na | na |
| Northwest Natural Gas Co. | AA- | Excellent | Intermediate | 53.4 | 3.6 | 21.2 | 4.4 | A3 | 47.4 | 11.1 |
| Piedmont Natural Gas Co. Inc. | A | Excellent | Intermediate | 50.5 | 3.9 | 24.9 | 4.9 | A3 | 46.3 | 11.5 |
| Questar Gas Co. | A- | Excellent | Intermediate | 51.9 | 3.5 | 22.7 | 4.4 | A3 | 46.9 | 11.3 |
| San Diego Gas & Electric Co. | A | Excellent | Intermediate | 51.5 | 3.4 | 30.5 | 4.6 | A2 | 51.8 | 15.5 |
| Southern California Gas Co. | A | Excellent | Intermediate | 56.2 | 4.6 | 30.6 | 6.4 | A2 | 52.6 | 15.5 |
| Vectren Corp. | A- | Excellent | Intermediate | 58.4 | 2.8 | 17.1 | 4.0 | na | 40.6 | 11.2 |
| Vectren Utility Holdings Inc. | A- | Excellent | Intermediate | 53.7 | 2.9 | 19.0 | 4.1 | Baa1 | 42.9 | 9.4 |
| Washington Gas Light Co. | AA- | Excellent | Intermediate | 50.8 | 4.6 | 24.1 | 5.5 | A2 | 53.0 | 10.3 |
| WGL Holdings Inc. | AA- | Excellent | Intermediate | 52.8 | 4.6 | 22.2 | 5.3 | na | 53.6 | 10.9 |
| **Mean** | **A** | **Excellent** | **Intermediate** | **52.7** | **3.5** | **22.2** | **4.7** | **A3** | **47.6** | **12.1** |
| **Median** | **A** | **Excellent** | **Intermediate** | **52.4** | **3.6** | **21.7** | **4.5** | **A3** | **47.1** | **11.2** |

[1/] S&P Credit Stats

[2/] Equity Ratio and ROE data from S&P's Research Insight. Equity ratio calculated as Common Equity / (Common Equity, Long Term Debt, Short Term Debt, Preferred Stock).

Source: S&P: *Issuer Ranking: U.S. Natural Gas Distributors and Integrated Gas Companies, Strongest to Weakest, September 23, 2008* and S&P, Credit Stats, September 2008.

# Alberta Utilities Commission
# 2009 Generic Cost of Capital Proceeding

**Testimony of Kathleen McShane**
**May 4, 2009**

**ALBERTA UTILITIES COMMISSION**
**2009 GENERIC COST OF CAPITAL PROCEEDING**
**Application No. 1578571 / Proceeding ID. 85**

ON BEHALF OF THE

**ATCO UTILITIES**

**(ATCO ELECTRIC LTD., ATCO GAS AND ATCO PIPELINES)**

Rebuttal Testimony
of


**KATHLEEN C. McSHANE**

**FOSTER ASSOCIATES, INC.**


Submitted: May 4, 2009

TABLE OF CONTENTS

I. INTRODUCTION ........................................................................................... 3

II. RESPONSE TO DRS. KRYZANOWSKI AND ROBERTS AND MR. MARCUS ... 3

A. Capital Structure Recommendations 3
B. Reliance on Capital Structures of Other Canadian Utilities 5
C. Relevance of Ontario Power Generation as Benchmark 8
D. Incentive to Maximize Debt 10
E. Views of Debt Rating Agencies on Levels of Deemed Equity Ratios 11
F. Allowed versus Earned ROEs and Relevance to Capital Structure 13
G. Higher Cost of Capital to BBB Rated Utilities 15
H. Interest Coverage Analysis 22
I. Business Risk 27

III. RESPONSE TO CAPP, DR. BOOTH AND DR. SAFIR ...................................... 39

A. Capital Structure Recommendations of Dr. Booth 39
B. Impact of Deferral Accounts on Risk 40
C. Dr. Booth's Recommended Capital Structure for ATCO Gas 43
D. Dr. Booth's Recommended Capital Structure for ATCO Pipelines 44

## I. INTRODUCTION

**Q1. Please state your name and business address.**

**A1.** My name is Kathleen C. McShane. My business address is Foster Associates Inc., 4550 Montgomery Avenue, Bethesda, Maryland 20814.

**Q2. What is the purpose of your rebuttal testimony?**

**A2.** The purpose of my testimony is to respond to business risk and capital structure issues raised in the evidence of Drs. Lawrence Kryzanowski and Gordon Roberts and Mr. Marcus on behalf of the UCA, the evidence of Dr. Laurence Booth on behalf of CAPP and the City of Calgary, and the evidence of Dr. Safir on behalf of CAPP. I will deal with the evidence of the witnesses in that order.

## II. RESPONSE TO DRS. KRYZANOWSKI AND ROBERTS AND MR. MARCUS

### A. Capital Structure Recommendations

**Q3. Drs. Kryzanowski and Roberts recommend common equity ratios for the ATCO Utilities of 33% for ATCO Electric Transmission, 35% for ATCO Electric Distribution, 34% for ATCO Gas and 42% for ATCO Pipelines (assuming the status quo as regards the operating environment of ATCO Pipelines). How would you characterize these recommendations?**

**A3.** In every case, Drs. Kryzanowski and Roberts have recommended a reduction in the common equity ratio to levels, which, if adopted, would result in equity ratios which are out of line not only with their U.S. peers, but also with their Canadian peers. The recommended reductions appear intent upon imposing the lowest equity ratio which could possibly be justified.

**Q4. Is setting the lowest possible equity ratio a reasonable objective?**

**A4.** No. The National Energy Board recognized that this was not a reasonable objective in its RH-2-94 *Reasons for Decision* when it stated, "Contrary to what some parties advocated during the hearing, the Board is of the view that it is not appropriate to over-leverage a pipeline in order to identify the minimum acceptable deemed common equity ratio possible." (page 25) The British Columbia Utilities Commission echoed this conclusion in its 2006 Decision (*In The Matter Of Terasen Gas Inc. And Terasen Gas (Vancouver Island) Inc. Application To Determine The Appropriate Return On Equity And Capital Structure And To Review And Revise The Automatic Adjustment Mechanism*, March 2006, page 8) when it stated, "As for the JIESC's lowest cost argument, the Commission Panel shares the view of the NEB, which recognized that 'lowest possible' was not the appropriate test", then quoted page 25 of the NEB's RH-2-94 decision.

**Q5. Drs. Kryzanowski and Roberts make very precise recommendations for the capital structures that the AUC should adopt. How does their approach compare to the approach recently accepted by the National Energy Board in RH-1-2008 (March 19, 2009)?**

**A5.** It is at odds with the NEB's TQM decision. That decision concluded that it should be up to the company to choose its optimal capital structure, which is consistent with its goal-oriented approach to regulation and with the stand-alone principle. The NEB's conclusions are consistent with the conclusions in my direct evidence in this proceeding, that is, within a reasonable range, the capital structure for a particular utility is appropriately a decision for management, because management is in the best position to assess its business risks, financing requirements and access to debt and equity capital. (page 4)

**Q6. Drs. Kryzanowski and Roberts say that they have taken the trade-off theory approach in recommending what are very precise as well as low common equity ratios for each of the ATCO Utilities. Have the witnesses taken account of the specific factors which have changed since the last generic proceeding in applying the trade-off theory?**

**A6.** No. In Appendix 2.A "Recent Thinking and Practice on Capital Structure", Drs. Kryzanowski and Roberts describe the trade-off theory as the determination of a target optimal capital structure by balancing the tax-reduction benefits of debt against the expected costs of financial distress and loss of financial flexibility.

Since the last generic cost of capital proceeding, the combined provincial/federal income tax rate has declined from the 33.87% cited by the EUB in Decision 2004-052 to 29% in 2009. The corporate tax rate will decline further, to 25% by 2012. The significant reduction in income tax rates has reduced the tax reduction benefits of debt. The onset of turmoil in the capital markets starting in 2007 and continuing through mid-2009 has reduced the Alberta utilities' financial flexibility. Despite both the lower tax-reduction benefits of debt and loss of financial flexibility, Drs. Kryzanowski and Roberts have recommended a reduction to the currently allowed common equity ratio for 10 of the 12 applicants in this proceeding. As a result, the witnesses have failed to properly apply the trade-off theory.

### B. Reliance on Capital Structures of Other Canadian Utilities

**Q7. Drs. Kryzanowski and Roberts place significant weight on the capital structures deemed by Canadian regulators for other Canadian utilities in validating their proposed equity ratios (pages 118-122). Is there an inherent problem with relying on the deemed structures of other utilities for this purpose?**

**A7.** Yes. Because the deemed capital structures reflect what regulators have allowed, versus what the companies would have chosen themselves had they been given more discretion to do so, the comparison to other allowed capital structures of Canadian utilities becomes a circular exercise. This circularity extends to comparisons with the actual capital structures of other Canadian utilities. Utilities with deemed capital structures will tend to conform their actual capital structures to the deemed levels, as there is no economic incentive to commit more equity to the capital structure than the regulator allows for regulatory purposes. Indeed, the Alberta utilities are expected to actually fund the deemed common equity ratios that are adopted by the regulator. Moreover, if the returns on equity allowed are perceived as too low, there is a built-in incentive to decrease the amount of equity committed to the utility, as it makes no economic sense for equity investors to put up incremental capital to earn an inadequate return.

**Q8. How do Drs. Kryzanowski and Roberts's recommendations comport with the conclusions of the debt rating agencies with respect to the prevailing debt ratios of Canadian utilities?**

**A8.** As discussed in my direct testimony, both DBRS and Standard & Poor's have expressed concern with the low levels of both the deemed common equity ratios and the returns on equity. For example, as I noted in my direct testimony (pages 27-28), DBRS stated with respect to FortisAlberta:

> *In Alberta, as well as in many other jurisdictions in Canada, the rates of return and equity capitalization for ratemaking purposes allowed by regulators have been low in recent years, largely as a result of the low interest rate environment. This has had a negative impact on earnings and cash flows. FortisAlberta's equity thickness at 37% and low ROE's directly impact shareholder returns, hindering the ability to attract capital for capital expenditure purposes. In addition, the allowed ROEs are significantly below those allowed for similar operations in the U.S. This acts as a disincentive for investors to allocate capital to Canadian utilities because they can earn higher rates of return in the U.S. from businesses*

> *having similar business risk profiles. (DBRS, Credit Rating Report: FortisAlberta, November 25, 2005).*

S&P considers that Canadian utility financial policies tend to be aggressive with leverage, and regulators "parsimonious" with returns.[1]

The adoption of Drs. Kryzanowski and Roberts's recommendations would cause capital structures which are already considered by the ratings agencies to be weak or aggressive to deteriorate further.

**Q9. Have Drs. Kryzanowski and Roberts given any consideration to the capital structures maintained by the Alberta utilities' U.S. peers in their comparative analysis?**

**A9.** No. Their comparisons are strictly limited to other Canadian utilities. This limitation is problematic for at least two reasons. First, as noted above, the circularity is particularly problematic when the preponderance of Canadian utilities' capital structures is more reflective of regulatory directives than management decision. Second, ignoring relevant U.S. comparables (who do have more discretion on their choice of capital structure) results in a failure to satisfy the comparable investment return standard.[2] It is puzzling that Drs. Roberts and Kryzanowski ignore U.S. comparables given their insistence that Canadian utilities could be rated BBB and access the U.S. debt markets (page 227).

[1] Standard & Poor's, *Industry Report Card: Regulatory Rulings, M&A, and Fuel Cost Recovery Dominate Global Utilities Credit Environment*, November 21, 2006.

[2] At pages 40-58 of his direct evidence on behalf of the ATCO Utilities, Mr. Coyne assesses the comparability of U.S. and Canadian utilities and concludes that that they are comparable. He also cites other studies at page 11 of his direct evidence that arrived at the same conclusion, including a study performed by Concentric Energy Advisors at the request of the Ontario Energy Board. In his rebuttal testimony, Mr. Coyne cites an additional study prepared by Concentric Energy Advisors on behalf of Hydro One and the Coalition of Large Distributors which addressed the comparability of U.S. and Canadian electric utilities and which similarly established the similarity of risks.

**Q10. What has been the average common equity ratio adopted for U.S. utilities which are of comparable business risk to Canadian utilities?**

**A10.** The average common equity ratio adopted by U.S. state regulators for gas utilities since the beginning of 2007 was 49% and for electric distribution utilities 48% (in conjunction with ROEs of 10.3% and 10.4% respectively). The equity ratios which have been adopted by the Federal Energy Regulatory Commission for electric transmission utilities have been approximately 50% in conjunction with an average ROE of 11.1% (before incentives; including incentives, the allowed ROE has been approximately 12.1%).

By comparison, the average allowed common equity ratio for Canadian utilities cited by Drs. Kryzanowski and Roberts was only 39%. The allowed common equity ratios for Canadian utilities have been materially lower than their U.S. peers. Moreover, as indicated above, the allowed ROEs for U.S. gas and electric distribution utilities have been materially higher than those of Canadian utilities, whose allowed ROEs have been approximately 8.7% since 2007.

Drs. Kryzanowski's and Roberts's recommended equity ratios of 33% (for ATCO Electric Transmission), 34% for ATCO Gas, 35% for ATCO Electric Distribution and 42% for ATCO Pipelines at the status quo in conjunction with a recommended ROE for all the Alberta utilities of 7.9% results in an overall return to each of the ATCO Utilities which falls well below the fair return standard.

## C. Relevance of Ontario Power Generation as Benchmark

**Q11. Drs. Kryzanowski and Roberts use the common equity ratio of 47% established by the Ontario Energy Board for Ontario Power Generation (OPG) as the upper end of the range for their recommendations in this proceeding (page 121). Do you agree that the OEB's finding with respect to**

**OPG is an appropriate marker for the upper end of the range for the Alberta utilities generally and the ATCO utilities specifically?**

**A11.** No. While I agree with Drs. Kryzanowski and Roberts that OPG, as a generator, is a riskier utility than any of the ATCO Utilities, the capital structure adopted by the OEB cannot be viewed as an appropriate marker for setting capital structures for the ATCO Utilities.

First, in order to be able to put weight on the OEB's finding, it is necessary to know how capital markets interpret that finding. It is perhaps obvious if a regulator determined that the appropriate equity ratio for a pure-play utility was 30% and the credit rating agencies reacted by rating the utility in the B (non-investment grade) category, the 30% would not be viewed as a reasonable benchmark for establishing equity ratios for other utilities. In OPG's case, it has been assigned a stand-alone (i.e., separate from the rating of its provincial parent) credit rating of BBB by S&P. However, a BBB credit rating is not an appropriate target for the ATCO Utilities, as discussed in more detail below.

The BBB credit rating is for the consolidated operations of OPG, half of which are not regulated. Thus, it is difficult, if not impossible, to know how the market assesses the capital structure, ROE and credit metrics for the regulated operations on a stand-alone basis. Nevertheless, on a consolidated basis, the credit metrics of OPG are considered weak for the stand-alone rating of BBB.[3] OPG's actual common equity ratio, based on reported debt and common equity at the end of 2008 was 64%.

Second, in coming to its conclusion, the OEB determined that breadth of protection afforded OPG through deferral accounts was greater for OPG than other utilities. Third, the OEB's analysis did not properly reflect the

[3] Standard & Poor's, *Ontario Power Generation, Inc*., August 18, 2008. The actual S&P rating of OPG is A- due to its close relationship with its higher rated owner, the Province of Ontario.

interdependence between capital structure and ROE. The OEB considered that the common equity ratios of merchant generators were lower than the common equity ratio requested by OPG, but they did not simultaneously consider the cost of equity to those same merchant generators. Failure to recognize the interrelationship between the capital structure and required ROE will likely result in a flawed determination of both, and thus a flawed determination of the overall cost of capital.

Finally, their analysis is circular. In the OPG proceeding, Drs. Kryzanowski and Roberts used the allowed common equity ratio of ATCO Pipelines to establish their recommended capital structure for OPG. Now, in this proceeding, they use the capital structure adopted for OPG to establish the appropriate capital structure for ATCO Pipelines.

### D. Incentive to Maximize Debt

**Q12. Drs. Kryzanowski and Roberts claim that the currently allowed capital structures are overly conservative due to the lack of incentive to maximize debt, partly due to the incentive to provide parent companies additional debt capacity (page 20, lines 21-27). Please comment on these claims.[4]**

**A12.** With respect to the implication that parent companies under-leverage their utility subsidiaries in order to provide themselves additional debt capacity, there is absolutely no evidence that CU Inc. has under-leveraged the ATCO Utilities. As noted in Note 13 of CU Inc.'s 2008 Audited Financial Statements,

[4] Dr. Booth raises the same issue when he raises the spectre of double leveraging at page 47 of his testimony on behalf of CAPP, stating that parent companies have an incentive to finance the utilities with as much equity as possible to shift the tax advantages of debt to the parent. In response to ATCO-CAPP-23, asking for any evidence of double leveraging by the Alberta utilities, Dr. Booth stated that he "has not claimed that there is any double leveraging on the part of Alberta utilities."

*The Corporation's objectives when managing capital are:*

1. *to safeguard the ability to continue as a going concern, so that it can continue to provide returns to its share owner and benefits for other stakeholders;*

2. *to maintain an appropriate credit rating in order to provide efficient and cost effective access to funds required for operations and growth; and*

3. *to remain within the capital structure approved by the AUC.*

## E. Views of Debt Rating Agencies on Levels of Deemed Equity Ratios

**Q13. Do the debt rating agencies agree with Drs. Kryzanowski's and Roberts's claim that the allowed capital structures are overly conservative?**

**A13.** No. The equity ratios approved for CU Inc.'s regulated operations by the AUC are considered by the credit rating agencies to be relatively low.

As I noted in my direct testimony (page 27), subsequent to Decision 2004-052, DBRS referred to the low deemed equity and returns as a "challenge" for the ATCO Utilities. The DBRS report[5] for ATCO Ltd. stated,

> *While ATCO's diversified operations, coupled with the Company's prudent management approach, provide a level of earnings stability, additional challenges over the medium term include the relatively low approved returns on equity (ROE) and deemed equity for the regulated businesses, continuing regulatory risk and lag and ATCO's merchant power exposure in Alberta.*

I also referenced (page 28) the S&P report[6] issued subsequent to Decision 2004-052, where S&P commented on the thin equity layers allowed the ATCO group of utilities, stating,

[5] DBRS, *Credit Rating Report, ATCO Ltd.,* December 29, 2004.

> *The regulatory regime, although comparable with other provinces in Canada, typically approves less generous returns on thinner equity layers than those approved for ATCO's global peers. Approved returns for ATCO's regulated businesses are 9.6% on equity layers varying from 33%-43% of total capital.*

More generally, my direct testimony at pages 27 to 30 supports the conclusion that the debt rating agencies find the allowed common equity ratios of the universe of Canadian utilities to be weak.

To provide some further context, the case of Terasen Gas Inc. is illustrative. Terasen Gas is rated A3 by Moody's, one notch from the Baa category. Terasen has an allowed common equity ratio of 35% and allowed ROEs that have averaged 8.5% over the past three years. Moody's quantitative methodology for rating North American natural gas distributors considers four main factors: sustainable profitability (20% weight); regulatory support (10% weight); ring-fencing (10% weight); and financial strength and flexibility (60% weight). The sustainable profitability and financial strength and flexibility factors are divided into sub-categories with individual weights assigned to the sub-categories. The financial strength and flexibility factors, each of which is given 15% weight are: EBIT Interest Coverage, Retained Cash Flow/Debt, Debt/Book Capitalization, and Free Cash Flow/Funds from Operations. On the first three of those factors, which are largely a function of the BCUC's directives on capital structure and ROE, Terasen Gas is rated Ba, below investment grade.[7]

In its May 2008 report, Moody's noted that

> *Notwithstanding TGI's relatively low risk business profile, its financial profile is considered weak at the A3, senior unsecured rating level. Accordingly, further sustained weakening of TGI's financial metrics, for instance ROE below 8%, EBIT/Interest below 2x, RCF/Debt below 5%*

[6] S&P, *Research Update: ATCO Group of Companies 'A' Ratings Affirmed, Outlook Stable,* November 9, 2004.

[7] Moody's, *Credit Opinion: Terasen Gas Inc*., May 27, 2008.

> *and/or Debt/Book Capitalization (Excluding Goodwill) above 65%, would likely lead to a downgrade of TGI's rating.*

Also of note is the fact that while regulatory risk is frequently cited as the reason the universe of Canadian utilities is rated higher than the universe of U.S. utilities, Moody's does not consider Terasen Gas to have superior regulatory support to Mr. Coyne's proxy U.S. LDC sample. Terasen Gas, which operates in one of the more supportive regulatory environments in Canada, has an Aa rating on regulatory support; the median regulatory support rating for the U.S. gas distributors in Mr. Coyne's proxy sample is also Aa.[8]

Following the NEB's TQM decision, DBRS commented that TQM has had a relatively weak financial profile largely due to its low common equity ratio and low allowed ROE and that it believed the NEB's decision strengthens TQM's financial profile and its position within its rating category (TQM is rated A (low) by DBRS).[9]

The conclusion of Drs. Kryzanowski and Roberts that the regulatory process results in allowed common equity ratios that are "overly conservative" is not borne out by the reaction of capital market participants.

### F. Allowed versus Earned ROEs and Relevance to Capital Structure

**Q14. Drs. Kryzanowski and Roberts appear to use Canadian utilities' ability to earn ROEs above the allowed ROEs as support for the proposition that the allowed equity ratios can be lowered from their existing levels. Would this be a reasonable course of action?**

**A14.** No. Effectively, what Drs. Kryzanowski and Roberts are recommending is that the utilities be penalized for operating as they should, which entails seeking to

[8] Moody's, *Rating Methodology: North American Regulated Gas Distribution Industry (Local Distribution Companies)*, October 2006.

create efficiencies which benefit both ratepayers and shareholders. Lowering the common equity ratios because utilities have exceeded the allowed return (which they should be incented to do) would be punitive. Moreover, it would potentially produce perverse outcomes in the form of disincenting the utilities to commit capital to service and reliability improvements.

Moreover, it should be pointed out that it is not reasonable to attribute the level of earnings of the parent company to overearning by the regulated subsidiaries, as is suggested by Drs. Kryzanowski and Roberts. The minimum filing requirements demonstrate that the ATCO Utilities earned on average approximately 9.6% for the five year period ending 2007 (compared to an allowed ROE of approximately 9.2%). The average ROE for CU Inc. reported over this same period was 11.4%. The material difference between the 11.4% and the 9.6% reflects performance by unregulated operations.

To suggest that the higher ROE of CU Inc. is due to overearning by the regulated utilities is patently incorrect. Further, it ignores the stand-alone principle. To suggest that the ROE of CU Inc. should be relied upon in any way to lower either the allowed capital structures or the ROEs of the utilities is tantamount to endorsing further cross subsidization of the regulated operations by the unregulated operations.

The strong performance of the unregulated operations has benefitted the ratepayers of the ATCO Utilities by allowing CU Inc. to maintain higher credit ratings and lower debt costs than it would have been able to maintain in the absence of the unregulated operations. The lower debt costs have been mirrored down to ratepayers. Ratepayers already benefit from the lower costs achieved through the diversification of CU Inc. The suggestion that the common equity ratios of the ATCO Utilities should be lower due to the earnings of the

[9] DBRS, *Trans Quebec & Maritimes Pipeline Inc., DBRS Comments on NEB Decision on TQM's Cost of Capital Application,* March 20, 2009.

unregulated operations constitutes cross-subsidization of the regulated operations by the unregulated operations and contravenes the stand-alone principle.

**Q15. How does the fact that on average the ATCO Utilities have earned an ROE modestly higher than the allowed ROE impact any assessment of their risk relative to U.S. utilities?**

**A15.** While I acknowledge that the available data to make this assessment are not perfect, as it is virtually impossible to assemble data for the individual U.S. utilities on a basis similar to what was provided by the Alberta utilities in the minimum filing requirements, the data I provided in my direct testimony on Schedules 4 and 5 provide a reasonable perspective. Schedules 4 and 5 provide the average achieved ROEs of the A rated U.S. electric and gas utilities, most of which are the operating companies. The average and median reported achieved ROEs for the electric utilities were both 11.6% and for the gas utilities were 12.1% and 11.2% respectively over the period 2005-2007 (both on average and median equity ratios of approximately 47%). For the same three year period, the average ROE allowed by U.S. state regulators for both electric and gas utilities was 10.4% on common equity ratios of approximately 48%. The difference in actual versus allowed ROEs in Canada versus the U.S. does not suggest that Canadian utilities face any lower risk than their similarly rated peers.

### G. Higher Cost of Capital to BBB Rated Utilities

**Q16. Drs. Kryzanowski and Roberts conclude that debt ratings in the BBB category are adequate for the Alberta utilities and for Canadian utilities more generally. Do they actually demonstrate that it would be less costly to ratepayers for utilities to be rated BBB than in the A category?**

**A16.** No, they do not. They provide no analysis of the difference in the cost of capital (debt and equity) between BBB rated and A rated companies to support their contention that a BBB rating is adequate.

**Q17. Is this a relevant consideration?**

**A17**. Yes. If the cost of capital is higher for utilities rated in the BBB category than for utilities rated A, there is no reason to deem capital structures which are only adequate for BBB ratings. Ratepayers will be better served if the utilities are capitalized and allowed returns which are compatible with achieving ratings in the A category.

**Q18. What is the difference between the cost of debt for utilities rated BBB and those rated A?**

**A18.** Under current market conditions, the difference in cost of debt for U.S. utilities rated BBB and those rated A is approximately 1.5 percentage points (8% versus 6.5%).

**Q19. Are current conditions indicative of the long-run historical differences in the cost of debt of A rated versus BBB rated companies?**

**A19.** No. The spreads are currently significantly wider than they have been on average historically. Historically (1947-2009), the average difference in the cost of long-term debt for A rated and BBB rated utilities has been on the order of 35 basis points.

**Q20. Given the difference between the long-term differential and the current differential, is the latter relevant?**

**A20.** Yes. The current spread represents the differential in debt costs that utilities face today and that will be incurred by ratepayers over the life of debt that is raised under current market conditions. While history suggests that spreads should narrow, the extent of the narrowing and the timing thereof are uncertain.

**Q21. Are the spreads that you cite for U.S. utilities relevant to Canadian utilities?**

**A21.** Yes. As I noted in my direct testimony at pages 19-20, the spreads for A rated utilities in the two countries have been similar; that conclusion remains valid. The yields on long-term government bonds are virtually identical in the two countries and thus the yields on A rated long-term utility debt are also virtually identical. The spreads for BBB rated utilities in the U.S. are currently approximately 425 basis points (cost of 8%). Regulated energy utilities in Canada (e.g., EPCOR Utilities) with ratings in the BBB category are also facing spreads of that magnitude in the Canadian market. Drs. Kryzanowski and Roberts suggest that Canadian utilities could be BBB rated and raise debt in the U.S. market. In that case, Canadian utilities would face the same 400+ basis point spreads in the U.S. market as BBB rated U.S. utilities are facing.

**Q22. How did you estimate the difference in the overall cost of capital between A rated utilities and BBB rated utilities with similar levels of business risk?**

**A22.** As the point of departure, I divided all the U.S. gas and electric utilities rated as investment grade by Standard & Poor's into two groups, those rated A- or better and those rated BBB- to BBB+. I then eliminated from each group all utilities with a business risk profile which was lower than "Excellent" to control for differences in business risk.[10] I was then left with two samples of (1) 15 companies rated A on average with "Excellent" business profiles and (2) 20 companies rated BBB on

[10] I recognize that the business risk assessment of the credit rating agencies is from the bondholders' perspective and may not fully reflect the assessment by equity shareholders. The circumstances of Maritimes and Northeast Pipeline, discussed by Dr. Gaske in his rebuttal testimony at page 12, are a case in point.

average also with "Excellent" business profiles. The table below summarizes various risk and cost of equity measures for the two samples.

**Table 1**

| Sample | S&P Business Profile Score | S&P Financial Risk Score | Common Equity Ratio (2004-2008) | Bloomberg "Raw" Beta | Bloomberg "Adjusted" Beta | DCF Cost of Equity |
|---|---|---|---|---|---|---|
| A rated | Excellent | Intermediate | 44% | 0.74 | 0.83 | 11.7% |
| BBB rated | Excellent | Aggressive | 40% | 0.83 | 0.89 | 13.8% |

Source: Schedule 1, pages 1 and 2 and Schedule 2, pages 1 and 2.

**Q23. What has been the difference in the capital structure between utilities rated A and utilities of similar business risk rated BBB?**

**A23.** As indicated in Table 1 above, the five-year average difference between the book value common equity ratios of the two groups has been approximately four percentage points, 44% versus 40% (See Schedules 1 and 2). The four percentage point difference is similar to the average difference recommended by Drs. Kryzanowski and Roberts for the Alberta utilities and the common equity ratios proposed by the Alberta utilities.

**Q24. What is the difference in the cost of equity of the two samples?**

**A24.** The estimated difference in the cost of equity depends on both the cost of equity test used and the assumptions made regarding the values of the inputs to the tests. The table below provides a range of differences using various assumptions.

**Table 2**

| Differential Based on: | | |
|---|---|---|
| Market Risk Premium of 5.1% and Raw Betas[11] | Market Risk Premium of 6.75% and Adjusted Betas[12] | DCF Test |
| 0.48% | 0.40% | 2.1% |

Sources: Schedule 1, pages 1 and 2 and Schedule 2, pages 1 and 2.

Table 2 above indicates that, based on the CAPM, the cost of equity for the BBB rated utilities is approximately 40-50 basis points higher than for the A rated utilities, and based on the DCF model, is as much as two percentage points higher.

**Q25. How did you use this information to test the proposition that the cost of capital for an A rated utility would be lower than the cost of capital for a BBB rated utility?**

**A25.** I started by estimating the pre-tax cost of capital for an A rated Alberta utility at a 60%/40% debt/equity structure using the current cost of debt for an A rated utility (6.5%) and a cost of equity approximately equal to that estimated by Mr. Coyne for his benchmark samples of electric and gas utilities, which are rated in the A category. The indicated pre-tax cost of capital is set out in the table below:

[11] Based on Drs. Kryzanowski's and Roberts's market risk premium of 5.1%. Differential calculated as: ("Raw" Beta $_{BBB}$* MRP) – ( "Raw" Beta $_{A}$* MRP) = .48%

[12] As per *Opinion on Capital Structure and Fair Return on Equity for Ontario Power Generation of Kathleen C. McShane* filed in response to CAL-ATCO-4. Differential calculated as: (Adjusted Beta$_{BBB}$ * MRP) – (Adjusted Beta$_{A}$ * MRP) =.40%

**Table 3**

| | Proportion | Cost Rate | Weighted Component |
|---|---|---|---|
| Debt | 60% | 6.5%[13] | 3.9% |
| Equity | 40% | 10.5% | 4.2% |
| Cost of Capital | | | 8.1% |
| Tax at 29% | | | 1.7% |
| Pre-Tax Cost of Capital | | | 9.8% |

Source: Schedule 3, Case 1

The pre-tax cost of capital can then be compared to the pre-tax cost of capital for a BBB rated utility assuming a four percentage point higher debt ratio and the minimum estimated differentials between the costs of debt and equity for an A versus BBB rated utility, that is a 35 basis point higher cost of debt; and (3) a 45 basis point higher cost of equity. The result, shown in Table 4 below, demonstrates that, even at the lowest estimated differentials between the debt and equity costs for the two samples, the pre-tax cost of capital is slightly lower for the A rated utility.

**Table 4**

| | Proportion | Cost Rate | Weighted Component |
|---|---|---|---|
| Debt | 64% | 6.85%[14] | 4.4% |
| Equity | 36% | 10.95% | 3.9% |
| Cost of Capital | | | 8.3% |
| Income Tax at 29% | | | 1.6% |
| Pre-Tax Cost of Capital | | | 9.9% |

Source: Schedule 3, Case 1

The pre-tax cost differential will be much greater in favour of the A rated utility at current A/BBB utility debt cost spreads and the estimated difference in the samples' DCF cost of equity. At the current spread between the cost of long-

[13] Equal to current cost (Long Canada of 3.65% plus 2.85% spread) or alternatively, cost over the long-term equal to forecast long-term Canada bond yield of 5.25% plus spread of 1.25%.
[14] Equal to cost of long-term A rated utility debt plus long-term average BBB/A yield spread.

term A and BBB rated debt of 1.5 percentage points and the DCF cost of equity differential of 2.1 percentage points, the pre-tax cost of capital for a BBB rated utility is 1.7 percentage points higher than for an A rated utility (See Schedule 3, Case 2).

**Q26. To what extent is the outcome dependent on your assumption regarding the "starting" cost of equity for the A rated utility?**

**A26.** The same conclusion would be drawn if the cost of equity for the A rated utility with 40% equity were equal to the AUC's 8.75% ROE for 2008 rather than 10.5% and the cost of equity for the BBB utility with 36% equity were 0.45% higher, at 9.20%, as demonstrated in Schedule 3, Case 3. The overall cost of capital is higher for BBB rated utilities.

**Q27. What other assumptions did you test to determine how robust the conclusions were?**

**A27.** Using both the 10.5% ROE and the 8.75% ROE as points of departure, I determined what the breakeven point on the ROE differential would have to be so that the pre-tax cost of capital for the A rated utility at 40% equity and the BBB rated utility at 36% equity were the same. As shown in Schedule 3, Case 4, using the 10.5% ROE as the A rated utility ROE, the cost of capital would be equal if the ROE for the BBB rated utility were only approximately 25 basis points higher than the ROE for the A rated utility. Using the 8.75% AUC formula ROE for 2008 as the point of departure, the breakeven point occurs when the ROE for the BBB rated utility is virtually identical to the A rated utility ROE (Schedule 3, Case 5).

The breakeven points in both cases are lower than the differential in ROE indicated by the application of the CAPM and materially lower than indicated by the differences in the DCF cost of equity between the two samples. Both breakeven scenarios support the proposition that the cost of capital will be lower for the A rated utility with a 40% equity ratio than if it were capitalized with a 36% common equity ratio and were only able to achieve ratings in the BBB category.

The differentials, or breakeven points, are even smaller at a lower corporate income tax rate. By 2012, the combined Alberta/Federal corporate income tax rate is expected to be 25%, compared to the 2009 statutory 29% rate which has been utilized to this point. At a 25% corporate income tax rate, and a 10.5% ROE for the A rated utility, the ROE would need to be only approximately 15 basis points higher if the utility had 36% equity and a BBB rating. Using the 8.75% 2008 AUC ROE for the A rated utility at 40% equity, breakeven occurs with no incremental cost of equity to the BBB rated utility at 36% equity (Schedule 3, Cases 6 and 7).

In summary, using a wide range of assumptions, the cost of capital is lower for A rated utilities than for BBB rated utilities. There is no cost-based reason to set capital structures at levels which would only permit the Alberta utilities to achieve BBB ratings. The conclusion that the capital structures should be established consistent with the ability to achieve and maintain A ratings is further bolstered by the greater financial flexibility afforded A rated utilities (e.g., better market access) and the relatively small size of the BBB debt market in Canada.

### H. Interest Coverage Analysis

**Q28. Drs. Kryzanowski and Roberts argue that bond ratings are generally poorer measures of credit risk than financial ratios. As evidence they point to the similar interest coverage ratios but different debt ratings for their sample of Canadian companies as evidence of the weakness of bond ratings. Does the evidence they point to support their conclusion?**

**A28.** No. Credit ratings reflect both business risks and financial risks. Companies with different levels of business risk will need to maintain different levels of financial parameters or credit metrics to achieve the same credit ratings. Emera and Canadian Utilities Limited are cases in point. Emera is rated BBB by S&P; Canadian Utilities Limited is rated A. Canadian Utilities Limited is assigned a business profile score of "Excellent" by S&P; Emera is only rated "Satisfactory", two categories more risky on S&P's business risk scale. The two companies are placed in the same "Intermediate" financial risk category, but the higher business risk of Emera indicates that it **should** have a lower credit rating. Consequently the fact that companies with similar financial risks have different bond ratings says nothing about the weakness of credit ratings.

**Q29. Drs. Kryzanowski and Roberts perform an interest coverage analysis to demonstrate that their recommended capital structures and ROEs are adequate for a BBB rating. Please discuss the concerns that you have with their analysis.**

**A29.** Drs. Kryzanowski and Roberts project what they refer to as pre-tax interest coverage ratios using their recommended capital structures, a cost of debt, and their recommended ROE of 7.9%. The resulting interest coverage ratios which they claim are adequate for a BBB rating range from 1.6X at a 30% common equity ratio (recommended for ENMAX and EPCOR Transmission) to 2X at a 42% equity ratio (recommended for ATCO Pipelines at the status quo).

The first concern I have with the analysis is the assumption that a BBB rating is appropriate. I have already established that a BBB rating does not result in a lower cost of capital than an A rating. Thus the very premise of Drs. Kryzanowski and Roberts's analysis is flawed.

Second, one of the key assumptions that Drs. Kryzanowski and Roberts employ to estimate interest coverage is flawed. Their analysis of interest coverage is based on AltaLink's 5.64% embedded cost of debt as the basis for their estimates. AltaLink's embedded debt cost of 5.64%: (1) represents the embedded cost of debt for an A rated utility, not a BBB rated utility; and (2) represents the embedded cost of debt of a utility which had the good fortune of being able to raise virtually all of its outstanding debt during some of the most robust debt markets in recent history. A 5.64% embedded debt cost is materially lower than (1) the embedded cost of debt of the ATCO Utilities by a large margin[15] and (2) significantly lower than the rates that at which a BBB rated utility could raise long-term debt in current markets. The cost of new long-term debt in current markets even for a split-rated utility like Nova Scotia Power would be close to 7.5%. By understating the relevant debt cost, Drs. Kryzanowski and Roberts overstate the interest coverage ratios that would result. Table 5 below compares the interest coverage ratios as calculated by Drs. Kryzanowski and Roberts[16] with coverage ratios using a 7.5% cost of debt for a BBB rated utility rather than the 5.64% used by Kryzanowski and Roberts.

Third, Drs. Kryzanowski and Roberts do not actually estimate pre-tax (or EBIT) interest coverage ratios; they estimate after-tax interest coverage ratios. The table below also includes the pre-tax (or EBIT) indicated coverage ratios using a 7.5% cost of debt for a BBB rated utility and a full income tax allowance at the combined 2009 federal/provincial corporate income tax rate of 29% would produce EBIT coverage ratios as follows:[17]

**Table 5**

| Equity Ratio | 30% | 33% | 34% | 35% | 40% | 42% |
|---|---|---|---|---|---|---|
| After-tax Coverage Ratios at 5.64% Debt Cost | 1.60X | 1.69X | 1.72X | 1.75X | 1.93X | 2.01X |
| After-Tax Coverage Ratios at 7.5% Debt | 1.45X | 1.52X | 1.54X | 1.57X | 1.70X | 1.76X |

[15] ATCO Electric's embedded cost of debt for 2008 was 6.6%, for example.
[16] The EBIT coverage ratios at 33% and 34% equity, Drs. Kryzanowski and Roberts's recommended ratios for ATCO Electric Transmission and ATCO Gas were also calculated as reference points.
[17] At the combined provincial/federal income tax rate of 25% anticipated by 2012, the indicated EBIT coverage ratios would be lower than those shown at the 2009 29% rate.

| | | | | | | |
|---|---|---|---|---|---|---|
| Cost | | | | | | |
| EBIT Coverage Ratios at 7.5% Debt Cost | 1.64X | 1.73X | 1.76X | 1.80X | 2.00X | 2.10X |

The corrected and revised (for debt cost) ratios are not materially different than Drs. Kryzanowski and Roberts's initial calculations. Even at the highest equity ratio recommended by Drs. Kryzanowski and Roberts, the indicated EBIT coverage ratio barely reaches 2.0X. By comparison, in Decision 2004-052, the EUB stipulated that a pre-tax interest coverage ratio near two times was indicated for the **lowest** business risk utilities. The EUB also expected that pre-tax interest coverage ratios would improve over time as the embedded debt cost declined.

Effectively what Drs. Kryzanowski and Roberts assert is that the utility facing the highest business risk (i.e., ATCO Pipelines) could achieve a debt rating of investment grade debt ratings with an interest coverage ratio barely exceeding 2X. Notwithstanding Drs. Kryzanowski and Roberts's faulty premise, i.e. the adequacy of a BBB rating, pre-tax interest coverage ratios in the 1.6X to 2.1X range are well below the ratings guideline levels for investment grade ratings and the actual average coverage levels achieved by investment grade utilities globally (See Table 6 below).

**Q30. What are the pre-tax EBIT coverage guidelines of the debt rating agencies?**

**A30.** Moody's includes EBIT coverage as one of its quantitative guidelines in its ratings methodology for North American natural gas distributors.[18] Its guideline ranges are 3-5 times for an A rating and 2-3 times for a Baa rating.[19] The indicated coverage ratio for ATCO Gas at Drs. Kryzanowski and Roberts's proposed ROE and common equity ratio of 34% is less than 1.8X, or in the non-

[18] Moody's does not include EBIT coverage as one of its key quantitative guidelines for electric utilities.

investment grade category. Terasen Gas, the only Canadian gas distributor which is rated using Moody's North American gas distribution rating methodology, is assigned a rating of Ba (non-investment grade) on the EBIT coverage metric. Its EBIT interest coverage ratios averaged 2X from 2004-March 2008.[20] The gas distributors in Mr. Coyne's sample of comparable gas distributors had an EBIT interest coverage rating of A.[21]

Moody's guideline ranges for North American natural gas pipelines are 4 to 5 times for an A rating on the EBIT coverage metric and 3 to 4 times for a BBB rating. NGTL, which has been rated using Moody's gas pipeline methodology, was assigned a non-investment grade rating of Ba on EBIT interest coverage (coverage in the 2 to 3 times range). Coverage in the 1-2 times range (as per Drs. Kryzanowski and Roberts's recommendations) would produce only a B rating on this metric. Moody's defines a B credit rating as "Speculative and subject to high credit risk".

While S&P no longer utilizes EBIT coverage as one of its three principal quantitative guidelines, it reports EBIT coverage as one of the seven major quantitative financial metrics for the global utilities it rates.[22] The average EBIT coverage ratios reported for A rated and BBB rated utilities over past five years were as follows:

**Table 6**

| Three Year Average Ending: | A rated (times) | BBB Rated (times) |
|---|---|---|
| 2007 | 3.4 | 3.1 |
| 2006 | 3.4 | 2.9 |

[19] Moody's, *Rating Methodology: North American Regulated Gas Distribution Industry (Local Distribution Companies)*, October 2006.
[20] Moody's, *Credit Opinion: Terasen Gas Inc*., May 27, 2008.
[21] Moody's, *Rating Methodology: North American Natural Gas Pipelines*, December 2006.
[22] The former EBIT interest coverage guidelines for the lowest business risk profile score assigned to a Canadian utility and an A rating ("2" on a scale of "1" to 10) was 2.3X to 2.9X. Most Canadian utilities were in the "3" category, for which the range for an A rating was 2.8 to 3.4 times. S&P, *Utilities and Perspectives*, June 21, 1999.

| | | |
|---|---|---|
| 2005 | 3.7 | 3.2 |
| 2004 | 3.6 | 3.0 |
| 2003 | 3.2 | 2.7 |

Sources: S&P, *Credit Stats Utility Comparative Ratio Analyses, Long Term Debt,* various issues.

The actual EBIT coverage ratios maintained by companies rated BBB by S&P are materially higher than the range of 1.6X to 2.1X indicated by Drs. Kryzanowski and Roberts's recommendations and demonstrate the inadequacy of those recommendations even for BBB ratings.

## I. Business Risk

**Q31. As regards the testimony of Drs. Kryzanowski and Roberts with respect to business risk and their resulting capital structure recommendations, do you have any comments?**

**A31.** As a general comment, it is inconsistent that Drs. Kryzanowski and Roberts cite the debt rating agencies' views on business risk throughout their evidence as support for own analysis, and yet simultaneously appear to reject their quantitative guidelines and, more broadly, call into question the reliability of the ratings that the agencies assign.

**Q32. Drs. Kryzanowski and Roberts recommend a common equity ratio of 33% for ATCO Electric Transmission. Is this recommendation consistent with their conclusion that the business risk of electric transmission has increased?**

**A32.** No, not in relationship to the EUB's finding in Decision 2004-052. In that decision, the Board concluded that a 33% equity ratio was appropriate for electric transmission. Drs. Kryzanowski and Roberts are recommending a three percentage point increase in the equity ratio for ATCO Electric Transmission compared to their recommendation in the last generic proceeding. Using the

2004-052 finding as a point of departure, a three percentage point increase in the common equity ratio for ATCO Electric Transmission would result in a common equity ratio of 36%.

**Q33. How does the proposed equity ratio of 33% (in combination with the proposed ROE of 7.9%) compare to the allowed capital structures and ROEs of U.S. electric transmission utilities?**

**A33.** The resulting overall return is well below the returns available to those investing in transmission utilities in the U.S. The common equity ratios adopted for U.S. electric transmission utilities by the FERC have been approximately 50% in conjunction with ROEs (before incentives) averaging over 11% (and over 12% with incentives) since the beginning of 2007.

**Q.34. Are the U.S. electric transmission utilities comparable to ATCO Electric Transmission?**

**A34.** Yes. As I noted in my direct evidence (page 36), S&P, in a comparative study of AltaLink and two stand-alone U.S. transmission companies (American Transmission Co. (ATC) and Independent Transmission Co.), concluded that AltaLink faced higher business risk than ATC. This conclusion was largely due to S&P's conclusion that ATC faced the lowest regulatory risk of the three transmission companies. S&P referred to ATC's FERC-approved settlement that includes a 12.2% ROE based on a hypothetical capital structure of 50% equity, the ability to earn a return on CWIP, the fixed monthly fee charged, which reduces exposure to cash flow variability, rate setting based on prospective data, and an annual end-of-year true up. S&P noted that the CWIP treatment is an important feature that reduces upfront financing risk and liquidity concerns, given the company's large planned capital expenditure program.[23] AltaLink is of similar business risk to ATCO Electric Transmission.

**Q35. How would the adoption of Drs. Kryzanowski and Roberts's recommendations affect the incentive to allocate capital to electric transmission investment in Alberta?**

**A35.** The existing allowed returns and common equity ratios are already viewed as a disincentive to allocate capital to electric transmission (as well as to utility investments in other sectors). In its May 2004 Briefing entitled *Electricity Restructuring: Opening Power Markets*, the Conference Board stated,

> *Investors are discouraged by limitations on the regulated cost recovery for transmission upgrading. Transmission companies are simply not seeing favourable risk/return ratios on their investments, and know that they can realize better returns in the United States, where regulated rates of return are much higher. Rates of return to Canadian firms for transmission projects are around 9 to 10 per cent, well below the 13 to 14 per cent available to U.S. companies. These lower rates discourage investment in Canadian utilities. Moreover, investors are additionally deterred by the fact that existing cost-of-service rates do not reflect the economic value of the transmission grid.*

While the ROEs in both countries are now lower than when this statement was made, the gap to which the Conference Board referred persists. The adoption of Drs. Kryzanowski and Roberts's recommendations would magnify the disincentive which already exists.

**Q36. How do Drs. Kryzanowski and Roberts's proposals comport with Provincial energy policy that seeks to promote investment in the electricity transmission grid?**

[23] S&P, *Peer Comparison: North American Stand-Alone Transmission Companies Deliver Electricity and Profits",* April 2006.

**A36.** The proposals are inconsistent with Provincial energy policy as the overall returns for electricity transmission, including the common equity ratio, recommended by Drs. Kryzanowski and Roberts would discourage investment in the electricity transmission grid. Moreover, their adoption would create an untenable tension among the inability of the Transmission Facility Owners to refuse direct assigned projects from the AESO, their need to obtain the required financing, the desire of the Provincial government to create a positive investment climate and a fair return to shareholders.

**Q37. Drs. Kryzanowski and Roberts recommend an equity ratio for ATCO Gas of 34%, less than for electricity distribution and reduction of three percentage points from their recommended 37% in the last generic proceeding. Are the relative risk positioning of ATCO Gas and the reduction in the common equity ratio of ATCO Gas reasonable?**

**A37.** No. First, the position of Drs. Kryzanowski and Roberts that ATCO Gas' equity ratio should be changed due to the weather deferral account is inconsistent with (1) their sole reliance on the Capital Asset Pricing Model (CAPM) for the purpose of determining the ROE and (2) the position of Mr. Marcus (on whom Drs. Kryzanowski and Roberts draw for business risk analysis; see response to ATCO-UCA-2) regarding the relevance of weather as an operating risk in the determination of the cost of capital. The CAPM holds that investors should only be compensated for non-diversifiable risks. Weather is a diversifiable risk. If no compensation is required for weather risk when a gas utility is fully exposed to that risk, logically no compensation should be taken away when weather risk is mitigated. Mr. Marcus's evidence explicitly references the ability to diversify weather risk in coming to the conclusion that no compensation in the ROE or capital structure is warranted for weather risk as it applies to operating or cost risk (page 14). Similar logic would suggest that no reduction in compensation to shareholders is warranted on the revenue side if exposure to weather variability is mitigated.

**Q38. Is there any evidence that Drs. Kryzanowski and Roberts specifically considered weather risk when they made their recommendation for the common equity ratio for ATCO Gas in the last generic proceeding?**

**A38.** No. They considered the equity ratios generally of other natural gas distributors in Canada, some with weather protection and some without. They did not consider specifically whether ATCO Gas' equity ratio should be higher or lower than the average for the industry based on its exposure to weather. Again, it makes no sense to take away compensation for weather when the equity ratio they recommended in the last proceeding reflected no more than the typical ratio for the Canadian gas distribution industry, with no differentiation based on weather protection.

**Q39. Have the equity ratios of the gas utilities which Drs. Kryzanowski and Roberts relied upon as benchmarks in determining the appropriate equity ratio for ATCO Gas in the last generic proceeding changed?**

**A39.** Yes. Of the five non-Alberta gas distribution utilities which the witnesses used as benchmarks to determine the appropriate capital structure for ATCO Gas, four of them have had their equity ratio increased since the last generic proceeding. In reducing their recommended equity ratio for ATCO Gas by three percentage points, Drs. Kryzanowski and Roberts have apparently ignored the upward trend in gas distribution utilities' allowed common equity ratios.

**Q40. Is a downward adjustment of three percentage points to their last recommended common equity ratio consistent with findings in this regard by other Canadian regulators subsequent to the last generic proceeding?**

**A40**. No. The ROE of Terasen Gas was reduced by 10 basis points when the BCUC initially approved its Revenue Stabilization Adjustment Mechanism (RSAM).[24] The RSAM is a more comprehensive mechanism than the weather deferral account which was recently approved for ATCO Gas. When the BCUC set the capital structure and ROE for Terasen Gas in 2006, it adopted the identical capital structure and ROE that had been adopted for Enbridge Gas, which had no weather protection. Thus, it can be inferred from that decision that the BCUC did not attribute material risk reduction to the existence of Terasen's RSAM.

**Q41. Please explain how the RSAM is more comprehensive than ATCO Gas' weather deferral account.**

**A41.** The RSAM protects the revenue of the utility against not only weather, but reductions in consumption by weather-sensitive customer classes for any reason, be it weather or greater efficiency of appliances or smaller housing units.

**Q42. Did the EUB provide significant compensation for weather risk in the last generic cost of capital proceeding?**

**A42**. No. The difference between the common equity ratios of ATCO Gas and the electricity distributors was only one percentage point, from which one can infer that the EUB concluded that weather risk could only have merited as much as one percentage point in risk compensation. One can also infer from the minor compensation that the EUB afforded ATCO Gas for weather risk that the Board assumed that the variations from normal weather would even out over time. To take away three percentage points in equity ratio as a result of the weather deferral account when little compensation was attributed to weather in the first instance is patently unreasonable.

[24] British Columbia Utilities Commission, *BC Gas Utility Ltd., 1994/1995 Revenue Requirements Application, Phase 1 Decision*, June 16, 1994.

**Q43. Does ATCO Gas' weather deferral account fully protect its revenues from weather-related variations?**

**A43.** No. ATCO Gas is still subject to some weather-related revenue variability arising from variations in demand from forecast.

**Q44. ATCO Gas' weather deferral account does not protect its revenues against reduction in customer consumption. Is the risk related to reduction in customer consumption considered to be a concern by the debt rating agencies?**

**A44.** Yes. Moody's, for example, has pointed to the decline in gross margins as a result of declining use per customer as an issue. Moody's observed that in the face of volatile natural gas prices, volatile weather patterns and other exogenous forces that would prompt gas customers to curtail gas consumption volumes from their utilities, LDC earnings and credit metrics will come under pressure. Moody's considers that gas distributors with full revenue decoupling will be better able to protect their gross margins and credit metrics.[25,26]

**Q45. Does the growth in customers not offset ATCO Gas' loss of margin due to the decline in customer consumption?**

**A45.** No. Customer growth requires additional investment to serve those customers. The revenue which is received from the new customers is required to recover the costs incurred to serve the new customers, not to offset the decline in customer usage.

[25] Moody's, *Local Gas Distribution Companies: Update on Revenue Decoupling and Implications for Credit Ratings*, June 2006.
[26] At page 4 of his direct evidence on behalf of the City of Calgary, Dr. Booth indicates that he does not view the decline in customer usage as a material issue. Clearly Moody's disagrees with this position. Further, the five-year incentive regulation plans approved for both Enbridge Gas and Union Gas in 2008 included a provision for adjustment of rates during the term of the plans to account for declines in per customer consumption. The approval of those provisions is a strong indication that declining customer consumption is a material issue.

**Q46. How does the termination of the natural gas rebate program announced in March 2009 impact ATCO Gas' risk?**

**A46.** High and volatile gas prices have been responsible for some of the observed reduction in customer usage. The termination of the natural gas rebate program removes the cap on the commodity component of customer bills and increasing ATCO Gas' exposure to the impacts of high and volatile gas prices as they relate to trends in per customer usage.

**Q47. How many of the six natural gas distributors in Mr. Coyne's sample of gas distribution utilities have revenue decoupling tariffs or similar revenue protection mechanisms?**

**A47.** All of the six LDCs have either revenue decoupling tariffs or full fixed variable rate design, i.e., one which recovers 100% of fixed costs in fixed charges. These mechanisms provide greater revenue protection than is available to ATCO Gas, indicating that ATCO Gas faces higher risk in this regard than Mr. Coyne's sample of comparable LDCs.[27]

**Q48. In that regard, how does Moody's rate Terasen Gas' regulatory support relative to that of the gas distribution utilities in Mr. Coyne's gas distribution sample?**

**A48.** As noted earlier, Moody's views the utilities in Mr. Coyne's sample of proxy U.S. gas distribution utilities as having a similar level of regulatory support on average as Terasen Gas. Since ATCO Gas does not have protection on customer consumption (nor, more generally, as comprehensive a slate of deferral accounts as Terasen Gas), were it to be rated by Moody's, ATCO Gas' regulatory support

[27] With respect to regulatory protection in total, Mr. Coyne's direct evidence (pages 54-58) and response to UCA-ATCO-45 confirm that the proxy sample of LDCs used to establish the benchmark return has no discernibly greater or lesser regulatory protection in the form of deferral accounts and recovery mechanisms than ATCO Gas.

rating would likely be somewhat lower than that of Terasen. Even with its relatively high regulatory support rating, Terasen Gas is rated A3, i.e., at the lower end of the A category, with the potential for being downgraded into the Baa category if its financial ratios deteriorate below their recent levels.[28]

**Q49. Drs. Kryzanowski and Roberts ultimately determine qualitatively that ATCO Gas faces lower business risk than the electricity distribution utilities. Is that conclusion borne out by the quantitative evidence?**

**A49.** No. Mr. Coyne's cost of equity estimates for his proxy samples of electricity and gas distribution utilities indicate that electricity distributors face a lower cost of capital than the gas distributors, all of whom, as previously noted, have more comprehensive revenue protection than ATCO Gas. The quantitative evidence supports a higher cost of capital for ATCO Gas than ATCO Electric Distribution.

**Q50. With respect to ATCO Pipelines, Drs. Kryzanowski and Roberts recommend a common equity ratio of 42% with ATCO Pipelines at the status quo. On the basis of their relative risk analysis and the capital structures used for toll setting purposes by the pipelines that the witnesses use as benchmarks, is the 42% they recommend reasonable?**

**A50.** No. As Drs. Kryzanowski and Roberts confirmed in response to UCA-ATCO-3, in arriving at their recommended capital structure of ATCO Pipelines, they use TransCanada Pipelines as the benchmark pipeline. Their evidence does not dispute the NEB's conclusions regarding the increase in TransCanada's supply and competitive risk. They compare TransCanada and NGTL and conclude that NGTL is somewhat riskier than TransCanada, recommending that NGTL's equity

[28] In its May 2008 *Credit Opinion*, Moody's stated: "Notwithstanding TGI's relatively low risk business profile, its financial profile is considered weak at the A3, senior unsecured rating level. Accordingly, further sustained weakening of TGI's financial metrics, for instance ROE below 8%, EBIT/Interest below 2x, RCF/Debt below 5% and/or Debt/Book Capitalization (Excluding Goodwill) above 65%, would likely lead to a downgrade of TGI's rating."

ratio be set two percentage points higher than TransCanada's. Finally, they recommend that the common equity ratio for ATCO Pipelines at the status quo be set eight percentage points higher than the equity ratio for NGTL.

Drs. Kryzanowski and Roberts confirmed in response to UCA-ATCO-39 that TransCanada Pipelines uses an equity ratio of 40% for tolls as per its negotiated settlement approved by the NEB in Order TG-06-2008 (May 2007). Using the most recent approved equity ratio for TransCanada of 40% as the point of departure, the resulting equity ratios for NGTL and ATCO Pipelines at the status quo should be 42% and 50% respectively, in contrast to the common equity ratios of 34% and 42% recommended by Drs. Kryzanowski and Roberts.

**Q51. Is ATCO Pipelines proposing an equity ratio of 50%?**

**A51.** No. ATCO Pipelines is proposing to maintain the most recently approved equity ratio of 43%. As shown on Table 10 of my direct testimony, the higher financial risk at the proposed equity ratio of 43% requires an ROE approximately 1.0-1.2 percentage points higher than is required at an equity ratio of 50%.

**Q52. Mr. Marcus, who provides business risk analysis on which Drs. Kryzanowski and Roberts rely, suggests that risks can be mitigated through the utilities' contribution policy, that is, utilities can require a greater percentage of costs to be collected through contributions. Do either Mr. Marcus or Drs. Kryzanowski and Roberts recognize the risks and liabilities to which any of the ATCO Utilities are exposed with respect to assets they own which are financed by contributions?**

**A52.** No. Neither Mr. Marcus nor Drs. Kryzanowski and Roberts acknowledge that the ATCO Utilities face risks and liabilities for assets financed by contributions and for which the ATCO Utilities are not compensated. Mr. Marcus' recommendation to increase the percentage of costs collected through contributions would simply increase the business risks of the ATCO Utilities for which they receive no compensation.

**Q53. Are the ATCO Utilities' contributions as a percentage of rate base relatively high compared to other utilities in Canada?**

**A53.** For ATCO Electric in total (and ATCO Electric Distribution separately) and ATCO Gas, yes. In ATCO Electric's case, contributions account for approximately 18% of both 2009 and 2010 gross rate base; in the case of ATCO Gas, they account for 18% of 2009 rate base. ATCO Gas' 18% of contributions as a percent of rate base is materially higher than the proportion of contributions of the other major gas utilities. The contributions as a percent of rate base of Terasen Gas, Gaz Metro, Enbridge Gas and Union Gas average less than 5%.

**Q54. Has the Commission ever recognized that a high level of contributions constitutes an element of business risk?**

**A54.** Yes. Decision 2002-027 (pages 12-13) for AltaGas stated, "In addition, AUI has a higher operating leverage arising from contributions. The Board considers that the fact that contributions reduce the gross equity to a value near 27% does result in an element of business risk. The risk stems from the requirement of AUI to be responsible for maintaining the assets, regardless of how they are financed."

**Q55. What would be the equity ratios of the ATCO Utilities inclusive of contributions at Drs. Kryzanowski and Roberts's recommended common equity ratios?**

**A55.** The following table shows Drs. Kryzanowski and Roberts's recommended common equity ratios and the corresponding common equity ratio with contributions included in the capital structure compared to the ATCO Utilities' proposed equity ratios with and without contributions in the capital structure.

**Table 7**

| | ATCO Electric Transmission | ATCO Electric Distribution | ATCO Gas | ATCO Pipelines |
|---|---|---|---|---|
| **Drs. Kryzanowski and Roberts** | | | | |
| Recommended Equity Ratio | 33% | 35% | 34% | 42% |
| Equity Ratio Including Contributions in Capital Structure | 30% | 26% | 28% | 39% |
| **ATCO Utilities** | | | | |
| Proposed Equity Ratio | 38% | 40% | 40% | 43% |
| Proposed Equity Ratio Including Contributions in Capital Structure | 35% | 30% | 33% | 40% |

Note: Equity Ratio Including Contributions in Capital Structure = Recommended or Proposed Equity Ratio X (100% minus Percentage CIAC of Gross Rate Base)

Sources: ATCO Utilities GRA filings.

**Q56. Please explain what this table demonstrates.**

**A56.** Table 7 demonstrates that, if the recommendations of Drs. Kryzanowski and Roberts are accepted, the proportion of the gross rate base that would actually be underpinned by common equity is equal to or less than 30% for all the ATCO Utilities except for ATCO Pipelines. Given the relatively high levels of contributions of the ATCO Utilities, the low levels of equity ratios proposed by Drs. Kryzanowski and Roberts would only exacerbate the problem associated with uncompensated business risk. Moreover, the effective equity ratios of the ATCO Utilities would be materially lower than those of other Canadian utilities whose contributions as a percent of rate base are considerably smaller.

**Q57. Hasn't ATCO Electric requested a management fee as compensation for those risks?**

**A57.** Yes, it has and the requested capital structure and ROE reflect that request. Similarly, the capital structures and ROEs recommended for ATCO Gas and ATCO Pipelines assume that a management fee will be granted to those companies.[29] The AUC needs to be cognizant of the impact of the contributions on business risk and on the lower effective common equity ratio in its assessment of the appropriate capital structure and ROE for the Company. If the management fees were to be denied, the level of business risk faced by the ATCO Utilities would warrant a higher common equity ratio and/or higher ROE than have been recommended.

## III. RESPONSE TO CAPP, DR. BOOTH AND DR. SAFIR

### A. Capital Structure Recommendations of Dr. Booth

**Q58. Dr. Booth makes recommendations for the equity ratios for ATCO Pipelines and ATCO Gas in his evidence on behalf of CAPP and the City of Calgary respectively. Do you believe his evidence on the appropriate capital structures for the two ATCO Utilities[30] is complete?**

**A58.** No. Capital structure cannot be determined based on business risk alone. Business risk analysis is qualitative in nature; there is no direct mapping from an assessment of relative business risk to a specific capital structure. Capital structure determination requires an evaluation of quantitative financial metrics, including changes in factors such as tax rates which impact on financial metrics, financing requirements, the implications of a particular capital structure (in conjunction with ROE) on debt ratings, and the comparability of the resulting overall return (combination of capital structure and ROE) to the returns of similar risk companies with which the utilities compete for capital. By not taking account

[29] Neither ATCO Gas nor ATCO Pipelines has yet requested a management fee.

[30] Dr. Booth undertakes no analysis of the appropriate capital structures for either ATCO Electric Transmission or ATCO Electric Distribution.

of these critical dimensions of capital structure determination, Dr. Booth's recommendations are of limited value.

### B. Impact of Deferral Accounts on Risk

**Q59. In Appendix G of his evidence on behalf of CAPP, Dr. Booth indicates that he sees little value in introducing U.S. utilities as comparables, in part due to the greater use of deferral accounts by Canadian utilities.[31] Does the existence of deferral accounts provide assurance to investors that amounts accrued in those accounts will be recovered?**

**A59**. No. The following Alberta example is strong evidence that investors do not view the creation of deferral accounts as assurance that deferred costs will be recovered.

In 2000, the EUB established regulations for the deferral of amounts related to price and volume variances from the forecast costs of power incurred by the Alberta distribution utilities.

Securitization was identified as an option to finance the unrecovered deferred costs, which for ATCO Electric totaled $81 million with a remaining recovery period of one year and for FortisAlberta (then Aquila Networks Canada) totaled $255 million with a remaining recovery period of one and one-half years. Securitization was supported by the EUB, which stated in Decision 2001-92, "the Board is prepared to support the securitization approach with all reasonable orders and directions to provide the necessary certainty to the financial community."

[31] The rebuttal evidence of Mr. Coyne addresses the specific issue of whether Canadian utilities have better protection due to deferral accounting than U.S. utilities. As noted above, all six of the LDCs in Mr. Coyne's proxy sample have either full revenue decoupling or full fixed variable rate design, which provide greater revenue protection than ATCO Gas' weather normalization deferral account.

In order to enter into the securitization agreement with the utilities, the Royal Bank of Canada required formal assurances from the regulator that:

(1) The holder of the deferral account is entitled to rate riders from all of the electricity users in order to recover the full amount of the deferral account with interest;

(2) The deferral accounts and the right to future rate rider payments is a transferable asset;

(3) The rate rider is non-bypassable;

(4) Each utility and its successors are obligated to bill and collect the charges on behalf of the Royal Bank; and

(5) There is a "true-up" mechanism in place for the EUB to periodically adjust the level of the rate rider to ensure full payout of the deferral accounts (plus actual funding costs incurred) within a maximum three-year term.

In addition to these regulatory assurances, the Royal Bank required the Balancing Pool of Alberta to enter into an indemnification (i.e., guarantee) agreement to cover the full amount of the purchased deferral account balances in order to protect itself from the risk that the Province of Alberta or the regulator could subsequently pass a ruling that would impair the value of the deferral accounts. Since the AA rating of the Balancing Pool was lower than the rating of the notes that the Royal Bank would be issuing to fund the deferral account balances, the Balancing Pool's political risk indemnity had to be partially backed by letters of credit.[32]

[32] EUB, *2000 Pool Price Deferral Accounts, Part T Securitization Financing*, Decision 2002-057, June 24, 2002.

The extent of the requirements of the Royal Bank in order to enter into the agreement to securitize the deferred power costs, which had no more than one and half-years to full recovery, as per the decisions which had already been issued by the regulator, highlights the fact that the use of deferral accounts does not cover off the risk of non-recovery of prudently incurred costs.

**Q60. Are there any other examples of risks associated with deferral accounts of which you are aware?**

**A60.** Yes. Since 1988, ATCO Gas operated with a deferred gas account (DGA), whose purpose was to ensure that only the costs of acquired gas were paid for by ratepayers and the utility was not at risk for those costs. In 2005, ATCO Gas filed an application with the EUB to recover gas costs associated with reconciliation of historical transportation imbalances. The EUB disallowed recovery of approximately 15% of the applied-for amounts. The City of Calgary filed for leave to appeal the EUB's decision to approve prior period adjustments on jurisdictional grounds. The Alberta Court of Appeal referred the jurisdictional question back to the EUB. The EUB confirmed its decision in 2008, whereupon the City of Calgary filed for leave to appeal the EUB's 2008 decision. In April 2009, the leave to appeal was granted by the Alberta Court of Appeal. A successful appeal by the City of Calgary could result in a total disallowance of costs to ATCO Gas of approximately $10 million, which, if it occurred in 2009, would result in a reduction in the ROE of approximately 1.25%. It is somewhat ironic that Dr. Booth considers the existence of deferral accounts to cover off risks to the utilities, when his own client is actively seeking to have costs accrued in a deferral account disallowed.

## C. Dr. Booth's recommended Capital Structure for ATCO Gas

**Q61. Dr. Booth recommends a common equity ratio of 35% for ATCO Gas in his testimony on behalf of the City of Calgary. How does his recommendation**

**compare to his recommendation for ATCO Gas in the last generic cost of capital proceeding in Alberta?**

**A61.** It is identical. In the last proceeding, Dr. Booth also recommended a common equity ratio for ATCO Gas of 35%. In other words, the approval of a weather deferral account for ATCO Gas has not caused his recommendation to change.

**Q62. What equity ratio did he recommend for Enbridge Gas in EB-2006-0034 2006?**

**A62.** He recommended 35% and stated that the weather risk to which Enbridge Gas is exposed is completely diversifiable and should not have any impact on the utility's required rate of return.[33]

**Q63. How does Dr. Booth rank ATCO Gas in business risk relative to Terasen Gas, with its RSAM, and Enbridge Gas and Union Gas, with no weather protection?**

**A63.** As he states at page 8 of his evidence, he considers ATCO Gas to be of equivalent risk to the three gas distributors.

**Q64. Given those conclusions, what would be the logical decision of the AUC regarding the capital structure for ATCO Gas?**

**A64.** The logical conclusion is that, in the absence of changes in other factors which bear on the appropriate capital structure, there would be no reason for the AUC to depart from the 38% common equity ratio that it previously adopted in Decision 2004-052.

[33] *Business Risk and Capital Structure for Enbridge Gas Distribution Inc. (EGDI*), Evidence of Dr. Laurence D. Booth before the Ontario Energy Board, November 2006, page 21.

**Q65. Have there been any such changes which should lead the AUC to approve ATCO Gas' applied-for 40% common equity ratio?**

**A65.** Yes. The factors which support increases in the common equity ratios of the ATCO Utilities, including ATCO Gas, were summarized on pages 2-3 of my direct evidence. They include the:

- Increases in allowed common equity ratios for other Canadian utilities since the Generic Cost of Capital decision;
- Stronger capital structures and credit metrics of comparable U.S. utilities with whom the Alberta utilities compete for capital;
- Factors which negatively impact credit metrics:
  - Lower income tax rates;
  - Switch from future to flow-through income taxes;
  - Higher Capital Cost Allowance (CCA) rates; and
  - High forecast level of capital expenditures.
- Concerns of capital market participants with respect to the levels of common equity ratios and ROEs for Canadian utilities.

### D. Dr. Booth's Recommended Capital Structure for ATCO Pipelines

**Q66. Dr. Booth recommends a 33% common equity ratio for ATCO Pipelines once it is integrated into the NGTL system and until that time a 37% common equity ratio because he "can no longer justify a higher common equity ratio for ATCO Pipe "North", since the competitive risk premium has now largely vanished." Please discuss the reasonableness of Dr. Booth's recommendations**.

**A66.** Dr. Booth's recommendations raise two issues. The first is whether the full implementation of the Memorandum of Agreement is sufficiently assured and the risk implications thereof are sufficiently clear so that an assessment of ATCO Pipelines' risk and cost of capital should or can be made.[34] The second issue is the business risk profile of ATCO Pipelines under the status quo including whether ATCO Pipelines' competitive risk is solely related to NGTL. I will address each of these issues in turn.

**Q67. Is the integration of the ATCO Pipelines and NGTL systems sufficiently assured so that an assessment of the business risk and cost of capital for ATCO Pipelines post-integration should or can be made?**

**A67.** No. As noted in my direct testimony (page 45), "As there are significant steps which must be taken in order for the agreement to be finalized, there remains considerable uncertainty whether the agreement will be implemented, and if it is, the timing thereof. As a result, the business risk profile of ATCO Pipelines has been assessed assuming the status quo." Questions remaining unanswered and therefore not before the Commission include the structure of the approved agreement, the resulting changes to the ATCO Pipelines system as assets are sold and acquired, changes to operating processes and the allocation of potential growth between ATCO Pipelines and NGTL.

**Q68. Have the significant steps been identified?**

**A68.** Yes. In response to CAPP-ATCO-3, the steps which had to be completed for the integration agreement to be finalized were detailed. The regulatory approvals required include not just Commission approvals for ATCO Pipelines, and now NEB approvals for NGTL, but also the approvals of the Canadian Competition Bureau. In addition, there is uncertainty, assuming it is finalized, as to the final form of the integration proposal, as any regulator (including the Canadian

[34] Drs. Kryzanowski and Roberts also recommend a common equity ratio (34%) for ATCO Pipelines post-MOA. This section thus also addresses their recommendations in this regard.

Competition Bureau) may require changes to the structure and thus to the impacts of the integration proposal.

In this context, I understand through ATCO Pipelines that the AUC has not cancelled the now suspended Competitive Pipeline Review Proceeding as there is still uncertainty with respect to the completion and approval of the Integration proposal.

Until such time as the integration agreement is finalized and the integration proposal has been fully implemented for a period of time sufficient to allow the market and competitive environment to adjust to the changes, it is premature to determine what an appropriate cost of capital might be for ATCO Pipelines.

**Q69. Please comment on the second issue, that is, Dr. Booth's contention that, even in the absence of the implementation of the integration proposal, the common equity ratio should be reduced because, as Dr. Booth alleges at page 55:**

> ***competitive risk has undoubtedly decreased for both NGTL and ATCO Pipelines. In 2003 there was considerable uncertainty surrounding the state of intra-Alberta pipeline competition.***

**A69.** Dr. Booth's conclusion is simply wrong.

First of all, CAPP incorrectly concludes in its own evidence at page 14, "If anything, the competition there was reducing and now has been replaced by the Collaboration Agreement. ATCO Pipelines and NGTL are no longer competitors they intend to be collaborators."

ATCO Pipelines and NGTL are not yet collaborators. They are taking steps towards the **potential** outcome of being collaborators.

Second, ATCO Pipelines is now facing competition from Alliance Pipeline. Although CAPP claims that Alliance is not a new factor (page 13 of CAPP evidence), the business model of Alliance has been recently evolving from an export pipeline only to a pipeline which serves intra-Alberta markets. The change from operating as a bullet line into the U.S. to a pipeline that also delivers within Alberta using a short haul service in order to allow it to "improve BC take-away", and to "serve Canadian markets"[35] is a significant development since 2003 and one which increases ATCO Pipelines' competitive risk.

Aux Sable has announced its intention to build an extraction plant on the Alliance Pipeline at Fort Saskatchewan which would produce lean off stream gas. That gas production would likely be marketed gas to industrial customers currently served by ATCO Pipelines in the Fort Saskatchewan area. An incremental supply source in the Fort Saskatchewan area of this type would add a significant dimension of competitive risk that was not envisioned in 2003.

**Q70. In 2002, didn't the EUB deny NGTL's initial attempt to serve industrial customers in the Ft. Saskatchewan area with a facilities application?**

**A70.** Yes, it did. However, the application itself (1) made clear that NGTL was interested in serving a key ATCO Pipelines' market; and (2) underscored the critical nature of this market to the health of the ATCO Pipelines system. The approval of the proposed NGTL Ft. Saskatchewan facilities extension would have had a significant negative impact on the ATCO Pipelines system. Industrial markets would have moved to NGTL for service, thus eliminating an important market for ATCO Pipelines receipt customers. Many of the receipt customers would then have moved from the ATCO Pipelines system to NGTL to avoid dual tolling. The loss of both industrial and producer (receipt) customers would have required significant rate increases for ATCO Pipelines' remaining customers, including those serving the core (residential) market.



[35] Alliance Pipeline Shipper Task Force Policy Group Presentation – April 17, 2009

In denying NGTL's application, clearly the Board recognized the critical nature of the competitive concerns. This proceeding gave rise to the Competitive Pipeline Review Proceeding.

**Q71. Would you not expect the regulator to deny Alliance's application to serve that market?**

**A71.** A denial by the NEB, which regulates Alliance, is much less likely. The NEB has a history of approving competitive pipeline facilities, such as (i) Cyanamid Canada Pipeline (1986), (ii) Alliance Pipelines (1998), (iii) AEC Suffield pipelines (1998), (iv) Coleman Pipeline Project (1998), and (v) Petro-Canada (2001).[36]

**Q72. Is there still a risk of future competition with NGTL in that market?**

**A72.** Yes, if the Integration proposal is unsuccessful. Since NGTL is now regulated by the NEB, it will be able to file a facilities application for the Ft. Saskatchewan area with the federal regulator. In light of the NEB's history of approving competitive facilities, as noted above, a future application by NGTL has a greater likelihood of receiving approval than previously.

Therefore, while ATCO Pipelines faced one principal large competitor in 2003, it now faces two large competitors, both regulated by the NEB, which is more inclined to approve competitive facilities. As a result, ATCO Pipelines' competitive risks have increased significantly since the last generic cost of capital proceeding.

**Q73. Are there other potential competitors to ATCO Pipelines?**

[36] National Energy Board, *Reasons for Decision, Cyanamid Canada Pipeline Inc.,* GH-3-86, December 1986, National Energy Board, *Reasons for Decision, Alliance Pipeline Ltd. on behalf of Alliance Pipeline Limited Partnership*, GH-3-97, November 1998, National Energy Board, *Reasons for Decision, AEC Suffield Gas Pipeline Inc.,* GH-2-98, July 1998, National Energy Board, *Reasons for Decision, Northstar Energy Corporation,* GH-1-98, and National Energy Board, *Reasons for Decision, Petro-Canada,* GH-3-2001, December 2001.

**A73.** Yes. For example, during ATCO Gas' 2003 unbundling hearing (Application 1303682), EnCana expressed an interest in transporting gas directly to the ATCO Gas system, bypassing ATCO Pipelines. Until the exclusivity agreement between ATCO Gas and ATCO Pipelines expires, any gas transported to ATCO Gas is required to go through ATCO Pipelines. However, this exclusivity agreement expires later this year, whereupon other pipelines, including regulated and unregulated (e.g., EnCana) pipelines, may seek to deliver directly to ATCO Gas' market, increasing ATCO Pipelines' market risk.

**Q74. Given the circumstances described above what conclusions can be drawn from Dr. Booth's statement that "in 2003 there was considerable uncertainty surrounding the state of intra-Alberta pipeline competition" and the conclusion that "competitive risk has undoubtedly decreased"?**

**A74.** The opposite is in fact true. The 2003 Generic Cost of Capital proceeding occurred when inter-pipeline competition was just beginning to heat up.

**Q75. Have the competitive issues between ATCO Pipelines and NGTL declined since 2003?**

**A75.** No. As discussed in my direct evidence, there are three key competitive issues ATCO Pipelines faces with respect to NGTL. These are, in order of priority:

(i) Rate Design;
(ii) Investment Policy; and
(iii) Least Cost Alternative (LCA) Policy.

Two of these issues have been settled in favour of NGTL, rate design and investment policy. In Decision 2006-010 (NGTL 2005 Phase II GRA), dated February 21, 2006, the Board accepted NGTL's meter only FT-A toll and its lower cost accountability. Although this decision reduced uncertainty around NGTL's tolls, it increased uncertainty for ATCO Pipelines' ability to retain its delivery customers. NGTL's lower minimum payment requirements relative to ATCO Pipelines results in industrial customers preferring NGTL service over ATCO Pipelines' service.

The third competitive issue, least cost alternative policy, was to be addressed in the Competitive Pipeline Review proceeding. Although the Competitive Pipeline Review has not been terminated, as NGTL is now NEB regulated, resolution is more uncertain.

As regards the least cost alternative policy, the decision by ATCO Pipelines to participate in the East Edmonton Petro-Canada/TBO and the Grande Cache TBO was a question of necessity. If ATCO Pipelines did not offer TBO service, NGTL would physically serve these customers, paving the way for the eventual attraction of other existing ATCO Pipelines' customers with lower tolls and tariff.

There have also been other NGTL competitive initiatives. For example, NGTL's Thunder Extension Permit Application, which was later withdrawn, would likely have resulted in a bypass of ATCO Pipelines' Swan Hills pipeline. NGTL's Smoky River Expansion, placed into service April 2009, will likely attract volumes from ATCO Pipelines' Grande Cache pipelines, as receipt customers bypass ATCO Pipelines in order to avoid dual tolling. In addition, the Board/Commission has put ATCO Pipelines at risk over the life of the Grande Cache TBO contract (Decision 2006-089) and more recently has required ATCO Pipelines to absorb a portion of the revenue losses that result from matching the NGTL FT-A toll over the 10 year life of each of the Shell Canada and North West Upgrading Non-Standard contracts (Decision 2009-027). These examples underscore the nature of the more intensive competition that has prevailed between ATCO Pipelines and NGTL since the last generic cost of capital proceeding.

**Q76. Dr. Booth claims that supply risk for NGTL has declined. Does he refer to ATCO Pipelines' supply risk?**

**A76.** No.

**Q77. Has ATCO Pipelines' supply risk declined?**

**A77.** No. As discussed in my direct testimony, the "EUB's report *Alberta's Energy Reserves and Supply/Demand Outlook 2008-2017* (June 2008) concluded that WCSB gas production peaked in 2001 and conventional gas production would decline by an average of 3.2 percent per year over the forecast period." The February 2009 decision of the Alberta Energy and Utilities Board in the Inquiry into Natural Gas Liquids Extraction Matters (Decision 2009-009, Section 4.2) also supports declining total Alberta gas production from conventional and unconventional sources. The National Energy Board report, *Short-term Canadian Natural Gas Deliverability 2008- 2010,* which was referenced in my direct testimony, indicates that higher decline rates are forecast for areas included in the ATCO Pipelines service territory.

**Q78. In response to ATCO-CAPP-25 in which he was asked whether his conclusion regarding the long-term supply in Alberta was consistent with the EUB's NGL Inquiry decision, Dr. Booth stated that "the EUB did not actually make or support a specific natural gas supply forecast". Is your interpretation of the EUB's findings the same as Dr. Booth's?**

**A78.** No. On page 32 of Decision 2009-009, the EUB stated that the forecasts by participants generally agree with the main trends in the published ERCB forecasts and notes that the 2008 ERCB supply forecast decline is steeper than the 2007 ERCB supply forecast decline. The EUB also stated that all the forecasts show declines in total gas production from conventional and unconventional sources, and that it considers all the forecasts reasonable relative to the ERCB forecasts. Further, the EUB concurred with the general trends for 2018 to 2028 as set out in Figure 3 of the Decision, which graphically established the expected decline in supply.

**Q79. What is the implication of the higher decline rates in ATCO Pipelines' service area relative to other supply areas in Alberta?**

**A79.** The implication is that the alternative sources of supply are at the NGTL connections, which increase ATCO Pipelines' bypass risk.

**Q80. In discussing supply risk, CAPP, at pages 4 and 5 of its written evidence, acknowledges that forecast uncertainty is a risk, but then refers to Dr. Booth's evidence and states that this risk can be reduced by "adjusting depreciation to reflect changes in long term supply forecasts".**

**A80.** Dr. Booth, at page 49 of his written evidence, describes long run risks as the risk attached to the return of capital, refers to depreciation as the return of capital, and then states that "(s)etting the depreciation rate correctly thus modifies the capital recovery or longer term risks".

**Q81. Do you agree with Dr. Booth's position on this issue?**

**A81.** No. As discussed in response to UCA-ATCO-85, as the National Energy Board correctly recognized in RH-2-2004 (National Energy Board, *Reasons for Decision, TransCanada PipeLines Limited*, RH-2-2004, Phase II, April 2005), the cost of capital is intended to compensate for the risk that the best estimate of the economic life as reflected in the depreciation rates may ultimately prove to be wrong. The NEB decision quite correctly concludes that depreciation rates are not used to manage business risk.

**Q82. Dr. Safir states at page 8 of his written evidence:**

> ***Alberta regulated utilities apparently find that formula adjusted ROEs provide a fair enough return as they also continue to make large capital intensive investments.***

**and,**

> ***Beginning in 2003, and extending to 2009, capital expenditures for ATCO Pipelines will exceed $500 million.[16] These large scale investments are contrary to what one would expect if formula adjusted ROEs were not providing utilities with their opportunity cost of capital.***

**Are Dr. Safir's conclusions correct?**

**A82.** No. As regards ATCO Pipelines' specific circumstances, Dr. Safir is referring to ATCO Pipelines' response to CAPP-ATCO-1. This response provides a table of actual capital expenditures by year, split out by various categories. The table shows that only $103 million (or approximately 20% of total capital expenditures) over the seven years related to growth. Nevertheless, if ATCO Pipelines is not willing to provide service to these growth customers, ATCO Pipelines' competitors will, increasing their competitive advantage with respect to ATCO Pipelines' existing customers.

The remaining 80% of capital expenditures relate to work required simply to maintain safe and reliable service to existing customers. Capital spending in 2005 to 2009 for this purpose has been at annual levels two to three times their 2003 level. The resulting increase in rate base with no matching increase in revenue (i.e., higher unit costs and rates[37]) reduces ATCO Pipelines' relative competitiveness and raises its bypass risk.

[37] ATCO Pipelines' North standard customer rates increased by 17.7% on January 1, 2008[37], and by a further 18.7% on December 1, 2008[37]. Similarly, ATCO Pipelines' South standard customer rates increased by 8.3% on January 1, 2008 and by a further 15.5% on December 1, 2008.

**Q83. More generally, how do you respond to the comment by Dr. Safir that "Alberta regulated utilities apparently find that formula adjusted ROEs provide a fair enough return as they also continue to make large capital intensive investments"?**

**A83.** The ATCO Utilities continue to invest, despite the low levels of allowed ROEs and thin equity ratios for a number of reasons, none of which is because they consider the prevailing rates of return "fair enough." Unlike the NEB regulated pipelines, the ATCO Utilities have a legal obligation to serve. At a minimum, the utilities must undertake the capital expenditures required to meet their obligations to provide safe and reliable service. Second, the ATCO Utilities continue to invest to protect the value of the utility systems e.g. to avoid bypass. Third, the utilities invest in their systems in the expectation that they will be allowed returns to which they are entitled under the fair return standard.

## INDIVIDUAL COMPANY RISK DATA FOR A RATED U.S. UTILITIES

| | S & P | | | | Bloomberg | | |
|---|---|---|---|---|---|---|---|
| **Company** | **Debt Rating** | **Business Risk Profile** | **Financial Profile** | **Moody's Debt Rating** | **Raw Beta** | **Adjusted Beta** | **Common Equity Ratio (Total Capital) Avg 2004-2008 (%)** |
| AGL Resources | A- | Excellent | Intermediate | A3 | 0.676 | 0.784 | 41.4 |
| Consol. Edison | A- | Excellent | Intermediate | A2 | 0.572 | 0.715 | 47.9 |
| Dominion Resources | A- | Excellent | Aggressive | Baa2 | 0.855 | 0.903 | 37.3 |
| Duke Energy | A- | Excellent | Intermediate | Baa2 | 0.716 | 0.811 | 55.4 |
| FPL Group | A | Excellent | Intermediate | A2 | 1.035 | 1.023 | 43.5 |
| New Jersey Resources [1/] | A | Excellent | Intermediate | A1 | 0.687 | 0.792 | 48.4 |
| Nicor Inc. | AA | Excellent | Intermediate | A3 | 0.848 | 0.899 | 46.4 |
| Northwest Nat. Gas | AA- | Excellent | Intermediate | A3 | 0.564 | 0.709 | 47.3 |
| NSTAR | A+ | Excellent | Intermediate | A2 | 0.706 | 0.804 | 35.6 |
| Piedmont Natural Gas | A | Excellent | Intermediate | A3 | 0.694 | 0.796 | 47.9 |
| PPL Corp. | A- | Excellent | Aggressive | Baa2 | 0.806 | 0.871 | 37.7 |
| SCANA Corp. | A- | Excellent | Aggressive | Baa1 | 0.777 | 0.851 | 41.6 |
| Southern Co. | A | Excellent | Intermediate | A3 | 0.595 | 0.730 | 41.0 |
| Vectren Corp. | A- | Excellent | Intermediate | Baa1 | 0.710 | 0.807 | 41.7 |
| WGL Holdings Inc. | AA- | Excellent | Intermediate | A2 | 0.817 | 0.878 | 53.2 |
| **Mean** | **A** | **Excellent** | **Intermediate** | **A3** | **0.737** | **0.825** | **44.4** |

1/ For subsidiary, New Jersey Natural Gas

Source:
Standard & Poor's *Issuer Ranking: U.S. Natural Gas Distributors and Integrated Gas Companies, Strongest to Weakest* (March 10, 2009);
Standard & Poor's *Issuer Ranking: U.S. Regulated Electric Utilties, Strongest to Weakest* (March 2, 2009);
www.moodys.com; Bloomberg Betas; S&P Research Insight.

## DCF COST OF EQUITY FOR BENCHMARK SAMPLE OF A RATED U.S. UTILITIES (BASED ON ANALYSTS' EARNINGS GROWTH FORECASTS)

| Company | Annualized Last Paid Dividend | Average Monthly Closing Prices March 2009 | Expected Dividend Yield [1/] | Average I/B/E/S Long-Term EPS Forecasts | DCF Cost of Equity [2/] |
|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) |
| AGL Resources | 1.72 | 26.13 | 6.9 | 4.3 | 11.1 |
| Consol. Edison | 2.36 | 36.32 | 6.7 | 2.5 | 9.2 |
| Dominion Resources | 1.75 | 29.81 | 6.3 | 7.8 | 14.1 |
| Duke Energy | 0.92 | 13.34 | 7.2 | 4.5 | 11.7 |
| FPL Group | 1.89 | 47.13 | 4.4 | 9.6 | 14.0 |
| New Jersey Resources [1/] | 1.24 | 33.05 | 4.0 | 7.0 | 11.0 |
| Nicor Inc. | 1.86 | 31.04 | 6.2 | 2.9 | 9.0 |
| Northwest Nat. Gas | 1.58 | 41.46 | 4.0 | 4.8 | 8.7 |
| NSTAR | 1.50 | 30.21 | 5.3 | 6.0 | 11.3 |
| Piedmont Natural Gas | 1.08 | 24.08 | 4.8 | 7.1 | 11.9 |
| PPL Corp. | 1.38 | 27.11 | 5.7 | 12.3 | 18.0 |
| SCANA Corp. | 1.88 | 28.97 | 6.8 | 4.6 | 11.3 |
| Southern Co. | 1.68 | 29.13 | 6.1 | 5.4 | 11.4 |
| Vectren Corp. | 1.34 | 19.58 | 7.3 | 7.2 | 14.5 |
| WGL Holdings Inc. | 1.42 | 31.39 | 4.7 | 4.0 | 8.7 |
| **Mean** | **1.57** | **29.92** | **5.8** | **6.0** | **11.7** |

[1/] Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (4))
[2/] Expected Dividend Yield (Col (3)) + I/B/E/S Growth Forecast (Col (4))

Source: Standard and Poor's Research Insight, Yahoo.com and I/B/E/S (March 2009)

**INDIVIDUAL COMPANY RISK DATA FOR**
**BBB RATED U.S. UTILITIES**

| Company | S & P Debt Rating | S & P Business Risk Profile | S & P Financial Profile | Moody's Debt Rating | Bloomberg Raw Beta | Bloomberg Adjusted Beta | Common Equity Ratio (Total Capital) Avg 2004-2008 (%) |
|---|---|---|---|---|---|---|---|
| ALLIANT ENERGY CORP | BBB+ | Excellent | Aggressive | Baa1 | 0.985 | 0.990 | 53.7 |
| AMERICAN ELECTRIC POWER | BBB | Excellent | Aggressive | Baa2 | 0.880 | 0.920 | 39.5 |
| ATMOS ENERGY CORP | BBB+ | Excellent | Aggressive | Baa3 | 0.780 | 0.853 | 45.6 |
| CENTERPOINT ENERGY INC | BBB | Excellent | Aggressive | Ba1 | 1.161 | 1.108 | 13.9 |
| CMS ENERGY CORP | BBB- | Excellent | Aggressive | Ba1 | 1.049 | 1.033 | 23.2 |
| DPL INC | BBB | Excellent | Aggressive | Baa2 | 0.500 | 0.667 | 34.3 |
| DTE ENERGY CO | BBB | Excellent | Aggressive | Baa2 | 0.953 | 0.969 | 40.0 |
| FIRSTENERGY CORP | BBB | Excellent | Aggressive | Baa3 | 1.034 | 1.023 | 42.5 |
| GREAT PLAINS ENERGY INC | BBB | Excellent | Aggressive | Baa2 | 0.719 | 0.813 | 48.0 |
| INTEGRYS ENERGY GROUP INC | BBB+ | Excellent | Intermediate | A3 | 0.735 | 0.823 | 48.2 |
| NISOURCE INC | BBB- | Excellent | Aggressive | Baa3 | 0.935 | 0.957 | 42.0 |
| NORTHEAST UTILITIES | BBB | Excellent | Aggressive | Baa2 | 0.832 | 0.888 | 36.1 |
| PG&E CORP | BBB+ | Excellent | Intermediate | Baa1 | 0.773 | 0.849 | 43.6 |
| PROGRESS ENERGY INC | BBB+ | Excellent | Aggressive | Baa2 | 0.709 | 0.806 | 43.6 |
| PUBLIC SERVICE ENTRP GRP | BBB | Excellent | Aggressive | Baa2 | 0.977 | 0.985 | 37.1 |
| SOUTH JERSEY INDUSTRIES INC | BBB+ | Excellent | Aggressive | Baa1 | 0.716 | 0.810 | 46.4 |
| TECO ENERGY INC | BBB- | Excellent | Aggressive | Baa3 | 0.852 | 0.901 | 32.1 |
| WESTAR ENERGY INC | BBB- | Excellent | Aggressive | Baa3 | 0.771 | 0.847 | 45.5 |
| WISCONSIN ENERGY CORP | BBB+ | Excellent | Aggressive | A3 | 0.567 | 0.711 | 40.5 |
| XCEL ENERGY INC | BBB+ | Excellent | Aggressive | Baa1 | 0.682 | 0.788 | 43.0 |
| **Mean** | **BBB** | **Excellent** | **Aggressive** | **Baa2** | **0.831** | **0.887** | **39.9** |

Source:
Standard & Poor's *Issuer Ranking: U.S. Natural Gas Distributors and Integrated Gas Companies, Strongest to Weakest* (March 10, 2009);
Standard & Poor's *Issuer Ranking: U.S. Regulated Electric Utilties, Strongest to Weakest* (March 2, 2009);
www.moodys.com; Bloomberg Betas; S&P Research Insight.

**DCF COST OF EQUITY FOR BENCHMARK SAMPLE OF
BBB RATED U.S. UTILITIES
(BASED ON ANALYSTS' EARNINGS GROWTH FORECASTS)**

| Company | Annualized Last Paid Dividend (1) | Average Monthly Closing March 2009 (2) | Expected Dividend Yield [1/] (3) | Average I/B/E/S Long-Term EPS Forecasts (4) | DCF Cost of Equity [2/] (5) |
|---|---|---|---|---|---|
| ALLIANT ENERGY CORP | 1.50 | 22.68 | 7.0 | 5.95 | 13.0 |
| AMERICAN ELECTRIC POWER | 1.64 | 26.06 | 6.6 | 4.16 | 10.7 |
| ATMOS ENERGY CORP | 1.32 | 22.09 | 6.3 | 5.00 | 11.3 |
| CENTERPOINT ENERGY INC | 0.76 | 9.90 | 9.1 | 18.00 | 27.1 |
| CMS ENERGY CORP | 0.50 | 11.42 | 4.7 | 6.50 | 11.2 |
| DPL INC | 1.14 | 21.47 | 5.7 | 7.43 | 13.1 |
| DTE ENERGY CO | 2.12 | 26.21 | 8.4 | 3.50 | 11.9 |
| FIRSTENERGY CORP | 2.20 | 38.60 | 6.2 | 9.00 | 15.2 |
| GREAT PLAINS ENERGY INC | 0.83 | 12.47 | 7.2 | 7.69 | 14.8 |
| INTEGRYS ENERGY GROUP INC | 2.72 | 24.14 | 12.8 | 13.55 | 26.3 |
| NISOURCE INC | 0.92 | 9.19 | 10.2 | 1.60 | 11.8 |
| NORTHEAST UTILITIES | 0.95 | 20.87 | 4.9 | 8.54 | 13.5 |
| PG&E CORP | 1.68 | 37.83 | 4.8 | 7.10 | 11.9 |
| PROGRESS ENERGY INC | 2.48 | 34.09 | 7.7 | 5.54 | 13.2 |
| PUBLIC SERVICE ENTRP GRP | 1.33 | 26.75 | 5.3 | 6.00 | 11.3 |
| SOUTH JERSEY INDUSTRIES INC | 1.19 | 34.27 | 3.7 | 7.00 | 10.7 |
| TECO ENERGY INC | 0.80 | 24.14 | 3.6 | 8.65 | 12.3 |
| WESTAR ENERGY INC | 1.20 | 16.57 | 7.5 | 3.59 | 11.1 |
| WISCONSIN ENERGY CORP | 1.35 | 38.84 | 3.8 | 9.13 | 12.9 |
| XCEL ENERGY INC | 0.95 | 17.49 | 5.8 | 6.72 | 12.5 |
| **Mean** | **1.38** | **23.75** | **6.6** | **7.2** | **13.8** |

[1/] Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (4))
[2/] Expected Dividend Yield (Col (3)) + I/B/E/S Growth Forecast (Col (4))

Source: Standard and Poor's Research Insight, Yahoo.com and I/B/E/S (March 2009)

## Comparison of Pre-Tax Cost of Capital For A- and BBB-Rated Alberta Utilities

**Case 1:**

| **A-Rated Utility** | | | |
|---|---|---|---|
| Debt | 60% | 6.50% | 3.9% |
| Equity | 40% | 10.50% | 4.2% |
| Cost of Capital | | | 8.1% |
| Tax at 29% | | | 1.7% |
| Pre-Tax Cost of Capital | | | 9.8% |

| **BBB-Rated Utility** | | | |
|---|---|---|---|
| Debt | 64% | 6.85% | 4.4% |
| Equity | 36% | 10.95% | 3.9% |
| Cost of Capital | | | 8.3% |
| Tax at 29% | | | 1.6% |
| Pre-Tax Cost of Capital | | | 9.9% |

**Case 2:**

| **A-Rated Utility** | | | |
|---|---|---|---|
| Debt | 60% | 6.50% | 3.9% |
| Equity | 40% | 10.50% | 4.2% |
| Cost of Capital | | | 8.1% |
| Tax at 29% | | | 1.7% |
| Pre-Tax Cost of Capital | | | 9.8% |

| **BBB-Rated Utility** | | | |
|---|---|---|---|
| Debt | 64% | 8.00% | 5.1% |
| Equity | 36% | 12.60% | 4.5% |
| Cost of Capital | | | 9.7% |
| Tax at 29% | | | 1.9% |
| Pre-Tax Cost of Capital | | | 11.5% |

**Case 3:**

| **A-Rated Utility** | | | |
|---|---|---|---|
| Debt | 60% | 6.50% | 3.9% |
| Equity | 40% | 8.75% | 3.5% |
| Cost of Capital | | | 7.4% |
| Tax at 29% | | | 1.4% |
| Pre-Tax Cost of Capital | | | 8.8% |

| **BBB-Rated Utility** | | | |
|---|---|---|---|
| Debt | 64% | 6.85% | 4.4% |
| Equity | 36% | 9.20% | 3.3% |
| Cost of Capital | | | 7.7% |
| Tax at 29% | | | 1.4% |
| Pre-Tax Cost of Capital | | | 9.0% |

# Break-Even Analysis of Pre-Tax Cost of Capital
# For A- and BBB-Rated Utilities

**Tax Rate of 29%**

| **Case 4:** | | | | **Case 5:** | | | |
|---|---|---|---|---|---|---|---|
| **A-Rated Utility** | | | | **A-Rated Utility** | | | |
| Debt | 60% | 6.50% | 3.9% | Debt | 60% | 6.50% | 3.9% |
| Equity | 40% | 10.50% | 4.2% | Equity | 40% | 8.75% | 3.5% |
| Cost of Capital | | | 8.1% | Cost of Capital | | | 7.4% |
| Tax at 29% | | | 1.7% | Tax at 29% | | | 1.4% |
| Pre-Tax Cost of Capital | | | 9.8% | Pre-Tax Cost of Capital | | | 8.8% |
| | | | | | | | |
| **BBB-Rated Utility** | | | | **BBB-Rated Utility** | | | |
| Debt | 64% | 6.85% | 4.4% | Debt | 64% | 6.85% | 4.4% |
| Equity | 36% | 10.73% | 3.9% | Equity | 36% | 8.78% | 3.2% |
| Cost of Capital | | | 8.2% | Cost of Capital | | | 7.5% |
| Tax at 29% | | | 1.6% | Tax at 29% | | | 1.3% |
| Pre-Tax Cost of Capital | | | 9.8% | Pre-Tax Cost of Capital | | | 8.8% |
| | | | | | | | |
| ROE Differential | | 0.23% | | ROE Differential | | 0.03% | |

**Tax Rate of 25%**

| **Case 6:** | | | | **Case 7:** | | | |
|---|---|---|---|---|---|---|---|
| **A-Rated Utility** | | | | **A-Rated Utility** | | | |
| Debt | 60% | 6.50% | 3.9% | Debt | 60% | 6.50% | 3.9% |
| Equity | 40% | 10.50% | 4.2% | Equity | 40% | 8.75% | 3.5% |
| Cost of Capital | | | 8.1% | Cost of Capital | | | 7.4% |
| Tax at 25% | | | 1.4% | Tax at 25% | | | 1.2% |
| Pre-Tax Cost of Capital | | | 9.5% | Pre-Tax Cost of Capital | | | 8.6% |
| | | | | | | | |
| **BBB-Rated Utility** | | | | **BBB-Rated Utility** | | | |
| Debt | 64% | 6.85% | 4.4% | Debt | 64% | 6.85% | 4.4% |
| Equity | 36% | 10.66% | 3.8% | Equity | 36% | 8.75% | 3.2% |
| Cost of Capital | | | 8.2% | Cost of Capital | | | 7.5% |
| Tax at 25% | | | 1.3% | Tax at 25% | | | 1.1% |
| Pre-Tax Cost of Capital | | | 9.5% | Pre-Tax Cost of Capital | | | 8.6% |
| | | | | | | | |
| ROE Differential | | 0.16% | | ROE Differential | | 0.00% | |