British Columbia Utilities Commission
Generic Cost of Capital Proceeding

IN THE MATTER OF

BRITISH COLUMBIA UTILITIES COMMISSION

GENERIC COST OF CAPITAL PROCEEDING
(STAGE 1)

DECISION

May 10, 2013

Before:

D.A. Cote, Commissioner/Panel Chair
R. Giammarino, Commissioner
M.R. Harle, Commissioner
L.A. O'Hara, Commissioner

TABLE OF CONTENTS

Page No.

TABLE OF CONTENTS

Page No.

TABLE OF CONTENTS

Page No.

TABLE OF CONTENTS

Page No.

.

EXECUTIVE SUMMARY

By Order G-20-12 on February 28, 2012, the British Columbia Utilities Commission (Commission) initiated the Generic Cost of Capital (GCOC) proceeding pursuant to section 82 of the *Utilities Commission Act* to review and determine among other things, the following:

- The setting of the appropriate cost of capital for a benchmark low-risk utility;
- The possible return to an automatic adjustment mechanism (AAM) for setting the return on equity (ROE) for the benchmark utility each year; and
- The establishment of a deemed capital structure and deemed cost of capital methodology, particularly for those utilities without third party debt.

By Order G-48-12 on October 11, 2012, the Commission established the following:

- The proceeding will have two stages; Stage 1 will determine the cost of capital for the benchmark utility and Stage 2 will establish the cost of capital for other utilities as compared to the benchmark.
- Fortis Energy Inc. (FEI) in its pre-amalgamation state will serve as the benchmark utility for the GCOC proceeding; and
- An oral public hearing commencing on December 12, 2012, will be held to determine the cost of capital for the benchmark utility.

Fair Return Standard

The Fair Return Standard is foundational for cost of capital proceedings and has three requirements for a fair and reasonable return on capital: the comparable investment requirement, the financial integrity requirement, and the capital attraction requirement. The Commission Panel, consistent with previous decisions and the regulatory compact, confirms that the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital. In the current proceeding, the Commission Panel has not considered the rate impacts of the revenue required to yield the fair return but has noted that by seeking an optimal capital structure and the opportunity cost of capital, the needs of customers are being served.

Contextual Issues

Three important issues were raised that were contextual in nature; the significance of past cost of capital decisions, the significance of decisions from other jurisdictions and the relevance of the disparity between "allowed" and "actual" ROE.

With respect to past cost of capital decisions and appropriate points of reference, the Commission Panel accepts that the 2009 Decision is a reasonable point of reference with respect to long-term risk as this is the most recent proceeding and has been used extensively by the parties. The Panel also remains open to looking back to the 2006 ROE Decision where appropriate.

With respect to reliance upon data from US jurisdictions, the Commission Panel has determined that it is appropriate to continue to accept the use of historical and forecast data but do not accept that US data should be considered to be the same or be given equal weight as data for Canadian utilities. Concerning Canadian jurisdictional decisions, the Panel acknowledges the importance of considering methodologies, approaches, and regulatory principles related to other jurisdictions' decisions but does not accept the use of results and values for the purpose of calibration.

Concerning the relevance of disparity between FEI's "allowed" and "actual" ROE, the Panel concludes that debt and equity investors, who in their risk assessment consider both long and short-term cash flows as well as risk of financial disruption, will derive some comfort from FEI's positive track record. However, the relevance of disparity between allowed and actual ROE of FEI is entrenched in the regulatory compact, revenue requirements proceedings, and management's proactive approach. Additionally, the Panel is of the view that these differences are assessed in revenue requirement proceedings.

Capital Structure

In determining an appropriate capital structure for the benchmark utility, the Commission Panel considered FEI's long and short-term risk, development of an optimal capital structure, credit ratings and metrics and experiences of other jurisdictions.

The Commission Panel is supportive of maintaining an "A" category credit rating but only to the extent that it can be maintained without going beyond what is required by the Fair Return Standard. The Commission Panel finds that reductions in long-term risk are warranted with respect to provincial climate and energy policies as well as the competitive position of natural gas relative to electricity. While acknowledging that there has been little change in short-term risk since the 2009 Decision, the Panel has determined that only minimal weight can be given to short-term risk as an impediment to earning a fair return. In consideration of both long and short-term risks, the Commission Panel has determined that a reduction in common equity ratio of 1.5 percent to 38.5 percent is appropriate. The Commission Panel considers a 38.5 percent common equity ratio reflects the reduced long-term risk, yet balances this against potential disruption caused by a significant weakening of credit metrics. The awarded common equity ratio falls within the upper end of the range of comparative utilities in other Canadian jurisdictions.

Return on Equity

The Commission Panel considered expert evidence on various model approaches to determine ROE. The Panel finds that the discounted cash flow model and the capital asset pricing model should be given equal weight in determining the ROE of the benchmark utility. No weight was given to the equity risk premium and comparative earnings models. The Commission has determined that an ROE of 8.75 percent inclusive of a 0.50 percent allowance for financial flexibility is appropriate for the benchmark utility. The benchmark utility ROE will be effective January 1, 2013 and will be effective until December 31, 2015, subject to updating as a result applying the AAM formula.

Automatic Adjustment Formula

Consideration was given to re-instituting an AAM formula for annually setting the ROE for a benchmark utility between proceedings, which had been eliminated in the 2009 Decision. In addition, consideration was given to the status of AAMs in other jurisdictions and what optional AAMs might be considered. The Commission Panel has determined that it is appropriate to re-establish an AAM formula noting that it better meets the FRS than giving no consideration to the market changes over the period between ROE proceedings. The Panel has directed that a two variable model considering changes to utility bond spreads and the long-term Canada bond yield be established to determine the benchmark ROE on an annual basis commencing in the 2014 calendar year. Implementation of the AAM will be subject to an actual Canada bond yield of 3.8 percent being met or exceeded. Therefore, the AAM formula will not be in effect as long as the long Canada bond yield is below 3.8 percent.

Cost of Capital – Small Utilities

Stage 1 of the GCOC proceeding considered the cost of capital for the benchmark utility, FEI. Stage 2 will assess the differences in short and long-term risk faced by regulated utilities in British Columbia other than FEI and their impact on the capital structure and ROE for these utilities. The Commission Panel has recommended that the utilities be separated into three groups, each of which will be handled separately. The Commission Panel has also made a number of determinations and findings with respect to the handling of the size factor as a business risk and deemed short and long-term debt interest rates.

1.0 INTRODUCTION

1.1 Background

The 2009 ROE Decision[1] (2009 Decision) was issued concurrently with Order G-158-09 on December 16, 2009. The Order set the return on equity for FEI, the benchmark utility in British Columbia, at 9.5 percent effective July 1, 2009, and the equity ratio at 40 percent effective January 1, 2010. Order G-158-09 also eliminated the AAM, which had been utilized to set the ROE for the benchmark utility annually. Since that Order, there have been no further adjustments to the ROE or capital structure of the benchmark utility.

This Decision for Stage 1 of the Generic Cost of Capital (GCOC) proceeding sets out:

- the new approved ROE and capital structure for FEI;
- the new automatic adjustment formula and the conditions under which it will be in effect; and
- the framework to review the cost of capital for small utilities.

Stating that changes have occurred in the financial markets since the 2009 Decision, the Commission, by Order G-20-12 dated February 28, 2012, initiated the GCOC proceeding pursuant to section 82 of the *Utilities Commission Act* (*UCA*) to review and determine, among other things, the following:

- the ROE and capital structure for a benchmark low-risk utility;
- the possible return to an AAM to set the ROE for the benchmark utility each year; and
- a deemed capital structure and deemed ROE for small utilities, particularly those utilities without short-term debt.

Order G-20-12 established that all public utilities would be considered applicants in the GCOC proceeding and included a preliminary scoping document, which set out a list of matters to be examined and determined within the proceeding. The Order further divided the list of utilities regulated by the BCUC into Affected Utilities and Other Utilities. The Affected Utilities have been so designated given their active participation in previous ROE proceedings or their anticipated interest

[1] In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc. and Return on Equity and capital Structure Decision, December 16, 2009.

in the GCOC proceeding as investor-owned utilities. These utilities were expected to take a lead role in filing evidence for cost of capital matters that may impact them. The Other Utilities are so designated as they have not actively participated in previous ROE proceedings and they were not expected to file evidence in the GCOC proceeding.

On April 18, 2012, the Commission, by Order G-47-12, issued a final scoping document, which set out the purpose and scope of the proceeding. On April 19, 2012, the Commission issued a preliminary draft of the minimum filing requirements. Following submissions by Registered Interveners, the Commission issued Order G-72-12 on June 1, 2012, which set out the minimum filing requirements for those utilities expected to participate and a preliminary regulatory timetable. In an attachment to Appendix A to the Order, the Commission also placed on the record the terms of reference for a Survey of Cost of Capital Practices in Canada prepared by the Commission consultant, the Brattle Group (Brattle Report).

On October 11, 2012, following a procedural conference held on October 4, 2012, the Commission by Order G-148-12 established that in 2012, FEI in its pre-amalgamation state, will serve as the benchmark utility for the GCOC proceeding. The Order also established an oral public hearing to commence on December 12, 2012, to hear the cost of capital for the benchmark utility. In addition, it was determined that the proceeding will have two stages: Stage 1 establishing the ROE and capital structure for FEI the benchmark utility, and Stage 2, establishing a cost of capital for other utilities as compared to the benchmark utility.

1.2 Purpose and Scope of the Generic Cost of Capital Proceeding

The Commission determined the purpose and scope of the GCOC proceeding in Order G-47-12, with certain outstanding matters such as the appropriate utility, which would serve as the benchmark utility, determined by Order G-148-12 dated October 11, 2012. The purpose and scope of this proceeding are as follows:

PURPOSE OF THE PROCEEDING

The main purposes of the GCOC Proceeding are:

I. to establish a method to determine the appropriate cost of capital for a benchmark low-risk utility in British Columbia, commencing January 1, 2013, and to establish how the Benchmark return on equity (ROE) will be reviewed, and if required, adjusted on a regular basis;

II. to establish a generic methodology or process on how to establish each utility's cost of capital based on the cost of capital for a benchmark low-risk utility; and

III. to establish a framework for determining the appropriate cost of capital for other smaller utilities in the province.

SCOPE OF THE PROCEEDING

I. The appropriate cost of capital for a benchmark low-risk utility effective January 1, 2013. Cost of capital includes capital structure, return on common equity, and interest on debt.

II. Establishment of a Benchmark ROE based on a benchmark low-risk utility effective January 1, 2013 to December 31, 2013 for the initial transition year.

III. Whether re-establishment of an ROE automatic adjustment mechanism (AAM) is warranted. If a return to the use of a formulaic ROE AAM is accepted as a result of the GCOC Proceeding, it would be implemented January 1, 2014. If not, a future regulatory process will be set to review the ROE for a benchmark low-risk utility beyond December 31, 2013 on a regular basis.

IV. A generic methodology or process for each utility to determine its unique cost of capital in reference to the benchmark low-risk utility.

V. In certain circumstances, a methodology to establish a deemed capital structure and deemed cost of capital, particularly for those utilities without third-party debt. This would involve setting a methodology on how to calculate a deemed interest rate.

VI. In certain circumstances for those utilities that require a deemed interest rate, a methodology to establish a deemed interest rate automatic adjustment mechanism (Interest AAM). If warranted, the Interest AAM would be implemented for January 1, 2014. If not warranted, setting a future regulatory process on how the deemed interest for a benchmark low-risk utility would be adjusted in future years beyond December 31, 2013.

1.3 Regulatory Process

As noted previously, the Commission retained The Brattle Group to prepare a survey report on the Cost of Capital Practices in Canada. The Brattle Report, filed as Exhibit A2-3 on June 8, 2012, provides a description of the cost of capital estimation methods and the common approaches in implementing the results in Canadian jurisdictions. The Brattle Report was intended to provide context and background for the establishment of the cost of capital of a low-risk benchmark utility in B.C. All parties were provided with the opportunity to file Information Requests (IRs) on the Report.

In accordance with Order G-72-12, the following utilities filed minimum filing requirements:

- FEI, FortisBC Inc. , FortisBC Energy (Vancouver Island) Inc. (FEVI), and FortisBC (Whistler) Inc. (FEW),[collectively (FBCU)];
- Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd. [collectively (PNG)]; and
- Corix Utilities (Corix).

The Industrial Customers Group of FortisBC Inc. (ICG) and the BC Utility Customers comprising the Association of Major Power Customers of BC (AMPC), the British Columbia Pensioners' and Seniors' Organization (BCPSO), and the Commercial Energy Consumers of BC (CEC) were active in the proceeding. Two rounds of IRs with respect to evidence filed by Affected Utilities and one round of IRs on evidence filed by Interveners took place.

The oral public hearing, including an *in camera* session on FBCU's confidential reports, took place over a period of seven days between December 12, 2012 and December 21, 2012. FBCU tendered five witness panels for cross-examination and Corix, BC Utility Customers, and the ICG each had one witness panel for cross-examination.

A list of procedural orders in the GCOC proceeding is included in Appendix A. A list of Appearances is included in Appendix B and Appendix C contains a list of witness panels that gave evidence. Appendix D contains the List of Exhibits. Appendix E contains a risk matrix used in a recent Commission decision with respect to a small utility that is Appendix B to Order C-1-13, Appendix F contains summary tables of ROE estimates by expert witnesses retained by the utilities and ratepayer groups, and. Appendix G is a list of acronyms.

1.4 Approach to Decision

The legal framework for determining a fair return for a regulated utility is called the "Fair Return Standard" and is discussed in Section 2.

There are a number of broader issues of importance, which were raised by this proceeding. These are contextual in nature and include the following:

- importance of past cost of capital decisions;
- consideration of decisions from other jurisdictions; and
- the relevance of the disparity between “allowed” and “actual” ROE.

These issues are discussed in Section 3 and provide the Commission Panel with a context to assist in reviewing and assessing the evidence.

Section 4 deals with an appropriate capital structure given FEI’s level of risk with consideration of credit ratings and metrics and decisions in other jurisdictions. Section 5 considers the appropriate ROE for the benchmark utility with a review of some of the key issues and models employed by the expert witnesses. Section 6 examines potential AAM models and whether there is justification to return to a reliance on such a mechanism. Section 7 considers issues related to cost of capital for small utilities, and Section 8 examines the need for financial models presented in proceedings such as this to have a sound theoretical basis.

2.0 LEGISLATIVE FRAMEWORK – THE FAIR RETURN STANDARD

2.1 Legislative Requirement

The enabling legislation for the BCUC, the *UCA*, provides that a public utility must not make, demand or receive:

(a) an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it in British Columbia;

(b) a rate that otherwise contravenes this Act, the regulations, orders of the commission or any other law.

A rate is "unjust" or "unreasonable" if it is:

(a) more than a fair and reasonable charge for service of the nature and quality provided by the utility;

(b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property; or

(c) unjust and unreasonable for any other reason.[2]

The *UCA*, and other Canadian legislation delegating power to regulatory tribunals, follow what is known as the "Regulatory Compact." In general terms, the Regulatory Compact states that in exchange for an exclusive franchise to serve a defined area:

- a regulated utility must provide safe, reliable, non-discriminatory service to its ratepayers at cost-based rates as prescribed by the regulatory tribunal, and
- the regulatory tribunal must allow the regulated utility an opportunity to earn a fair return on its invested capital.

(Exhibit C4-9, p. 7; BCPSO Final Submission, p. 3)

The approach to determining a fair return on the cost of invested capital in a regulated utility has normally been referred to as the Fair Return Standard (FRS).

---

[2] *UCA* sections 59 (1) (a) (b), 59(5), 60 (1) (a) (b) (i)

2.2 Elements of a Fair Return Standard

The Supreme Court of Canada decision in *Northwestern Utilities Ltd*. v. *Edmonton (City),* [1929] S.C.R. 186, (*Northwestern Utilities*) at pages 192-193 describes the FRS as follows:

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

The Brattle Report notes that the legal decisions, which provide the overarching principles of the FRS, do not prescribe how to determine comparability, how to estimate the cost of capital for the comparable companies, or how to apply those estimates when setting allowable rates. The cost of capital is the expected rate of return in capital markets on alternative investments of equivalent risk. The expected rate of return investors require is based on the risk-return alternatives available in competitive capital markets. In other words, the cost of capital is a type of opportunity cost: it represents the rate of return that investors could expect to earn elsewhere without bearing more risk. (Exhibit A2-3, pp. 2-3)

On page 8 in the 2009 Decision, the Commission endorsed the National Energy Board's (NEB) articulation of the Fair Return Standard in NEB Decision RH-1-2008 where NEB stated:

> "The Fair Return Standard requires that a fair or reasonable overall return on capital should:
>
> - Be comparable to the return available from the application of the invested capital to other enterprises of like risk (comparable investment requirement);
> - Enable the financial integrity of the regulated enterprise to be maintained (financial integrity requirement); and
> - Permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (capital attraction requirement)."

Ms. McShane, the expert witness for FBCU, submitted that the standards for a fair return arise from legal precedents and there are three requirements the utility must:

1. Earn a return on investment commensurate with that of comparable risk enterprises;
2. Maintain its financial integrity; and
3. Attract capital on reasonable terms.

According to Ms. McShane, the legal precedents make it clear that the three requirements are separate and distinct. The FRS is met only if all three requirements are satisfied. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 8)

Dr. Laurence Booth, the expert witness for the BC Utility Customers, submitted that the definition of a fair rate of return was confirmed in *BC Electric* [*Railway Co. Ltd. v. Public Utilities Commission of B.C. et al ([1960] S.C.R. 837)*] when Mr. Justice Lamont adopted the definition of a fair rate of return, put forward in *Northwestern Utilities*.

Dr. Booth submitted that the definition in the *Northwestern Utilities* is referred to as an opportunity cost, in that the fair return is what could be earned by investing in similar securities elsewhere. Only if the owners of a utility earn their opportunity cost will the returns accruing to them be fair, i.e., they will neither reward the owners with excessive profits, nor ratepayers by charging prices below cost. Dr. Booth further submitted that to any modern financial economist, Mr. Justice Lamont's definition of a fair rate of return as an opportunity cost means a risk adjusted discount rate or expected rate of return. (Exhibit C6-12, pp. 7, 8)

2.3 Application of the Fair Return Standard

The Commission Panel observes that the application of the FRS leaves room for disagreement, judgment and discretion. The methods relied upon by various regulators and practitioners therefore differ substantially. For example, while some regulators set rates by determining the weighted-average cost of debt and equity that the regulated company should be allowed to earn on its invested capital (as a whole), others determine separately the cost of equity and possibly the percentage of equity that should be allowed in the regulated company's capital structure.
(Exhibit A2-3, p. 2)

The Panel also notes the words of the Alberta Utilities Commission (AUC) on this subject related to conflicting evidence and applying judgment:

> "....the determination of a fair return on equity for Alberta utilities requires the assessment of three criteria: return on comparable investments, ability to attract capital and maintenance of financial integrity. As noted by Mr. Justice Rothstein in the TransCanada Pipelines decision cited above, the determination of the rate of return on equity for a regulated utility is difficult given that the correct answer is not readily apparent. This determination requires an expert tribunal to apply its judgment in assessing often conflicting evidence and to consider the differing interests and perspectives on risk of debt and equity investors. This exercise is even more complex in Canada, and in Alberta in particular, given the limited number of stand-alone utilities issuing debt and the lack of any utilities that issue equity directly to investors."[3]

The Commission Panel further notes the words of the Federal Court of Appeal's ruling in *TransCanada Pipelines Ltd. v. National Energy Board, 2004 FCA 149* on just and reasonable tolls. It quotes the *Northwestern Utilities* and states:

> "Tolls which reflect a fair return on capital will be just and reasonable to both the Mainline and its users.

It further states:

> To put the matter another way, when the cost of service methodology is used to determine just and reasonable tolls, if the Board does not permit the Mainline to recover its costs because it has understated the Mainline's cost of equity capital, the Mainline will be unable to earn a fair return on equity. The tolls will therefore not be just and reasonable from the point of view of the Mainline's point of view. On the other hand, the tolls must also be just and reasonable from the point of view of the Mainline's customers and the ultimate consumers who rely on service from the Mainline. Therefore, customers and consumers have an interest in ensuring Mainline's costs are not overstated .... And, specific to this appeal, customers and consumers have an interest in ensuring that the Mainline's cost of equity is not overstated."
>
> (TransCanada Pipelines Ltd. v. National Energy Board, 2004 FCA 149, para. 33, 34)

---

[3] AUC 2009 Generic Cost of Capital Decision, November 12, 2009, p. 28

Submissions by Parties

None of the parties disagree with the Fair Return Standard as the applicable test. The Utilities and Interveners, however, disagree on how this test should be applied.

FBCU take the position that the overall rate of return allowed for FEI must be based on the utility's true cost of capital without compromising the legitimate cost of service to achieve lower rates in the short-run. FBCU submit that the combination of allowed ROE and capital structure should permit FEI to maintain credit ratings that are at a minimum in the "A" credit category in varying market conditions. This matter is further addressed in Section 4.5.

FBCU argue that a fair return is not synonymous with the lowest possible return. It pointed out that in the 2006 ROE Decision (2006 Decision),[4] the Commission had articulated that the "lowest possible" was not the appropriate test. Therefore, FBCU submit that the Commission should not rely on evidence on rate impacts and that the view of Dr. Safir, ICG's expert witness, that the outcome of a "fair return" should always favour the lower range is fundamentally inconsistent with the authorities on the FRS. (FBCU Final Submission, pp. 1, 7, 11-12)

The AMPC/CEC do not dispute the definition of the FRS based on the NEB Decision RH-1-2008 and endorsed by the Commission in the 2009 Decision. However, the AMPC/CEC disagree with FBCU's submission that the three requirements listed are the only factors to be considered when deciding what constitutes a fair return, with no consideration of the Commission's broader mandate to balance the interest of customers and regulated utilities. AMPC/CEC submit that when acting as the surrogate for competition, the Commission cannot and must not protect FEI from all business and financial risk by unnecessarily raising the ROE and common equity at the expense of customers; and the Commission must scrutinize whether the cushion FEI asks for is truly necessary to meet the FRS in light of its broader mandate to protect consumers. In Section 4.5 of this Decision, the Commission Panel discusses the application of the FRS and the role of credit metrics in the implementation of the FRS requirements.

---

4 In the Matter of Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. Application to Determine the Appropriate Return on Equity and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism Decision and Order G-14-06, March 2, 2006.

According to AMPC/CEC, Dr. Booth's evidence shows that he recommended a fair return by applying the principle in the FRS that "only if the owners of a utility earn their opportunity cost will the returns accruing to them be fair." In addition, AMPC/CEC state that among other things, Dr. Booth checked his findings against numerous independent, reputable sources which confirmed that his estimates were reasonable. (AMPC/CEC Final Submission, pp. 5-7)

The BCPSO agrees with FBCU's characterization of the FRS and agrees that utilities are entitled to a competitive return as defined in the FRS' three tests regardless of the rate impact. However, BCPSO submits that it is not the same as to say that customer interests carry no weight in setting an appropriate deemed cost of capital as utility customers have an interest in ensuring that the utility's cost of capital is not overstated. BCPSO submit that a fair return is one that takes into account the right of utility customers to pay no more than a fair and reasonable charge for the service provided. Based on its logic, BCPSO submits that the evidence from Exhibit B1-42 which compares the rate impact of a 5 percent change in the equity ratio to a 50 and 100 basis point change in ROE is admissible; and furthermore, if the utility can be provided a competitive return with less rate impact, that option should be chosen. (BCPSO Final Submission, pp. 3-5)

ICG submits that the interests of customers should be paramount to those of the shareholders and reiterates Dr. Safir's testimony that where a range of competitive returns is available for evaluation, the outcome of a "fair return" should always favour the lower range presented. (ICG Final Submission, p. 3)

In Reply, FBCU submit that the Commission would err in accepting ICG's argument that regulation is simply to benefit customers. FBCU submitted that the Commission, in the 2009 Decision, had been explicit that it was not accounting for rate impacts in reaching its decision. (FBCU Reply, pp. 2-3)

Commission Determination

In previous decisions, the Commission concluded that the opportunity to earn a fair return must be provided to each regulated utility as a separate obligation from those service and financing requirements detailed in other sections of the *UCA*. For instance, on page 8 of its 2006 ROE Decision, the Commission said:

> "In coming to a conclusion of a fair return, the Commission does not consider the rate impacts of the revenue required to yield the fair return. Once the decision is made as to what is a fair return, the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital."

The Commission Panel confirms that the approval of rates to meet the FRS is not optional for the Commission. In other words, the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital, which is consistent with the previous ROE decisions and the Regulatory Compact. In determining the fair return, this Commission Panel examines the overall return, i.e., the ROE and the common equity component, allowed to the utility. This Decision reiterates the principle articulated in the 2006 ROE Decision and the 2009 Decision, and argued by FBCU on pages 7 to 9 in its Final Submission, that the Commission does not consider the rate impacts of the revenue required to yield the fair return. However, by seeking an optimal capital structure and the opportunity cost of capital we are serving the needs of the customer.

While this Commission Panel has not considered the rate impacts of the revenue required to yield the fair return *per se*, we are of the view that the capital structure of the utility should be set efficiently and, therefore, there is value in finding an optimal capital structure. Exhibit B1-42 provides comparative information on revenue requirements for FEI based on either a change in equity thickness or a change in ROE. The ICG submits that the Commission should reduce the ROE before reducing the capital structure of FEI. (ICG Final Submission, p. 4) In this regard, the Commission Panel finds the information on rate impacts as presented in Exhibit B1-42 useful. An optimal capital structure is discussed further in Section 4.4.

3.0 CONTEXTUAL ISSUES

This section considers important issues raised by this proceeding that are contextual in nature; they include:

- The significance of past cost of capital decisions;
- The relevance of US data and the significance of decisions from other jurisdictions; and
- The relevance of the disparity between "allowed" and "actual" ROE.

3.1 Past Cost of Capital Decisions

An important issue arising within the 2012 GCOC proceeding is whether a previous cost of capital decision is an appropriate reference point against which evidence in the current proceeding can be compared. Specifically, the questions facing the Commission Panel are: (1) whether a reference point is required, and (2) in the event it is, what reference point would be most appropriate and to what extent should it be relied upon in the Commission Panel's decision - making process. Within this proceeding, the primary comparative reference point has been the 2009 Decision, which has been relied on to illustrate changes in capital markets as well as changes in short and long-term risk since that time. Each of these referenced areas will be discussed in turn.

Submissions by Parties

3.1.1 <u>Changes in Capital Markets</u>

Throughout this proceeding, the FBCU have relied upon and underlined the Commission's statement that changes have occurred in capital markets since the 2009 Decision was issued. They have taken the position that capital markets are similar (albeit for different reasons) to what they were in the fall of 2009 when the previous cost of capital proceeding took place. The FBCU have relied very heavily on the 2009 Decision as a reference point for the current proceeding and have provided comparisons between what they believe exists today as opposed to conditions which existed at the time of the 2009 Decision. FBCU have relied upon the opinion evidence prepared by two of their expert witnesses, Ms. McShane and Mr. Engen, which showed that many of the key indicators of conditions within capital markets are similar and in some cases worse than the same indicators reflecting capital markets late in 2009. FBCU maintain that the experts along with market indicators and Bank of Canada published information all suggest that equity capital markets in Canada are challenging and volatile and the market cost of equity has risen since 2009. In summary, FBCU maintain that current market conditions provide no basis for reducing FEI's overall return as argued by interveners. (FBCU Final Submission, pp. 1-2, 16-30)

ICG takes issue with FBCU on their choice of 2009 as an appropriate reference point and argue that a more appropriate reference point was the 2006 Decision. ICG submits that the 2009 Decision did not appropriately balance the interests of customers and shareholders and gave inappropriate weight to the interests of shareholders. Moreover, ICG submits that the 2009 Decision represented a significant departure from previous Commission cost of capital decisions. With respect to its Canadian peers, ICG points out that the weighted equity return component was materially lower (by 0.47) in 2005 through 2009 and materially higher (by 0.57) in the 2010 to 2012 period. ICG argues that the 2009 Decision should not be a point of reference for this decision given a steady decline in FEI's business risks since 2005. (ICG Final Submission, pp. 11-12)

BCPSO also takes issue with the use of the 2009 Decision as a reference point for this decision, expressing concern as to whether the capital market conditions comparator dates are consistent across the two proceedings. BCPSO submits that the current proceeding is forward looking with respect to capital conditions and snapshot-style evidence of past capital conditions is of limited value. In its view, the economic tests such as equity risk premium (ERP), comparable earnings (CE) and discounted cash flow (DCF) provide a better basis in assessing cost of capital stating that they "are more precise, forward looking, and can be made industry or company specific." The primary value of evidence relating to general market conditions lies in the trends it demonstrates. (BCPSO Final Submission, p. 6)

AMPC/CEC submit that regulators do not base a cost of capital decision on immediate circumstances only. They assert that the Commission will consider economic and financial conditions occurring since the last hearing and will also consider the outlook on a going forward basis. Referring to Mr. Engen's S&P/TSX Composite Index 10 Year Performance data, AMPC/CEC state that the difference now "is that the last few years have witnessed the market hold or increase ground it recovered, whereas in the lead up to the 2009 hearing, it had just suffered a dramatic crash." They further point out the FBCU argument that capital markets are similar to what they were in 2009 is in conflict with their own witnesses' (Ms. McShane and Dr. Vander Weide) DCF calculations, which have declined considerably since the close of evidence in the last hearing. (AMPC/CEC Final Submission, pp. 28-29; Exhibit B-1-9-6, FBCU Evidence, p. 14, updated in Exhibit B-1-49)

In Reply to ICG, the FBCU state that the choice of 2009 as a point of comparison is because that proceeding is where the Commission most recently assessed FEI's business risk. To disregard this in favour of the 2006 Decision because ICG preferred the outcome in FBCU's view is indefensible. (FBCU Reply, p. 21)

Concerning the AMPC/CEC's submissions regarding the inconsistency in capital markets being similar to 2009 and FBCU's witnesses' DCF calculations, the FBCU state the following:

- Mr. Engen's evidence relates to the overall capital market and trends in the market cost of equity which indicate the market cost of equity is higher today.
- Ms. McShane's and Dr. Vander Weide's DCF calculations relate to a narrow segment of the overall market and deal specifically with FEI's cost of equity. (FBCU Reply, p. 5)

3.1.2 Changes in Long-Term Risk

While there has been considerable disagreement with respect to relying upon 2009 capital markets as a reference point for comparison, there has been little concern raised by the parties with respect to using the 2009 Decision as a reference for changes in long-term risk. Both the FBCU and interveners have relied heavily on what has changed since 2009 and in some cases referred back to the period prior to the 2006 Decision as a source of comparison.

Commission Discussion

The Commission Panel accepts that many of the indicators reflecting the current state of the capital markets are similar to what they were in 2009. This, however, does not mean that the conditions under which the 2009 Decision was made are the same as they are today. As noted in Mr. Engen's evidence, the current period is characterized by concerns for a sustained US economic recovery, fears of an economic slowdown related to weak economic data from the US and the European Union and the European sovereign debt crisis, among other things. These are not at all descriptive of the period in latter 2009. (Exhibit B1-9-6, Appendix E, Engen Evidence, pp. 7-8) Moreover, as pointed out by AMPC/CEC, since that time markets have demonstrated a degree of stabilization in sharp contrast to the situation preceding the 2009 Decision which followed a dramatic crash. Therefore, while there are some similarities between the current period and late 2009, the Panel is of the view there are significant differences. By contrast, the markets, while maintaining volatility, have experienced a few years of comparative stability and the investor has been distanced from the financial conditions characterizing the period leading to the 2009 proceeding.

The Commission Panel is mindful that many of the key indicators of capital market conditions are similar to those of 2009 but does not consider them alone to be determinative in reaching a decision on the cost of equity. While considering changes in capital markets, pricing models some of which reflect the market outlook, are very important in reaching a determination on the appropriate rate of return in this proceeding.

The Commission Panel does accept that the period leading up to the 2009 Decision is a reasonable point of comparison with respect to changes in long-term risk as this is the most recent proceeding and notes that this has been used extensively by the parties. However, the Panel remains open to looking back further to the 2006 Decision where appropriate. In the view of the Panel, a determination on the degree of change in long-term risk is a much more discrete process. It is dependent upon an assessment of the level of risk, which exists in the current circumstances as compared to those which existed at a previous point in time. Therefore, we consider the periods prior to both the 2009 Decision and the 2006 Decision as appropriate reference points in assessing the level of long-term risk faced by FEI.

The Commission Panel does not accept ICG's argument that the 2009 Decision fails to appropriately balance the interests of customers and shareholders. In the view of the Panel, there is no value in re-examining the 2009 Decision nor is there evidence to support the need for doing so.

3.2 Consideration of Other Jurisdictions

Throughout the evidentiary portion of this proceeding there has been considerable reliance among the parties upon data and cost of capital decisions from both US and Canadian jurisdictions. The Commission Panel considers these separately as the issues related to each differ.

3.2.1 Relevance of US Data and Decisions

In the 2006 Decision, two issues related to reliance upon US data in cost of capital proceedings were dealt with by the Commission:

1) Opportunities exist for investors to commit capital on a global basis. The Commission Panel noted that there was considerable foreign exchange risk and was not convinced that the Federal Government's easing of foreign content in retirement portfolios was sufficient reason to raise the equity return of a utility.
2) The necessity of looking beyond Canadian data in measuring the risk premium. The Commission accepted the use of historical and forecast data for US utilities "when applied as a check to Canadian data; as a substitute for Canadian data when those data do not exist in significant quantity or quality; or as a supplement to Canadian data when Canadian data give unreliable results." (2006 Decision, p. 50)

In the 2009 Decision, the Commission accepted the use of historical and forecast data of US utilities as outlined in the 2006 Decision. In addition, the Commission supported the need for utilities to compete in a global marketplace and reiterated its acceptance of the use of historical and forecasting data. In the 2009 Decision, the Commission also noted the lack of relevant Canadian data and considered the potential for US gas utilities to act as a proxy in the determination of cost of capital and credit metrics. (2009 ROE Decision, pp. 15-16)

Submissions by Parties

In the current proceeding, the FBCU take the position that the Commission should find that US data remains useful and that US utilities can be appropriate comparators based on total investment risk. In support of this, they rely on the evidence of Ms. McShane and Dr. Vander Weide who make the following assertions:

- The operating, regulatory and business environments for US and Canadian regulated companies are generally similar.
- Capital markets in Canada and the US are significantly integrated and the cost of capital environment is similar.

In further support of their argument, the FBCU note that Dr. Safir acknowledged the integration of capital markets in his evidence and utilized US companies in his Capital Asset Pricing Model (CAPM) and DCF analysis. Further, the FBCU argue that Dr. Booth, in spite of his concern with the use of US data, conceded there was a high degree of integration between US and Canadian markets. (FBCU Final Submission, pp. 96-97)

AMPC/CEC's witness Dr. Booth raised two concerns with the use of US data:

- US financial markets exhibit greater risk than Canadian markets and have generated higher premia in the past.
- Regulatory implementation differs even though US and Canadian principles of regulation are the same.

(Exhibit C6-12, Dr. Booth Evidence, Appendix B, p. 106)

AMPC/CEC submit that there is ample support for Dr. Booth's assertion that US markets are riskier than those in Canada. They point out his evidence demonstrates that over the period 1926-2011, US returns showed greater volatility than Canadian returns and the risk premium was higher in the US than the equivalent in Canada. They further submit that during Ms. McShane's cross-examination, she agreed that a typical US utility could be viewed as higher risk than a Canadian one and point out that her report aligns with Dr. Booth's as it presents a historical risk premium of 4.7-4.8 percent for Canada compared to 5.5-5.7 percent for the US. (AMPC Final Submission, p. 46) Concerning the difference between Canada and the US with respect to the implementation of regulatory principles, AMPC/CEC state that the Commission in the 2009 Decision was cognizant of the danger of relying on US comparables and cites the following statement of the Commission Panel in that decision:

> "The Commission Panel agrees with Dr. Booth that "significant risk adjustments" to US utility data are required in this instance to recognize the fact that TGI possesses a full array of deferral mechanisms which give it more certainty that it will, in the short term, earn its allowed return than the Value Line US natural gas LDC enjoy." [emphasis added by AMPC/CEC]

Additionally, AMPC/CEC point to Dr. Booth's finding that Canadian utilities have higher bond ratings in spite of poorer financial ratios, which in his view reflects the importance bond rating agencies place on the differing regulatory approaches in Canada and the US. In summary, AMPC/CEC submit that the Commission should continue to approach US data based results with caution, adjusting them downward to reflect differences in financial and regulatory contexts between the two countries. (AMPC/CEC Final Submission, pp. 46-47)

FBCU argue that the evidence does not support a downward adjustment to US results and state the following:

> "Since the financial crisis, long term interest rates have been similar in Canada and the US across a broad range of bond types, equity market volatility has been virtually identical, and market risk premium surveys show virtual identical values." (FBCU Reply, p. 28)

None of the parties have suggested that the Commission should put no weight on US data and decisions.

Commission Determination

The Commission Panel reaffirms the 2009 Decision determination on when to use historical and forecast data for US utilities. Canadian utilities need to be able to compete in a global marketplace and be allowed a return for them to do so. In addition, the Panel accepts that there continues to be limited Canadian data upon which to rely and considers that there may be times when natural gas companies operating within the US may prove to be a useful proxy in determining the cost of capital. **Accordingly, we have determined that it is appropriate to continue to accept the use of historical and forecast data for US utilities and securities as outlined in the 2006 Decision and again in the 2009 Decision.**

In making this determination the Commission Panel would like to be clear that while we accept there are similarities between the two jurisdictions, we do not accept that US data should be considered to be the same or necessarily be given equal weight as the data for Canadian utilities. Canadian investors considering US utility investments are subject to currency exchange risk that would not be the case with Canadian utility investments. Additionally, the US regulatory environment while similar is not identical to that of Canada. The 2009 Decision's reference to the array of deferral mechanisms resulting in greater certainty for the Canadian utility is just one example of potential differences between the jurisdictions. Moreover, Ms. McShane has acknowledged under cross-examination that the universe of US utilities is focused on vertically integrated utilities and, to the extent that there is a smaller number of Canadian investor-owned, vertically integrated utilities, the typical US utility could be viewed as higher risk than the typical Canadian utility. (T3:466-467) Therefore, in the view of the Commission Panel, the use of US data must be considered on a case by case basis and weighed with consideration to the sample being relied upon and any jurisdictional differences which may exist.

3.2.2 Consideration from other Canadian Jurisdictions

Throughout this proceeding the parties have chosen to utilize information and related decisions from other Canadian jurisdictions as support for the position they have taken on an issue. The Commission Panel notes that decisions in all jurisdictions result from the judgment of evidence specific to a region or a particular utility that in each case is unique. To the extent that the ROE and equity thickness of a specific utility in another jurisdiction can be used as a comparator, we are open to considering it if it helps inform our decision. However, considerable reliance on decisions from other jurisdictions in our view would lead to circularity that would ensure that only the status quo is maintained -- perhaps at the risk of common sense. The Commission Panel acknowledges the importance of considering the methodologies, approaches and regulatory principles related to other jurisdictions' decisions. However, we do not accept that it is appropriate for results and values to be used for the purpose of calibration in B.C.

3.3 Relevance of Disparity between "Allowed" and "Actual ROE"

3.3.1 Outline of the Issue

As described in Section 2.1, when setting a rate under the subsection 60 of *UCA,* the Commission must have due regard for, among other things, whether the rate is insufficient to yield fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property. This standard does not mean, however, that a utility must be guaranteed its allowed return on equity. It simply means that a utility must be given an opportunity to earn this return. In any particular year, the actual ROE earned may be below or above the allowed ROE. The rates are set based on a forecast revenue requirement for the year, which includes a provision for the allowed ROE, grossed up for income taxes. The utility's actual performance during the fiscal year will determine how close the actual ROE will be to the allowed ROE.

Short-run risks in general relate to a utility's ability to annually earn its allowed return on equity. The issue for the Panel, therefore, is to determine the relevance of the difference of realized and allowed ROE. From the investors' perspective, this risk relates to the relative stability of year-to-year variations in earnings or cash flows and the value of those cash flows. Therefore, the Panel first has to assess the relevance of the disparity between "allowed" and "actual" ROE in relation to the question of whether FEI faces any short-run risks. FEI has a track record of generally achieving, and often exceeding, the allowed ROE in any particular year. Does this strong track record imply FEI having "no material short-run risk, or the risk of return on capital" as claimed by Dr. Booth? (T8:1464)

FEI's track record was explored extensively in the proceeding as shown below:

- From 2002 to 2011, there was only one year when the actual ROE was below the allowed ROE, whether assessed on a pre or post earnings sharing mechanism basis. This year was 2010, when 9.42 percent was achieved as compared to the 9.50 percent allowed, resulting in a net income variance of $1.2 million. (Exhibit B1-20, BCUC 1.95.1)
- A similar trend is also apparent from 1994 to 2001. (Exhibit B1-10, BC Utility Customers 1.2.1; Exhibit C6-12, pp. 27-29)
- FBCU stated that the data set used by Dr. Booth is largely from years in which a Performance Based Rate (PBR) mechanism was in place for FEI. During the PBR period, O&M and capital were set through a formula, not based on forecast spending. The PBR formula approach was designed to result in savings to be shared with customers, primarily from the operational consolidation of three separate utilities. The Commission–approved framework expressly anticipated earnings that were above the allowed ROE. FBCU argue that when the periods under PBR are excluded, the variances between FEI's achieved return and allowed ROE from 1994 to 2011 were not that significant. (FBCU Final Submission, p. 40; Exhibit B1-20, BCUC 1.96.1.1)
- For the PBR period 2004 to 2009, after sharing, the average ROE over the period is .67 percent over the allowed ROE. (Exhibit B1-32, Rebuttal Evidence, p. 3)

Submissions by Parties

FBCU submit that the relative consistency of utility sector earnings in Canada tends to suggest lower short-term risk than for non-regulated companies, but “is not synonymous with an absence of short-term risk.” (FBCU Final Submission, p. 39)

ICG submits that the Commission Panel should not accept that consistent over-earnings can be explained by PBR, and that consistent over-earning is attributable to how effectively FEI manages the regulatory risk, which it claims is its largest risk, not how effectively FEI operates the utility. ICG further argues that one should think of over-earnings during the PBR period as a regulatory benefit that can be enhanced to provide increased earnings that exceed the Fair Return Standard, and that “…the historic returns suggest that FBCU have come to expect returns that exceed a fair return.” (ICG Final Submission, p. 16)

AMPC/CEC first observe that FEI has not experienced any significant risk as “the shareholder has not cumulatively lost any money whatsoever since 1994.” AMPC/CEC submit that “year after year, FEI continues to face very little short-run risk, such that this pattern of consistent overearnings is clearly a long-term phenomenon.” (AMPC/CEC Final Submission, p. 9)

In Reply, FBCU submit “the similarly long track record among Canadian utilities of achieving or exceeding their allowed ROE suggests that Canadian regulators have long recognized that it is reasonable for a well-managed utility to be able to achieve its allowed ROE on a consistent basis.” (FBCU Reply, p. 10)

Commission Determination

The Panel notes that FBCU did not explain why, even after allowance for the sharing mechanism, the over earnings have continued. For instance, in 2011 the actual ROE was 10.15 percent as compared to the 9.50 percent allowed. Consequently, the Panel observes a noteworthy asymmetry between allowed and actual ROEs that is apparent in the frequent occurrence of annual overearnings in contrast to very few years of under earnings.

In the view of the Panel, the differences in actual and allowed ROE relate to revenue requirements and are influenced by management's ability first to forecast and then to control costs for each test period.

The Commission Panel concludes that debt and equity investors, who in their risk assessment consider both long and short-term cash flows as well as risk of financial disruption, will derive some comfort from the track record of FEI. However, there is no evidence to suggest they are likely to make a major distinction between short-term and long-term risk. Accordingly, the relevance of disparity between allowed and actual ROE of FEI is entrenched in the regulatory compact, revenue requirements proceedings, and management's proactive approach.

4.0 CAPITAL STRUCTURE

4.1 Definition of Risk

Dr. Booth has described the most basic definition of risk as “the probability of incurring harm, which in a financial sense means losing money.” Ms. McShane agreed with this definition noting that it was consistent with her own testimony which defined risk as the probability that the utility’s future returns (including the return on and of capital) will fall short of returns that investors expect and require. Mr. Dall’Antonia put a finer point on it as he described a loss as not earning a fair return or more specifically, a loss is anything that is less than the allowed ROE. (Exhibit B6-12, Dr. Booth Evidence, p. 26; Exhibit B1-15, AMPC 1.4.1; T2:123-124)

The Commission Panel takes no issue with the basic definition of risk as provided by Dr. Booth. However, for this Decision, the Commission Panel views risk as the probability that future cash flows will not be realized or will be variable resulting in a failure to meet investor expectations. In addition, the Panel recognizes the risk of potential financial disruption. We also accept the distinction outlined in both the 2006 Decision and the 2009 Decision where investment risk was described as comprising the sum of business risk, financial risk and regulatory risk.

Both Ms. McShane and Dr. Booth addressed business risk in terms of short-term and long-term risks, a distinction the Commission Panel considers appropriate. Each of these is discussed separately in Sections 4.2 and 4.3.

Dr. Booth has described short run utility risk as the risk of earning a return on capital and long run utility risk as the risk of earning a return of capital. (Exhibit C6-12, p. 25) Ms. McShane comments that both the capital structure and the ROE incorporate elements of long-term and short-term risks. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 39) The Commission Panel does not disagree with Ms. McShane but notes that long-term risk, which Ms. McShane outlines as being of primary importance to the utility investor, is primarily reflected in the equity structure determined for FEI considering the investors’ ability to recover their invested capital. This is because if the underlying risk decreases, more debt can be issued; if it increases, the common equity ratio would increase resulting in less debt. Therefore, as pointed out in the 2009 Decision: “The assessment of risks has a significant bearing on the application of the fair return standard and the determination of an appropriate common equity ratio for regulatory purposes."

4.2 FEI's Long-Term Risk

In the 2009 Decision, eight factors that influenced FEI's long-term risk were identified. They were:

1. Provincial Government climate and energy policies;
2. The effect of aboriginal rights issues;
3. The competitive position of natural gas relative to electricity;
4. Percentage of new construction being captured by Terasen Gas Inc. (TGI);
5. Natural gas vs. Electricity in high density housing;
6. The impact of Alternative Energy Sources on TGI;
7. Changes in demand related to fuel switching; and
8. Use of natural gas per customer account.

FBCU has stated that the same risk factors are at play in the current proceeding, although they have been expressed and organized somewhat differently. (FBCU Final Submission, pp. 47-48)
For the purposes of examining the long-term risk of FEI, items 4 and 5 related to the capture rate of new construction and the energy choice for high density housing are combined under the more general heading "Customer Growth." Items 7 and 8 related to use per customer and fuel switching related demand are also combined under the new "Market Demand and Throughput" heading. In addition, two new factors which received little or no coverage in the 2009 proceeding are addressed: "Supply Risk" and "Regulatory Risk."

4.2.1 Provincial Government Climate and Energy Policies

In the 2009 Decision, the provincial government climate and energy policies of the previous few years played a significant role. During the period leading up to the proceeding, the provincial government published the "BC 2007 Energy Plan," introduced numerous pieces of legislation (principally in the area of greenhouse gas emissions reduction) and in 2008 implemented the BC Carbon Tax. In the 2009 Decision, the Commission was in agreement with TGI's position that the climate change legislation had created a level of uncertainty which did not exist during the 2005 hearing and stated that the change in government policy "will quite probably cause potential customers not to opt for natural gas and persuade potential retrofitters to opt for electricity." (2009 Decision, pp. 36-38)

Submissions by Parties

The Commission Panel notes that there is considerable disagreement among the parties concerning the level of risk related to provincial government climate and energy policies. In the current proceeding, FBCU have ranked political risks in the number 2 risk category and submit that the risks associated with policy and legislation are equal to if not greater than in 2009. FBCU note that all of the legislation and policy relied upon by the Commission in the 2009 Decision remains in place and the introduction of the *2010 Clean Energy Act (CEA)* has had the following impacts:

- It has precluded natural gas utilities from using incentives to promote fuel switching (electricity to gas).
- It has required the Commission to account for enumerated energy objectives in the course of considering certain types of applications.

(FBCU Final Submission, pp. 53-56)

Both BCPSO and AMPC/CEC submit that conditions are far more favourable today and the resulting political risks are much lower today than TGI portrayed in 2009. In support of these submissions, they point to a number of factors:

- the lack of plans to increase the carbon tax;
- the introduction of the BC Natural Gas Strategy and its support of natural gas as a transportation fuel; and
- a collapse of the Western Climate Initiative and lack of progress on emissions-trading initiatives.

(BCPSO Final Submission, pp. 15-16; AMPC Final Submission, pp. 22-23)

Commission Determination

The Commission Panel finds that the risks related to provincial government climate and energy policy are less significant when compared to the period leading up to the 2009 Decision. At the time of the 2009 proceeding, there was considerable concern and uncertainty related to provincial energy policies, how they would be shaped in the future and what impact this would have on Terasen's gas utilities. In addition, the Commission placed importance on the Nyboer Report as reflected in the following statement:

> "In addition, the Commission Panel considers that the Nyboer Report presents a scenario that did not exist in 2005 under which the three Terasen utilities might not earn a return of their capital. The scenario that now exists is described in a publication of a reputable consulting group which appears to have the attention of policymakers." (2009 Decision, p. 37)

The Commission Panel does not consider the current environment to be as threatening to FEI as it was perceived to be in the period leading to the 2009 Decision. As BCPSO points out, there are no plans to raise the carbon tax beyond the current $1.50 per GJ level and as AMPC/CEC reports, the Western Climate Initiative has collapsed and emission trading has become a dormant issue. These all reflect a less threatening current environment and with it, a lessening of risk associated with provincial government climate and energy policies.

4.2.2 Aboriginal Rights

In the 2009 Decision, the Commission Panel acknowledged that risks posed by First Nations did not exist previously and to the extent that they were currently perceived, represented an increase in risk over natural gas local distribution companies operating in other provinces. However, the Commission did not consider that risks posed by First Nations cast doubt over Terasen Gas Inc.'s "ability to earn a return on or of its capital." (2009 Decision, p. 37)

Submissions by Parties

FBCU acknowledge that aboriginal rights issues, which they rank in category 2, are much the same now as they were in 2009 and note that this issue was not addressed by the parties in IRs or at the hearing. (FBCU Final Submission, p. 49)

BCPSO argue the amount of aboriginal rights risk should be reduced relative to 2009, given the FBCU experience and understanding of aboriginal rights and title claims resulting from First Nation consultations tied into CPCN Applications. (BCPSO Final Submission, p. 17)

AMPC/CEC submit that this risk remains unchanged from 2009 where it was given no weight and this remains appropriate. (AMPC/CEC Final Submission, p. 24)

Commission Determination

The Commission Panel agrees with the FBCU and AMPC/CEC and find that there is no evidence to suggest that there has been a significant change to risk associated with aboriginal rights based on the evidentiary record of this proceeding. We also concur with the 2009 Decision that the risk associated with aboriginal rights has little impact on the FEI's ability to earn a return.

4.2.3 Competitive Position of Natural Gas Relative to Electricity

The competitive position of natural gas to electricity is an existing risk which bears scrutiny at each cost of capital proceeding. In the 2009 Decision, the Commission Panel took note of the interveners' position that the risk related to the competitive price of natural gas and electricity had diminished since 2005. However, the Panel considered that the competitive edge which existed was dependent on too many significant variables to be considered permanent. (2009 Decision, p. 36)

Submissions by Parties

The FBCU acknowledge that natural gas prices have fallen but submit that this occurred prior to the 2009 Decision and take no issue with the fact that the development of shale gas is a "game changer" or that there has been an increase in electricity prices. They do take issue with Dr. Booth's conclusion that long-term business risk has declined since 2009 and argue that his reliance on considerations related to cost-effectiveness paints an incomplete, distorted view of FEI's overall competitive position. FBCU make the following arguments in support of their position:

- Natural gas prices fell substantially prior to the 2009 hearing due to shale gas development and this was reflected in the evidentiary record leading to the 2009 Decision.
- Volatility in natural gas prices affect natural gas to electricity competitiveness and has increased due to the suspension of hedging instrument tools resulting from the 2011 Price

Risk Management Decision (PRMP Decision).[5] Looking ahead to 2017 there is a wide potential price range for natural gas based on the AECO Forward Curve. (see Figure 2 below)

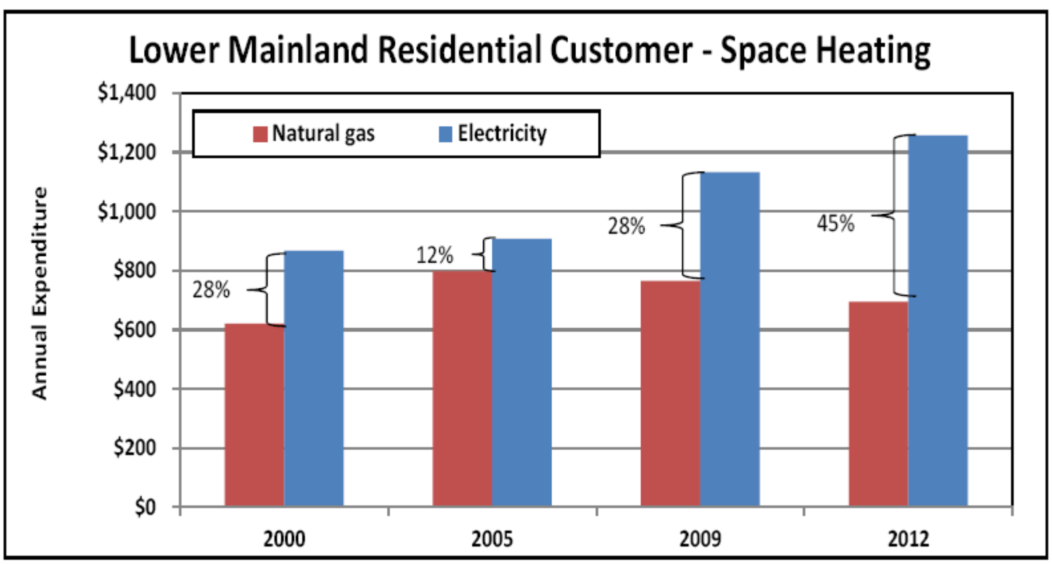
- The price of the natural gas commodity has decreased but the delivered cost of natural gas remains almost the same as 2009.
- Higher capital costs for natural gas heating materially diminish the operating cost advantage of natural gas over electricity.
- Non-price factors such as the desire to create a smaller carbon footprint have resulted in more customers being willing to adopt lower carbon and renewable energy sources.

(FBCU Final Submission, pp. 57-71)

ICG, relying on Figure 1 below, argues that there has been a significant improvement with respect to cost competitiveness between natural gas and electricity since both the 2005 and the 2009 proceedings.

Figure 1: Estimated Annual Expenditure

Figure 1: Estimated Annual Expenditure for FEI Lower Mainland Residential Customer – Natural Gas and Electricity for Space Heating



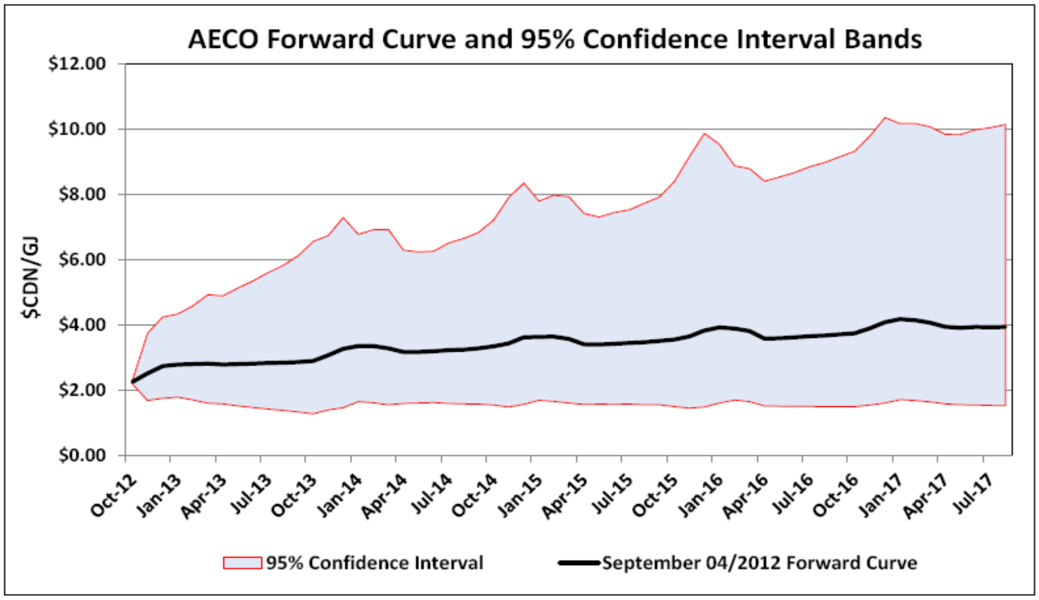
(Source: Exhibit B1-11, FBCU Response to BC Utility Customers, 1.4.2)

ICG contends that shale gas has been a game changer for natural gas prices, which has resulted in a "seismic" shift in the competitiveness of natural gas versus electricity. (ICG Final Submission, p. 11)

---

5 Order G-163-11

Figure 2: AECO Forward Curve



(Source: Exhibit B1-20, BCUC 1.105.1)

BCPSO notes that there has been no change in FBCU's rating of capital cost and it is the same as in 2009. It argues there is no evidence that the effect of higher capital costs will offset any competitive gain made through lower commodity prices. Further, BCPSO submits that the AECO Forward Curve relied upon by FBCU demonstrates only an increasing level of price uncertainty over time, not volatility. BCPSO also takes issue with the FBCU claim that there is effectively no reduction in the customers overall bill. The important comparison is not natural gas against itself but against electricity, and this comparison is very favourable to FEI. (BCPSO Final Submission, pp. 9-10)

AMPC/CEC state that price is a key determinant of natural gas competitiveness and deserves the greatest weight when considering changes to FEI's business risk. In answer to FBCU's claim that the delivered cost of natural gas is similar to 2009, AMPC/CEC argue that prices are at or near a ten-year low and by FBCU's evidence (in Figure 3 below) are lower than 2009 and even more so when compared against 2005. (AMPC/CEC Final Submission, pp. 11-13)

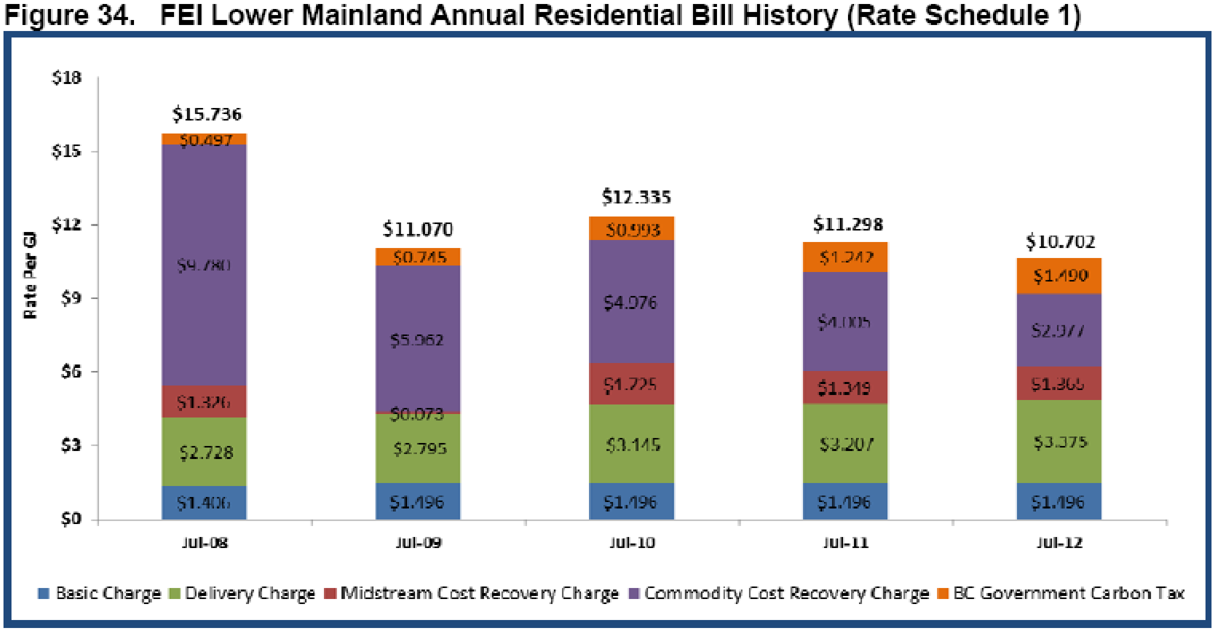
AMPC/CEC assert that the volatility is manageable through options, including equal payment plans and deferral accounts which FEI currently uses. AMPC/CEC notes than in addition to these options, FEI is proactive in communicating the natural gas cost advantage relative to other sources.

AMPC/CEC also submit that a telling point with regard to competitiveness is how it compares to electricity. They assert that FBCU's response to AMPC/CEC 1.4.2 (Exhibit B1-15) outlines the savings of natural gas over electricity for space heating (and to a lesser extent water heating) and demonstrates a trend that continues to widen. In their view, this information demonstrates that FEI is the beneficiary of both a reduction in gas prices and rising BC Hydro rates. (AMPC/CEC Final Submission, pp. 11-16)

In Reply, FBCU argue that using November 2009 rather than July 2009 is a more appropriate point of comparison and represents a variance of less than 3 percent. They also point out that this difference has been insufficient to drive behavioral changes in new and existing customers. (FBCU Reply, p. 14)

Figure 3: Delivered Cost of Natural Gas

Figure 34. FEI Lower Mainland Annual Residential Bill History (Rate Schedule 1)



(Source: Revised Exhibit B1-9-6, Appendix H, p. 51, Figure 34)

Additionally, FBCU state that they have not suggested that there is an increase in price volatility, but rather they have fewer tools to deal with it. Overall, FBCU submit that commodity price volatility is a risk factor which remains undiminished since 2009. (FBCU Reply, pp. 14-15)

Commission Determination

The Commission Panel considers price, because of the importance placed on it by the consumer, to be a key determinant and deserves significant weight when considering changes to FEI's risk. **The Commission Panel finds that there has been some reduction in the level of risk associated with the competitive position of natural gas as compared to electricity.** It is difficult to reach any other conclusion given there has been a reduction in the total billing costs while over the same period the cost of electricity has risen regardless of the timeline one chooses for comparison. The evidence relied upon by the interveners in Figure 1, which details the growing variance between natural gas and electricity, is persuasive and it is unlikely that a price conscious customer would move away from natural gas in these circumstances. Looking ahead, and relying upon the information in Figure 2 above, the Panel notes that in spite of the range considered to fall under the 95 percent interval band, the September 4, 2012 AECO Forward Curve projects relatively stable natural gas commodity costs looking out to 2017. While hardly definitive, this does point to some level of stability over the next few years.

Notwithstanding these favourable conditions, the Commission Panel does place some weight on the lack of change in the purchasing behaviour of new and existing customers. In our view, some of this relates to the higher capital costs required to convert to or install natural gas service and the move to multi-family dwellings, which is discussed in Section 4.2.4.

FBCU state that price volatility is a risk factor that remains undiminished since 2009. Based on the evidentiary record we agree. However, we are not in agreement with the assertion that FEI have fewer tools to manage volatility. In the PRMP Decision, the Commission Panel offered a number of suggestions or options FEI may wish to consider. Included among these was offering the PRMP program to existing customers on a permission basis. There is no evidence before the Panel to indicate any action that FBCU has taken to bring alternatives forward.

4.2.4 Customer Growth

Submissions by Parties

FBCU note that a continuing trend has been its lower capture rate on new construction and reports a decline in the rate of net residential customer additions when 2011 is compared against 2007. In addition, the FBCU submits that new customer usage is roughly half what it used to be and therefore, the trend that existed in 2009 has not changed. FBCU states that this trend is closely associated with growth of multi-family dwellings in BC, a market where FEI has low penetration driven by unfavourable installation economics. This shift toward multi-family dwellings means that FEI's capture rate will further decline over time. (FBCU Final Submission, pp. 50-51; Exhibit B1-9, Appendix H, pp. 33-37)

AMPC/CEC point out that in spite of the challenges faced by FEI in growing customers, its total customer base continues to grow. The number of residential customers grew by 8 percent over the period 2005-2011 and the number of commercial customers grew by 5 percent over the same period while there was some decline in the number if not the consumption of industrial customers. (AMPC/CEC Final Submission, pp. 16; Exhibit B1-11, BCUC 1.4.4)

Commission Determination

The Commission Panel notes that the circumstances related to unfavourable installation economics and the shift toward multi-family dwellings existed at the time of the 2009 Decision. In spite of this, the total number of customers continues to grow if not the market share of potential new customers. **Therefore, the Commission Panel finds that there is no persuasive evidence to suggest there has been a shift in risk related to customer growth.**

4.2.5 Impact of Alternate Energy Services on FEI

Submissions by Parties

FBCU state that the "adoption of energy forms produced in combination with newer technologies represents a challenge to FEI's core business for providing natural gas for space and water heating." The recent number of energy projects approved serves to demonstrate the momentum behind alternative energy which FBCU rate in the number 2 risk category. In FBCU's view, the growing consumer awareness of alternative energy and its green attributes and increasing cost effectiveness demonstrate the importance of this risk factor for FEI. (FBCU Final Submission, p. 52; Exhibit B1-9, Appendix H, p. 28)

AMPC/CEC argue that this represents double counting and there is no evidence to suggest that there is more risk posed by alternative energy to FEI than that which existed in 2009. Further, they argue that the new transportation technology will result in improved prospects as it allows natural gas to replace diesel in heavy trucking thereby increasing natural gas demand in the future. (AMPC/CEC Final Submission, p. 18)

Commission Determination

The Commission Panel notes that the impact of AES sources on FEI is not a new risk. However, we do acknowledge that in the three years since the 2009 proceeding, there has been greater momentum behind alternative energy forms and the adoption of new technology related to them. Therefore, the Panel is mindful that there is the potential for an increase in risk related to AES but, given that much of this risk has been accounted for in reference to FBCU's share of multi-family dwellings, it is difficult to quantify.

4.2.6 Market Demand and Throughput

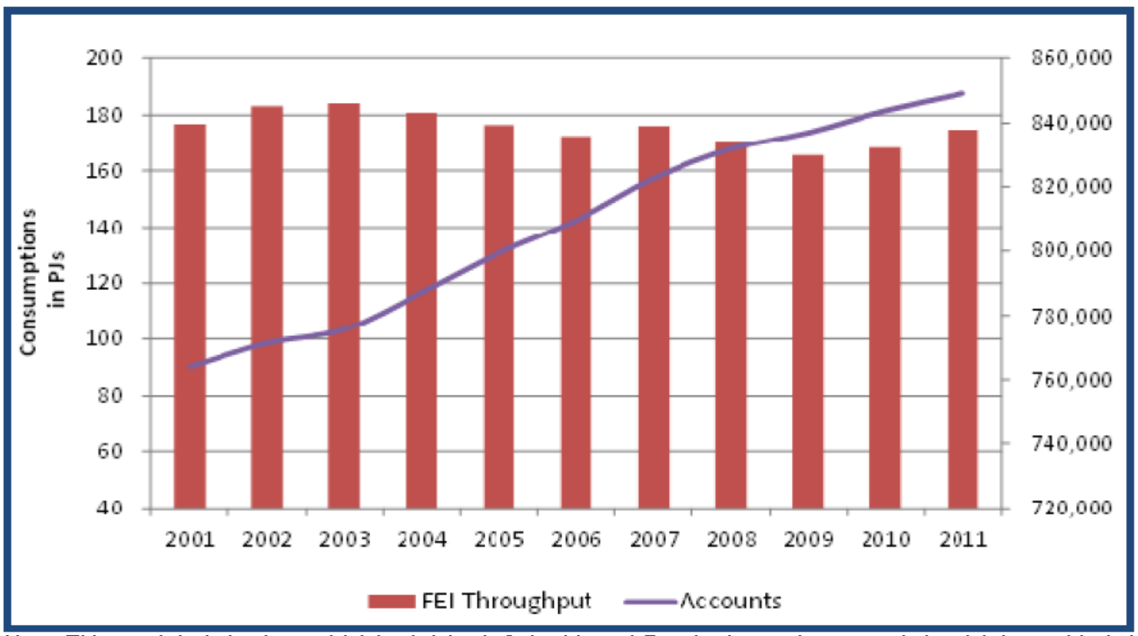
Submissions by Parties

The FBCU state that FEI's use per customer (UPC) for both new and existing customers has been declining; this trend, based on a Conservation Potential Review Study, is expected to continue until 2030. Contributing to this decline are a variety of factors including technological advances and energy efficiency improvements. In addition, the decline in UPC can, in part, be attributed to increased efficiency standards, better building envelopes and a move to smaller dwellings. Further, FBCU state that new construction research since the 2009 hearing shows that natural gas has been increasingly used as a secondary fuel source in new homes rather than the primary source. The FBCU state that there is no reason to believe the drivers behind these market trends will cease. (FBCU Final Submission, pp. 52-53; Exhibit B1-9-6, Appendix H, FBCU Evidence, pp. 32-35)

ICG states that Exhibit B1-41 shows that there has been no decline in system throughput since 2009. In addition, ICG asserts that there is an upward trend in industrial throughput, which is reflective of lower natural gas prices over the same period. Given this recent trend, ICG argues that the Commission should not accept the FBCU's 2013-2016 lower industrial throughput evidence and conclude that business risks are in fact lower than in 2009. (Exhibit B1-41, Undertaking No. 6, p. 3; ICG Final Submission, pp. 7-9)

BCPSO notes that the Commission acknowledged the risks related to throughput in its 2009 Decision and, as a result, they are not new. BCPSO, like AMPC/CEC, further submit that based on graphical information in Figure 4 below, the trend of declining throughput has reversed itself in 2009 and has increased each year since. (BCPSO Final Submission, pp. 13-14)

Figure 4: FEI's Total Throughput (Normalized Demand vs. Customer Accounts)



Note: This graph includes Lower Mainland, Inland, Columbia and Revelstoke service areas. Industrial demand includes both sales and transportation volumes.

(Source: Exhibit B1-9-6, Section H, p. 9)

AMPC/CEC submit that the evidence presented by FBCU shows that both commercial and industrial UPC has increased since 2009, while residential UPC has decreased only marginally.

AMPC/CEC further submit that as the Commission considers the issue of declining UPC, it should consider two points:

- The residential throughput would have to decrease by 83 percent in 2012 to drive its distribution margin to a level equal to BC Hydro Tier 2 Rates; and
- The negative trend related to the creation of energy efficiency is no different than that faced by BC Hydro.

AMPC/CEC argues that these energy trends are not new and there is only risk if they affect the utility's ability to earn a fair return which, in their view, is not supported by the evidence on the record. (AMPC/CEC Final Submission, pp. 16-18)

In Reply, FBCU submit that revenues related to increased throughput are largely unaffected due to the structure of industrial contracts that only generate additional revenue if consumption exceeds an agreed upon level. Therefore, the declines in residential and commercial UPC continue to have a disproportionate impact on FEI. FBCU also point out that AMPC/CEC's reliance on Tier 2 rates is inappropriate. In addition, they argue that the AMPC/CEC's position is based on the view that existing customers will not leave natural gas until there is no longer a price advantage. FBCU state that this assumption is unwarranted given recent research that people are less committed to natural gas, irrespective of price. (FBCU Reply, pp. 16-17)

Commission Determination

The Commission Panel finds that there is insufficient evidence to support a finding that there has been a shift in risk related to market demand and throughput.

The Commission Panel notes that the decline in UPC and overall throughput were issues raised in the 2009 proceeding. Based on the evidence in this proceeding, it is apparent that the overall throughput has increased since 2009 and UPC, while decreasing overall, has increased for both commercial and industrial customers. In the view of the Panel, these are all positive but not conclusive signs.

The Commission Panel places little weight on the FBCU submission that the increased throughput has not resulted in increased revenue due to the structure of industrial contracts. Notwithstanding our understanding that industrial contracts are subject to competitive negotiations, in our view, FBCU nonetheless has some control over the structure of and risks related to the contracts it negotiates.

The Commission Panel does not consider the research indicating existing customers are less committed to natural gas in spite of the price advantage to be persuasive. The Panel notes that much of the research referred to in this context was related to AES options, which have been considered as part of the growth of multi-family dwellings addressed in Section 4.2.4.
(Exhibit B1-9-6, Appendix H, FBCU Evidence, pp. 32-35)

4.2.7 Supply Risk

Submissions by Parties

FBCU's position is that BC's shale deposits do not guarantee a reliable supply of natural gas at reasonable prices. Due to the higher cost of development relative to other areas and a lack of infrastructure for resource development and market connection, FBCU state that growth of production in northeastern BC has stopped and there is risk of current levels declining. This is in contrast to developments like the Marcellus Formation in the northeast part of the continent that is thriving. FBCU submit that this leads to the possibility of stranded resources or, at a minimum, higher market prices and an expansion of access infrastructure to encourage expansion of BC's shale gas resources.

FBCU also submit there is a lack of new development of infrastructure to move gas to FEI's service territory. They argue that the development of gas transmission infrastructure projects connecting BC sources with Alberta and Eastern markets, combined with the potential for LNG exports, could change the historical pricing relationship between BC supply and Alberta production leading to higher consumer prices in the future. (FBCU Final Submission, pp. 60-61)

AMPC/CEC describe the potential for stranded resources in northwestern BC as nonsensical. They submit that the impact of shale gas development on prices was not recognized, as it was not mentioned in the 2009 Decision. They also refer to the following statement of Ms. Des Brisay in the current proceeding:

> "What was not fully understood is how low the cost could be in terms of how we produced that resource, and that's really where we have seen the shifting of the curve has been as we have a better understanding of the economic feasibility of the development of shale gas reserves in different parts of North America."
> (T2:161)

Therefore, AMPC/CEC argues the existence of reserves may have been known in 2009, but the understanding of the economic feasibility of development has shifted since then. (AMPC/CEC Final Submission, p. 19)

AMPC/CEC submit that any weight the security of supply factor deserves pales when compared to the availability of supply. The Commission Panel notes they did not comment directly on the potential change to the historic pricing relationship between Alberta and BC. (AMPC/CEC Final Submission, pp. 18-20)

As noted previously, FBCU acknowledge that shale gas has been a "game changer" and that supply risk has declined. They did make the following points:

- There was knowledge of natural gas reserves prior to the 2009 proceeding.
- The price of natural gas must be higher (leading to higher rates) before supply will be extracted.
- FEI's ability to access cost effective supply could be challenged as there are competing markets for natural gas.

FBCU argue that it is the factors affecting demand for delivered natural gas, not energy supply considerations, that are the key supply risk for FEI. (FBCU Reply, pp. 19-20)

Commission Determination

The Commission Panel finds that there has been a decrease in the risk associated with the supply of gas but an increase in the risk associated with access to this gas at low prices. Balancing the two, there has been no material change in the level of risk related to energy supply.

The Commission Panel accepts the statement of Ms. Des Brisay as informative and a reasonably accurate reflection of where matters stood at the time leading up to the 2009 Decision. There is clearly no disagreement among the parties with respect to the existence of adequate supply of natural gas and FBCU have conceded that the actual supply risk has declined. Therefore, the issue is not whether natural gas will be available but whether sufficient natural gas will be available at the low commodity price levels that the consumer has come to expect. To this end, FBCU have laid out a number of facts and potential scenarios which they argue will have a significant impact on the supply of low cost natural gas. None of the interveners have challenged this information except AMPC/CEC who characterized the potential stranding of assets as "ludicrous."

In our view, the potential for some of FBCU's concerns to become a reality cannot be dismissed. The stability of the current environment remains uncertain, as does the magnitude of future development of the LNG business. Until this has been determined, the continuity of current low price levels for natural gas will be at some risk. However, the risk of supply to the extent that it existed, has abated and shifted to the risk associated with maintaining existing commodity price levels with no resulting increase in overall risk.

4.2.8 Regulatory Risk

Submissions by Parties

FBCU has ranked regulatory risk as their highest risk area with a number of factors in the "higher risk" category. In assigning this weighting, FBCU states that FEI is dependent on regulatory approvals that determine its revenue requirements, cost of service recovery and approval of investments. FBCU submit that the pace of change in the energy policy and environment has increased at a time when the Commission's role in implementing and applying policy has expanded. This has contributed to increased uncertainty in the regulatory environment and added process as compared to 2009. (Exhibit B1-9-1, Section H, pp. 5-6)

BCPSO points out the FBCU witnesses have confirmed that the regulatory environment is predictable and stable and regulatory risk should not be viewed as its number one risk factor. (BCPSO Final Submission, pp. 14-15)

AMPC/CEC questions the FBCU ranking of regulatory risk as there is no compelling evidence to suggest that FEI faces greater regulatory uncertainty than it did in 2009. (AMPC/CEC Final Submission, pp. 10, 20)

In Reply, FBCU acknowledge that the relative stability and predictability of the BC regulatory framework reduces regulatory risk. However, they point out that the breadth of the Commission's influence on FEI's business is undeniable and individual decisions can have significant implications for FEI particularly in the short-term. While they identify "regulatory risk as being 'higher,' any change since 2009 was not material to FEI's overall risk." (FBCU Reply, p. 12)

Commission Determination

The Commission Panel finds that there has been no material change in the level of risk associated with regulatory risk.

The Commission Panel accepts that the BC regulatory framework has a significant influence on FEI's business and that individual decisions can have significant implications for FEI. However, we agree with the parties that argue there has not been a material change since the 2009 Decision.

4.3 FEI's Short-Term Risk

There are two issues that must be considered by the Commission Panel with respect to short-term risk. The first is whether there has been a change in short-term risk since the 2009 Decision. The second is how much of FEI's short-term risk has been mitigated and, as a result, how much of the remaining risk must be considered. In the view of the Commission Panel, this will be determinative as to the level of weight to be placed upon the short-term risk in this proceeding. FBCU has expressed disagreement with the need to determine the level of short-term risk in reply to BCSPO submissions:

> "The Commission need not attempt to characterize or quantify FEI's short-term risk to determine a fair return for FEI. The question requiring a determination is the extent to which FEI's short-term risk has changed since 2009." (FBCU Reply, p. 9)

The Commission Panel disagrees. There are many measures of risk. The overall level of risk may not have changed substantially but one needs to consider the individual risk elements and their weighting. These may have changed and therefore, not considering them may be a mistake.

4.3.1 <u>Change in Short-Term Risk</u>

Submissions by Parties

The FBCU submit that short-term risk is essentially the same as in 2009. (FBCU Final Submission, p. 45)

Both FBCU and the interveners have focused their submissions on two areas in examining short-term risk:

- FEI's record of generally being able to earn its allowed ROE; and
- The amount of risk mitigation provided by deferral accounts.

Matters related to FEI's history of typically earning its ROE were dealt with in Section 3.3, where it was determined that actual earnings versus approved earnings history is more appropriately a matter for consideration in revenue requirements proceedings.

Concerning the use of deferral accounts, FBCU submit that "FEI's ability to manage short-term risk with deferral accounts is a function of the portion of the overall revenue requirement covered by deferrals, irrespective of the number of accounts providing that coverage." They also submit that there has been no material change in the collective scope of deferrals having an effect on earnings volatility. In the view of FBCU, their evidence on deferral accounts shows that the percentage of revenue requirements covered by deferral accounts has decreased and has resulted in a credit to customers. (FBCU Final Submission, pp. 38-45)

AMPC/CEC acknowledge that some of the additions in deferral accounts since 2009 are a reflection of accounting changes, but submit that three new accounts (Compliance to Emission Regulation Account, Customer Service Variance Account and Depreciation Variance Account) are significant. They further submit that while the new accounts may not represent a monumental change, they are an indication of FEI's ability to obtain such accounts. Therefore, this risk factor is lower today than in 2009. (AMPC/CEC Final Submission, p. 22)

BCPSO agrees with the submissions of AMPC/CEC and submits that the addition of the three new accounts demonstrates the Commission's willingness to mitigate the impact of short-term uncertainties. It concludes that the new accounts indicate short-term risk is no greater and likely less. In sum, BCPSO submit that short-term business risk is lower than in 2009. (BCPSO Final Submission, pp. 8-9)

FBCU, in reply, assert that the submissions of AMPC/CEC are at odds with the evidence of their witness, Dr. Booth, "who admitted that FEI risk hadn't changed "in the slightest."" The Commission Panel notes that Dr. Booth (T8:1475) was referring to ROE and not overall risk. FBCU conclude that short-term risk when compared to risk faced by its peers in other jurisdictions, remains unchanged. (FBCU Reply, p. 9)

Commission Determination

The Commission Panel, after reviewing the evidence, finds that there has not been a material change to FEI's short-term risk since the 2009 Decision. However, to the extent that there have been additional deferral accounts added, there is a greater ability to mitigate short-term risk. The Commission Panel agrees with BCPSO that the Commission's approval of the new deferral accounts demonstrates a willingness on the part of the Commission to mitigate the impact of uncertainty. However, in the Panel's view it is not important how the deferral account came to be. It is the effect. Therefore, the fact that the Depreciation Variance Account was ordered by the Commission, as noted by FBCU, in our view, is immaterial. More important is the fact that the deferral account now exists, as it reduces the risk associated with unforeseen variances in depreciation amounts.

4.3.2 Magnitude of Short-Term Risk

The second question to be considered by the Commission Panel with respect to short-term risk relates to the level of mitigation which has or could be applied against short-term risk. Much of the evidence related to this was focused on the use of deferral accounts which we explore below.

Revenue Related Deferral Accounts

The FBCU consider the overall risk for residential and commercial sales to be moderate and have assessed the risk of industrial sales to be high.

In 2011, residential and commercial sales accounted for 87.9 percent or $485.4 million of the total delivery margin revenue of $552.3 million. FBCU are protected for changes in use per customer for residential and commercial sales through the Rate Stabilization Adjustment Mechanism (RSAM). In assessing these risks as moderate, FBCU point out they are not protected for any differences in actual and forecast number of new customers in a given test period. The Commission Panel notes that impact of any variance in customer additions is likely to be minor, given the relatively small number of new customer additions as a function of the existing customer base. **Given the relatively heavy reliance on existing customers for most of the revenue and the existence of the RSAM, the Commission Panel finds the short-term risk related to residential and commercial sales to be low rather than moderate as suggested by FBCU.**

Industrial sales account for 12.1 percent or $66.8 million of the delivery margin revenue in 2011. FBCU assess the risk as high in this area because there are no deferral accounts utilized with this customer group. (Exhibit B1-20, BCUC 1.96.1)

In reviewing the submissions, the Commission Panel notes the following statement made by FBCU in reply to AMPC/CEC submissions: "Increased consumption by industrial customers only generates additional revenue if the consumption **exceeds a customer's fixed contract demand** (i.e., the 'take or pay' volume)." [emphasis added] Notwithstanding the impact on revenue as addressed in this statement, it appears to the Panel that the lack of deferral accounts in the industrial category is because there is no need as this area is run on a contract basis with a reliance on "take or pay" contracts. (FBCU Reply, p. 16) It is therefore evident that potential risk is mitigated to a large extend by the existence of such contracts. **For these reasons, the Commission Panel finds that a "high" risk rating for industrial sales is inappropriate and a moderate to low rating is more appropriate to the level of risk.**

Expense Related Deferral Accounts

Table 1 of the FBCU response to BCUC IR 1.96.1.1 indicates that in 2011, 75.3 percent ($1,160.7 million) of the FEI revenue requirement or 31.0 percent ($171.1 million) of the Revenue Margin Delivery Requirement was covered by way of deferral accounts. Overall, the single biggest expense item was cost of gas, which at $989.6 million is 100 percent covered by deferral mechanisms.

FBCU's Operation and Maintenance (O&M) Expense totalled $184.6 million. Of this, approximately 9 percent encompassing Pension & OPEB Variance, Insurance Variance and BCUC Levies Variance Deferral is covered by deferral accounts. FBCU rates the overall risk of O&M Expense as high citing the small portion covered by deferral accounts in explanation.

The Commission Panel also notes that of the remaining revenue requirements categories, Property and Sundry Taxes ($50.2 million), Financing Costs ($108.5 million) and Depreciation and Amortization ($99.9 million) are at or near 100 percent deferral account protection levels. (Exhibit B1-24, BCUC 2.182.1; Exhibit B1-20, BCUC 1.96.1)

The most significant area not covered to a large degree by deferral accounts is O&M Expenses. O&M Expenses are also an area where there is a history of under spending approved O&M amounts. Under cross-examination, Mr. Dall'Antonia explained that risks at the start of each test year are the same and the success of managing within budgets can be attributed to management's experience and being sound managers. (T3:344) While the Commission Panel does not take issue with Mr. Dall'Antonia's comments, we are of the view that in addition to this, FEI has a broad range of options available to it to manage O&M budgets effectively. For example, many of the initiatives in an approved O&M plan can be postponed for short periods or in some cases not implemented within the test period. This could include items such as routine maintenance, new staff additions, replacement of staff vacancies or delaying of new programs or initiatives. This may, in part, account for the fact that O&M expenditures were less than forecast in 8 of the last 9 years. (Exhibit B1-24, BCUC 2.182.1) Therefore, in the view of the Commission Panel, this is an area where FEI has a high degree of control. **Accordingly, the Commission Panel finds that a high risk rating for O&M expenses is not appropriate and a moderate to low rating is more reflective of the risk FEI faces.**

Another area with a high risk rating due to limited use of deferral accounts is Other Operating Revenue which encompasses things like late payment charges, NSF cheques, and connection charges. This item has been in the $20 to $25 million range over the last nine years, which is a relatively small part of revenue requirements. However, as outlined in Undertaking No. 8, there have been consistent negative variances (meaning revenues were less than approved) in the $2 million range for all but the most recent completed year. (Exhibit B1-24, BCUC 182.1; Exhibit B1-20, BCUC 1.96.1; T2:293-294; Exhibit B1-43)

The Commission Panel acknowledges that many of the Other Operating Revenue areas are less predictable and controllable in nature and most items are not covered by deferral accounts. Therefore, the Commission Panel finds that a high risk rating is appropriate.

Commission Determination

Given our findings with respect to revenue risks and risks in expense areas not covered by deferral accounts, the Commission Panel is not persuaded that on balance FEI faces significant short-term risks to its achieving its allowed ROE in a given test period. While including items that are less predictable or controllable, the Other Operating Revenue item generally shows a consistent pattern of under earning revenues. However, their impact on the total revenue requirements is relatively small. **Therefore, acknowledging that there has been little change in short-term risk since the 2009 Decision, the Commission Panel has determined that only minimal weight can be given short-term risk as an impediment to earning a fair return.**

4.4 Developing an Optimal Capital Structure

An important component of the Panel's task is to determine an allowed capital structure. This section is devoted to the discussion of the evidence presented that relates to the capital structure decision and presents the Commission Panel's findings. In this section, we set out the context within which this evidence has been considered.

4.4.1 Capital Structure and the Fair Return Standard

Background on the role of capital structure on the cost of capital is provided in the Brattle Report, which recognizes that "underlying asset risk in each company is typically divided between debt and equity holders – making them derivatives of the underlying asset return." In addition, the result of a specific capital structure is a particular Weighted Average Cost of Capital.

$$WACC = r_d(1 - T_C).\frac{D}{V} + r_E\frac{E}{V}$$

where: r_d = market cost of debt; r_E = market cost of equity; T_C = corporate income tax rate; D = market value of debt; E= market value of equity; and V = the market value of the firm (i.e., V= D+E).

(Exhibit A2-3, pp. 38-40)

This cost of capital reflects the equity risk and the debt risk, both of which in turn reflect both operating and financial risk, as well as the tax advantage of debt.

The integration of the capital structure decision with the ROE decision is recognized in the argument of AMPC/CEC:

> "Capital structure is important for two main reasons: (1) the cost of equity is higher to reflect the greater risk of investing in shares as opposed to bonds, and (2) the cost of debt (interest) is tax deductible, whereas the cost of equity (dividends) is paid out of after-tax income. Consequently, equity is substantially more expensive than debt. . . . FEI's customers have a right to expect that its capital structure will be efficient and the common equity component will reflect the real risks equity shareholders are exposed to." (AMPC/CEC Final Submission, p. 32)

Ms. McShane submits that the inter-dependence between capital structure and ROE is largely based on the FRS with its three requirements i) the ability to attract capital on reasonable terms, ii) maintenance of financial integrity; and iii) comparability of returns. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 34)

These considerations translate into a focus on credit metrics and the need to maintain a particular credit rating. The FBCU does, however, discuss at length the possible disruptions that might take place if FBCU experienced a rating downgrade. AMPC/CEC submit that FBCU's credit metrics are not weak and that a 35 percent common equity ratio (as compared to its existing 40 percent ratio) "is entirely consistent with the objective of maintaining FEI's existing credit rating." (Exhibit B1-9-6, McShane Evidence, Appendix F, pp. 35-37; FBCU Final Submission, pp. 12-15; AMPC/CEC Submission, pp. 32, 34-36)

4.4.2 Commission Panel Discussion

The Commission Panel accepts the view put forth by AMPC/CEC that the capital structure should be set efficiently. The Panel also notes that debt comes with advantages, primarily the deductibility of interest payments from taxes.

At the same time, the Commission Panel recognizes the argument made by FBCU that the excessive use of debt could disrupt the operations of the company by making it difficult to finance the ongoing operations.

The Commission Panel accepts, therefore, that there are both expected benefits and expected costs associated with the use of debt. The task faced by the Panel is to determine the 'optimal' capital structure, one that is efficient in reducing the total or WACC through the use of debt without creating potential financing disruptions that could offset these benefits to the point where the net benefit is reduced.

The discussion of the capital structure evidence and determination found in this section reflects the Panel's desire to find an efficient or optimal capital structure. In doing so it applies the following principles to guide its analysis:

1. While credit ratings are important indicators of the risk of disruption, a particular rating is not in and of itself the definition of an efficient capital structure. Possible ratings downgrades are important but must be considered in terms of the attendant costs and benefits.
2. The long-run risks discussed by all parties are important considerations in determining an optimal capital structure. They indicate operating uncertainties that can cause financial distress and the possible attendant disruption and distraction of management. Since the concern is with financial disruption, both diversifiable and non-diversifiable risks must be recognized in assessing the risk of financial disruption.
3. The stand-alone principle implies that the risk of disruption due to financial distress is assessed within the context of the risks to the benchmark utility. It is in this sense that the Panel agrees with FBCU's view that FEI is not a diversified investor. (FBCU Final Submission, pp. 130-131) As discussed in Section 5, however, this does not imply that the Panel accepts this view with regard to the ROE.

4.5 Credit Ratings and Metrics

An important issue for the Commission Panel is to determine how important it is for FEI, as the benchmark utility, to maintain an "A" category credit rating among credit agencies. Credit ratings are important indicators of potential financial disruption as discussed in Section 4.4. A lowering of credit agency ratings raises concerns about the cost of debt and access to the credit market at reasonable cost. Therefore, there are clearly advantages of maintaining an ROE and capital structure which will allow for existing credit agency ratings to be maintained. However, the Commission Panel must consider whether there is a point where maintenance of a particular credit rating may result in a capital structure or ROE that is suboptimal in the circumstances. In such instances, what importance should the Commission Panel place on the maintenance of a credit rating and at what additional cost?

Presently, FEI is rated by Moody's and DBRS, with Moody's providing the lower credit rating at A3, which is just one level above a Baa rating. DBRS provides a slightly higher A rating, which is comparable to a Moody's A2 rating. (Exhibit B1-58) The Moody's rating is considered to be more vulnerable to a downgrade due to weaker credit metrics, which, with further deterioration and a less predictable and supportive regulatory environment, could result in a drop to the Baa rating. (Exhibit B1-9-6, Appendix F, Ms. McShane Evidence, p. 59) This Baa rating could reduce the financial integrity of FEI by reducing its ability to maintain credit and access capital on as reasonable terms as an A3 rating.

The Commission determined in the 2009 Decision that Moody's rating should be the focus of attention because it was the lower in the group, and that the Moody's A3 rating should be maintained with a margin of cushion to ensure the financial integrity of FEI. (2009 Decision, p. 15)

None of the interveners took the position that FEI's 'A' rating should be jeopardized. AMPC/CEC submit that a reduction of the ROE to 7.5 percent at the existing 40 percent equity ratio would still leave FEI with strong credit metrics, including a cash flow coverage ratio of 2.67, and that a combined ROE reduction to 7.5 percent and lower equity ratio to 35 percent would leave FEI with a 2.35 ratio, which would still be above Moody's stated threshold of 2.3 to maintain the A3 rating. (AMPC/CEC Final Submission, pp. 35-36)

FBCU state that their current credit metrics are already weak for the existing rating and that the combined reduction in ROE and equity ratio as suggested by AMPC/CEC would not allow it to have a margin of comfort. (FBCU Final Submission, p. 15) FBCU also state that Moody's assessment of regulatory support had already weakened because of BC provincial energy policy. (T3:366) FBCU further state that under the Trust Indenture, Dr. Booth's recommendation would result in a coverage ratio of approximately 1.97. (FBCU Final Submission, p. 77)

Ms. McShane noted that the importance of 'A' category credit ratings arises from two factors: market access and cost. With respect to market access, Ms. McShane testified that regulated issuers can at times be closed out of the market if they have less than an 'A' category rating. Ms McShane further testified that "during the period June 2008 to January 2009, there was not a single issuer without at least one "A" credit rating who was able to issue long term debt <u>on any terms</u> in the Canadian market." With respect to cost, Ms. McShane states that in addition to market access issues, a rating downgrade would result in a cost increase to additional debt the company needs to raise. Further, it will also affect all of the utilities' outstanding debt as the increased cost of new debt will increase the required yield on existing debt and reduce the value of that debt. This higher cost of debt to the utility results in a higher cost of debt for ratepayers.
Ms. McShane further submits that institutional investors continue to have limits upon the amount of 'sub A' category debt they are able to hold or are restricted from holding Baa/BBB debt at all. This underscores the importance of 'A' credit ratings given the relatively small size of the Canadian market for Baa/BBB debt. (Exhibit B1-9-6, Appendix F, Ms. McShane Evidence, p. 35-37)

Mr. Engen submits that the 10 year bond yield spread for BBB/A rated utilities has been volatile and as of July 6, 2012, is at 38 basis points (bps). This is less than the 100 bps common during the 2008 financial crisis. According to Ms. McShane, over the past 15 years, the average spread between typical A and BBB rated utilities has been 75 bps. (Exhibit B1-9-6, Engen Evidence, Appendix E, p. 34; Exhibit B1-9-6, Appendix F, Ms. McShane Evidence, p. 36)

Commission Determination

The Commission Panel accepts that continued access to debt capital at an attractive price is an important element which benefits the shareholder and may benefit the customer. Based on the evidence of Ms. McShane and Mr. Engen, a drop to the equivalent of a BBB rating by both rating agencies would result in a borrowing rate difference which would be significant. That being said, the Panel is mindful that credit agencies like Moody's rely upon the embedded cost of debt rather than the marginal cost of debt when calculating a utility's credit metrics as argued by AMPC/CEC. (FBCU Reply, p. 22) Based on the testimony of Ms. McShane the approved cost of debt for 2013 (at 40 percent equity) is 6.8 percent. The Panel notes that current marginal rates are substantially below this level. Therefore, we conclude that the embedded cost of debt is likely to be reduced over time, even in the event of a credit downgrade.

The Commission Panel will continue to be guided by the Fair Return Standard with its three tests of financial integrity, capital attraction and comparable return in determining an appropriate capital structure and ROE. The Panel supports the maintenance of an "A" category credit rating but only to the extent that it can be maintained without going beyond what is required by the Fair Return Standard.

The Commission Panel finds that there is sufficient evidence to conclude that the maintenance of an "A" category credit rating is desirable, but not at all costs.

4.6 Other Jurisdictions

There is general agreement among the parties that the major natural gas utilities in Canada should serve as comparables for FEI for the purposes of assessing FEI's capital structure. This group which includes ATCO Gas, Union Gas, Enbridge Gas Distribution and Gaz Metro was used extensively throughout the proceeding as comparators. Dr. Booth also identified Nova Scotia Power Inc. as a reasonable comparator, being a province-wide integrated electric utility.

The equity thickness ratios of the comparator group of utilities are listed below in Figure 5. The equity ratios of the Canadian comparator group range from 36 percent to 39 percent in contrast to Dr. Booth's recommended equity ratio of 35 percent and FEI's current equity ratio of 40 percent:

Figure 5: Canadian Comparative Utility Equity Ratios

Company	Equity Ratio (%)
FEI	40.00
Dr. Booth on FEI	35.00
ATCO	39.00
Union Gas	36.00
Enbridge Gas Distribution	36.00
Gaz Métro *(*Quebec)*	38.50

(Source: FBCU Final Submission, p. 78)

While there is common agreement as to comparable gas utilities, there is considerable disagreement among the parties as to what these comparables suggest about FEI's required common equity ratio. (FBCU Final Submission, p. 78)

4.6.1 FEI Risk Level Relative to Alberta and Ontario Utilities

FBCU submit that the Commission should find that FEI faces higher long-term risk than natural gas distribution utilities in Alberta and Ontario for the following reasons:

- Alberta and Ontario marketplaces are more favourable from the perspective of supply and infrastructure for natural gas, overall marketplace liquidity, the number of storage facilities and pipeline companies that operate in the regions, and overall gas flows;
- Electricity costs in Alberta and Ontario are not heavily influenced by low embedded costs of "heritage hydroelectricity;"
- Eastern based utilities, by virtue of their proximity to the Marcellus Formation, have seen greater benefits from shale gas than FEI;
- The growing prevalence of multi-family dwellings in BC. The FBCU note that in a hearing before the Alberta Utilities Commission in 2011, Dr. Booth described this "condification" as a "significant competitive pressure;" and
- Government policy and legislation is a long-term risk factor for FEI. Among the provinces, BC is at the forefront of GHG reduction initiatives.

  (FBCU Final Submission, pp. 77-81)

FBCU point out that regardless of the analysis relied upon by Dr. Booth, his approach ended up recommending a 35 percent common equity ratio for all Canadian Utilities excepting Gaz Metro. (Exhibit C6-12, AMPC/CEC Evidence, Dr. Booth Evidence, p. 43) In this instance, FBCU had the following concerns with the analysis leading to his recommendation of 35 percent:

- Absent from the comparison was ATCO Gas which was the highest comparator at a 39 percent common equity ratio. FBCU notes that Dr. Booth puts ATCO Gas in the same risk category as FEI and perhaps a little riskier.
- There was no reference to Gaz Metro's deemed preferred shares in his portraying them as having a common equity ratio of 38.5 percent. This effectively understated Gaz Metro's effective deemed common equity ratio.

  (FBCU Final Submission, pp. 77-82)

AMPC/CEC submit that all of the comparators have common equity ratios that are below the current 40 percent common equity ratio of FEI. They also concede that at 38.5 percent, Gaz Metro is at the top of the range. However, they submit that Gaz Metro is in a far more difficult and risky climate than FEI, given FEI's advantage over electricity is 5 times as great as that of Gaz Metro. AMPC/CEC conclude that a common equity that is the same or greater than Gaz Metro's 38.5 percent would be unreasonable on comparative terms. (AMPC/CEC Final Submission, pp. 33-34)

FBCU submit that neither BCSPO nor AMPC/CEC made any attempt to reconcile the inconsistencies in the comparative analysis among Canadian utilities' capital structures. FBCU further submit that Dr. Booth's submission "that ATCO Gas risk was in the same risk bucket or slightly less risky than FEI" is significant because it suggests that the 40 percent common equity ratio for FEI is justified as ATCO has a 39 percent common equity ratio. (FBCU Reply, pp. 24-25)

Commission Determination

The Commission Panel has previously considered this matter in Section 3.2. The Panel has considered the common equity ratio decisions of other Canadian jurisdictions. **However, because each province is different in terms of its levels of regulatory protection and each utility has its own set of unique circumstances which are only minimally covered in the record of this proceeding, the Commission Panel has determined that only limited weight is to be given to the outcomes of proceedings in other Canadian jurisdictions.** Accordingly, evidence related to the equity ratios of other jurisdictions is used as a reference point only in determining whether FEI's is in an appropriate range.

4.7 Capital Structure – Commission Determination

The Commission Panel has determined that a common equity ratio of 38.5 percent is appropriate for FEI effective January 1, 2013.

The Commission Panel has examined the factors contributing to long-term risk in this proceeding and considered the submissions of each of the parties. The Panel has found that reductions are warranted in long-term risk associated with provincial government climate and energy policies as well as the competitive position of natural gas relative to electricity. Both of these risk areas were rated by the FBCU as category 2 risks. To offset these there is not a single area where the Panel has been persuaded the level of long-term risk has been demonstrated to have increased materially since 2009.

The Commission Panel notes that the 2009 Decision put considerable emphasis on the uncertainty created by climate change legislation that did not exist during the previous cost of capital proceeding. In addition, the 2009 Decision acknowledged the change in the competitive position of natural gas versus electricity but concluded that there were too many variables at play for this to be considered permanent. The Panel's finding that there is lower long-term risk related to both of these factors since 2009 is indicative of a reduction in overall risk to FEI which needs to be reflected in the common equity ratio.

Consideration being given to both long and short-term risk, the Commission Panel determines that a reduction in the common equity ratio of 1.5 percent to 38.5 percent is appropriate.

Considering the discussion of optimal capital structure in Section 4.3, the Commission Panel notes that the reduction in common equity ratio to 38.5 percent is reflective of reduced long-term risk and yet balances this against potential disruption caused by a significant weakening of credit metrics.

With respect to credit ratings and metrics, the Commission Panel notes that considerable concern has been raised concerning FEI's credit metrics. In Section 4.4 we found the evidence supportive of maintaining an "A" category credit rating but not at all costs.

The Commission Panel notes that the 38.5 percent equity ratio awarded FBCU in this proceeding falls within the upper end of a range of comparative utilities in other Canadian jurisdictions and considers it to be reasonable on a comparative basis.

FEI is to file within 30 days of this Decision and the accompanying Order G-75-13 a document setting out how and when it will implement the change to its capital structure.

5.0 RETURN ON EQUITY

5.1 Key Issues

The Commission Panel is of the view that an important consideration in this proceeding is the determination of a return that provides investors with the opportunity cost of their investments. The Brattle Report recognizes and elaborates on this fundamental principle:

> "[The cost of capital is] Defined as *the expected rate of return in capital markets on alternative investments of equivalent risk,* it is the expected rate of return investors require based on the risk-return alternatives available in competitive capital markets. Stated differently, the cost of capital is a type of opportunity cost: . . ." (Exhibit A2-3, pp. 2-3)

However, even if one accepts the concept of the opportunity cost as a foundation of a Return on Equity determination, a remaining challenge is that risk and expected return of the relevant 'alternative investments of equivalent risk' are in the eyes of investors who have access to well functioning capital markets. These expectations are not directly observable to Panel members or to parties in this proceeding who provide evidence for the Panel to consider. Instead, estimates of investors' expectations are based on data that are interpreted through *models* of competitive capital markets. The Panel finds an observation offered in the Brattle Report to be instructive:

> "It is useful to recognize explicitly at the outset that models are imperfect. All are simplifications of reality and this is especially true of financial models. Simplification, however, is also what makes them useful. By filtering out various complexities, a model can illuminate the underlying relationships and structures that are otherwise obscured." (Exhibit A2-3, pp. 3, 5-6)

The evidence presented to the Panel was based on a large variety of specific models that fall into four broad classes: (i) DCF models; (ii) CAPM (iii) ERP models and (iv) CE models. Within these four classes are numerous specific implementations that vary in structure, assumptions, and the data from which they were estimated. For instance, there are multiple DCF models with multiple estimates of the appropriate opportunity cost of an equity investment in the Benchmark Utility FEI. The estimates of the investor's opportunity cost of equity, summarized in Appendix F to this Decision, range from 6.15 percent (Dr. Safir CAPM) to 11.50 percent (Dr. Vander Weide's FRP model.

The models and approaches used by the expert witnesses in this proceeding to estimate the ROE are summarized in Tables included in Appendix F of this Decision.

The key issue then in the determination of the appropriate ROE is assessing how much weight to give to each of these models and their estimates. In turn, the weight given to each estimate depends on a judgment of the validity of the conceptual base of the four broad model classes and a judgment of how reasonable the model inputs are. The Panel has based this judgment, as much as possible, on the objective of determining the opportunity cost of equity.

The Panel finds that the two most compelling frameworks for assessing the cost of equity are the DCF model and the CAPM. These models have well understood theoretical bases and explicitly recognize the opportunity cost of capital. Accordingly, these two models are given equal weight in determining the allowed ROE. As discussed in Sections 5.4 and 5.5, the ERP models (with the exception of Ms. McShane's CAPM based equity risk premium) and comparable earnings model are not based on compelling foundations. Furthermore, model inputs and estimates are largely *ad hoc* and assessments of the validity of these inputs and estimates are based on subjective evaluations with minimal logical guidance. Consequently, both the ERP and CE approaches are given no weight in the Panel's determination of the appropriate ROE for the benchmark utility.

5.2 The Capital Asset Pricing Model

The CAPM is based on consideration of individual investors making portfolio decisions in a well functioning capital market. As such, it is a model of the shareholders who own the shares of the firm. Of all the models used to present evidence to the Panel, we consider that the CAPM provides the underpinnings of investor choice in greatest detail.

The CAPM is based on portfolio theory, a theory that answers the question: If an investor wishes to achieve a particular rate of return and is able to invest in a large set of securities, what investment strategy will deliver the target expected return at lowest possible risk? (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 78) The somewhat surprising answer given by portfolio theory is that all investors will hold a combination of two mutual funds; one made up of all risky securities available, referred to as 'the market portfolio' and the second made up of risk free securities. In contrast to intuition, individual risk aversion will not determine which specific securities to invest in but will determine how much of an investor's wealth will go in the market portfolio and how much will go into risk-free securities. A more risk-averse individual will hold less of their wealth in the market portfolio and more in treasury bills than a less risk-averse individual.

The result that investors will hold well diversified portfolios instead of individual stocks provides great guidance in elaborating on the seminal Supreme Court of Canada decision of *Northwestern Utilities* that the allowed return on capital is to be comparable to the return that would be earned on "... the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise." (Exhibit A2-3, p. 2) The CAPM tells us that these 'other securities' are not other comparable firms but are instead comparable portfolios that combine the market and the risk free rate.

The Commission Panel notes that the reason investors are better off holding a mutual fund instead of picking individual stocks is diversification. Diversification builds on another bit of intuition: don't put all your eggs in one basket. As The Brattle Report states:

> "…when security returns are positively correlated (i.e., have a tendency to move in the same direction, to some degree), trade in capital markets allows investors to reduce their total risk exposure by holding portfolios, which serve to diversify the risk of the individual securities. Diversification permits investors to obtain lower variance for a given expected return or a higher expected return for a given level of variance, where variance of returns over time is a measure of risk."
> (Exhibit A2-3, pp. 6-7)

Since diversification is a driving force in investor's decisions, leading them to hold broadly diversified portfolios, when they consider the value of an individual stock they do not consider the total risk of the stock in isolation. They instead consider the amount of risk the stock will add to the risk of the mutual fund, recognizing the effect the stock has on the total diversification achieved. The amount of risk that remains after the benefits of diversification is referred to as non-diversifiable or systematic risk. The measure of the systematic risk is called beta. (Exhibit A2-3, pp. 6-7; Exhibit C4-9, p. 9; Exhibit B1-9-6, Appendix F, p. 88)

The CAPM builds on portfolio theory by providing a risk return relationship that recognizes beta as the risk measure. The theoretical foundation and the formulation of the CAPM is discussed in the evidence of Dr. Safir (Exhibit C4-9, pp. 8-11) and in the Brattle Report, which states:

> "The presence of a market underlies the "opportunity cost" interpretation of cost of capital – by investing in a security A, an investor foregoes (some) investment in an alternative, "comparable risk," investment B obtainable through the market." (Exhibit A2-3, p. 6)

The opportunity cost of an investment is based on the return on a risk free investment, which is the risk free rate. To this is added a 'risk premium'. In turn there are two parts to the risk premium. The first is the extra return that would be earned by holding the market portfolio on its own instead of the risk free security. The expected return on the market is denoted r_m and the risk premium over the risk free return, r_f, is denoted by (r_m - r_f). This is referred to as the 'the market price of risk' or the 'market risk premium'. The second component of the risk adjustment is beta which adjusts the market risk premium to account for the degree to which the individual stock contributes to the market risk; low beta stocks contribute less than average and earn less than the market rate, high beta stocks earn more.

The advantage of the CAPM is that it distils the complex interactions among risk averse investors trading with each other to a simple equation with three parts:

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

where r_e is the opportunity cost of equity.

So, to estimate the investor's opportunity cost requires an estimate of the risk free return, the market risk premium and the beta. In spite of the CAPM's strong theoretical underpinnings, the estimation of these model inputs presents challenges as outlined in the Brattle Report (Exhibit A2-6, pp. 16-25) and in the evidence of Ms. McShane. (Exhibit B1-9-6, Appendix F, pp. 67-70) The challenges include the role to be played by the US data in the analysis.

The Panel recognizes the growing importance of US and indeed global securities in the portfolios of Canadian investors as pointed out in the evidence of Mr. Engen and of Ms. McShane. (Exhibit B1-9-6, Appendix E, pp. 11, 43-50; Appendix F, pp. A-14, A-15) The Panel also recognizes that none of the evidence was based on data related to global portfolios held by investors; for instance, market portfolios were defined as either the Canadian or US market separately and none of the evidence dealt with an integrated global portfolio. Furthermore, currency risk was not considered nor was the magnitude of foreign ownership of FEI. The evidence presented includes CAPM estimates on either US or Canadian data. In light of these concerns with respect to the lack of a complete global perspective and the potential for risk (including currency risk), the Panel concludes that the more appropriate of these two perspectives is that of the Canadian based CAPM. Therefore, the Panel places greater weight on Canadian based CAPM estimates.

The Panel received a great deal of evidence on various estimates of the following three inputs.

(1) The Risk Free Rate, r_f

Evidence submitted to the Panel indicates that, at the time of filing, returns available to Canadian investors on long-term Government of Canada default free bonds were in the 2.6 to 3 percent range. (Exhibit B1-9-6, Appendix F, p. 77; Exhibit C6-12, pp. 53-71) Although this return was available to investors and therefore seems to meet the requirement of an opportunity cost, all of the experts submit that the appropriate opportunity cost is better measured by the *forecasted* yield on a long-term risk free instrument and that in some cases even this estimate should be adjusted.

Estimates of the risk free return available to investors, based on forecasted long-term Government of Canada Bond Yields, range from a low of 2.95 percent estimated by Dr. Vander Weide (Exhibit B1-9-6, Vander Weide Evidence Appendix G, p. 35) to a high of 4.0 percent by Ms. McShane and Dr. Safir. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 77; Exhibit C4-11, BCUC 1.4.1) Dr. Booth submitted that 3.0 percent was the forecasted yield on long-term Government of Canada Bonds but he considers forecast long Canada bond yields of 3.0 percent to be "well below any 'equilibrium' yield since they are only 1% above the forecast inflation rate and mean locking in a negative real yield for a typical taxable investor." (Exhibit C6-12, p. 60) Dr. Booth testified in cross-examination that:

> "…we do have foreign official flows of money coming into Canada because we are a triple A rate country and they are basically buying Canadian government bonds, pushing up prices, pushing down yields, and pushing them down to a value that I do not think reflects the proper trade-off between risk and return by "an ordinary private investor" making these decisions." (T8:1516)

Accordingly, Dr. Booth adds 0.8 percent to the 3 percent to recognize the alternative, and to arrive at his "Base adjusted LTC forecast" of 3.8 percent. (Exhibit C6-12, pp. 84-85, 93; Exhibit C6-15, BCUC 1.30.3)

In summary, the evidence presented seems consistent in stating that the current rates available on risk free government securities is between 2.6 percent and 3 percent. However, the Panel also agrees with the experts that current monetary policy is historically unusual and subsequently results in the possibility of a higher effective risk free rate. **Therefore, the Panel determines that the estimate of 3.8 percent for the risk free rate is reasonable, corresponds to Dr. Booth's estimate, and is within the relatively narrow range of estimates presented by all experts.**

(2) Market Risk Premium (r_m - r_f)

Estimates of the market risk premium range from 5 percent to 6 percent according to Dr. Booth (Exhibit C6-12, Appendix B, p. 16) to a high of 7.5 percent submitted by Ms. McShane. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 98) The basic estimation methodologies used by all experts were similar in that they were based on historical data on market returns and returns on risk free securities. They differ in some important details.

Ms. McShane bases her estimate on the average return on an investment in the market and shows, in Table 10, page 80 of her evidence that the average return on equities in Canada over the 1924-2011 period is 11.4 percent. From this number, Ms. McShane subtracts the *current* forecasted long-term Government of Canada Bond yield of 4 percent to arrive at her 7.5 percent estimate of the risk premium. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 87) The Commission Panel understands that it is typical to base the risk premium on the average historical difference between the return on the market and the risk free rate. It is our understanding that this approach is to deal with, among other things, the fact that historical market returns and historical bond yields reflect historical inflation while current returns reflect current inflationary expectations. This is an especially important consideration in the current environment where inflationary expectations are at a historically low level. (T3:483-485; T5:713-715)

To illustrate our concern with the approach used by Ms. McShane, the Commission Panel notes that there are times in the last 30 years where this approach would have yielded a very small or even negative risk premium. For instance, Schedule 2 of Ms. McShane's evidence reports that the yield on Long-term Canadian Government bonds in 1990 was 10.69 percent. If this was subtracted from the average market return it would have yielded an unreasonably low market premium. (Exhibit B1-9-6, McShane Evidence, Appendix F, Schedule 2, p. 1; T8:716-717)

Ms. McShane was asked if she could provide a single reference to a textbook or Journal article that advocated using her approach. Her response was that she 'probably could not' (T5:717-718). Accordingly, the Panel gives no weight to the risk premium estimate of 7.5 percent provided by Ms. McShane.

Dr. Booth provides evidence that the historical risk premium is between 5 percent and 6 percent. He adjusts this range for 'Operation Twist' to obtain a risk premium estimate of 5.8 percent to 6.8 percent with a midpoint of 6.3 percent. (Exhibit C6-12, p. 93) Operation Twist refers to monetary policy intended to influence returns at various maturities including long maturities.

Dr. Booth provides two tests of the robustness of his estimate. One robustness test is to compare his estimate of the market risk premium with expectations used by FEI in assessing its defined benefit pension liability. Dr. Booth takes the expectation of market return of 7 percent, provided by FEI's consultants, and converts this geometric return to an arithmetic return. From this, Dr. Booth infers that FEI has, for purposes of valuing its pension liability, accepted an expected market return of 9 percent. Based on this he concludes, on page 93 of his evidence, that "[a]s a result, FEI's data seems consistent with a market risk premium of about 6.2%." In their Final Submission, FBCU submit that the Panel should not rely on data used in assessing pension liabilities. FBCU assert that, since actuaries provided the data, they naturally reflect a conservative bias. FBCU cited its witness Ms. McShane, who stated that pension fund managers and actuaries "... have absolutely no incentive to be anything but very conservative because they have a lot on the line. A pension fund needs to be able to assure that it has funds available to pay its retirees." (FBCU Final Submission, p. 151)

The Panel does not accept the assertion that the actuarial expectations are conservatively biased and should be rejected. Actuaries are charged with fairly assessing pension plan liabilities. The Panel finds, therefore, that this robustness test is indeed helpful in assessing the risk premium.

In a second robustness test, Dr. Booth uses the DCF model to estimate an expected return on the entire market. The resulting estimate is 9.3 percent and Dr. Booth notes that this is very close to the expectation held by FEI's own actuaries. (Exhibit C6-12, Booth Evidence, p. 86) This is a forward looking estimate of the market return so that a forward looking risk free investment can be used to compute the risk premium. Since Dr. Booth concludes in his first robustness test that a 9 percent market return implies a 6.2 percent risk premium, his estimates of 9.3 percent for the market suggests a market risk premium of about 6.5 percent.

FBCU argue that the DCF cannot be used to assess the market as a whole. (FBCU Reply, pp. 29-30) The Panel disagrees with this assertion. Although the model is typically illustrated and applied to a single company, the logic of investors setting prices based on expected cash flows applies equally to a mutual fund or portfolio of shares. The Panel, therefore, does not agree that this approach cannot be taken to estimate the expected return on the market. The Panel therefore finds the DCF based estimate of forward-looking market returns to be helpful as a check.

Other estimates of the risk premium were also in the range of 5.96 percent (Dr. Safir's Canadian estimate, Exhibit C4-9, p. 12, Table 1) to 6.6 percent. (Dr. Vander Weide's estimate, Exhibit B1-9-6, Appendix G, p. 38) **Given the preceding discussion, the Commission Panel accepts a market risk premium of 6.4 percent as it is within reasonable forecasts presented.**

(3) Betas

Evidence on the beta estimates is largely based on a standard approach of regressing returns from comparable firms on market returns. Since FEI does not have traded equity, estimates of beta must be based on comparable firms. In the evidence submitted, the set of comparable firms include Canadian firms as well as, in some cases, US-based firms.

Dr. Vander Weide submits a beta estimate of 0.92 based on the historical ratio of the average utility risk premium to the S&P risk premium. (Exhibit B1-9-6, Vander Weide Evidence, Appendix G, p. 42) Aside from the fact that this is a beta estimate for US Utilities (T6:1092), the method differs significantly from the more commonly accepted method(s) of calculating a beta estimate as set out in the Brattle Report (Exhibit A2-3, pp. 15-16), and as calculated by the other witnesses in the proceeding. Accordingly, the Panel places no weight on this beta estimate.

The other beta estimates submitted range from a low of .36 by Dr. Safir for his Canadian CAPM estimate (Exhibit C4-9, pp. 12, 15), to a high of 0.65-0.70 by Ms. McShane. (Exhibit B1-9-6, pp. 97-98) Dr. Booth provides an intermediate estimate of 0.45-0.55. (Exhibit C6-12, Appendix C, p. 14) All estimates begin with a regression of returns of the comparator firm on market returns with the 'raw beta' being the slope coefficient of the regression.

The differences among estimates largely result from adjustments that are made to the raw betas. Empirical evidence indicates that the regression based beta estimates seem to understate the betas of low risk firms and overstate the betas of high risk firms. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 96; Appendix A to Ms. McShane's Evidence, pp. A-21-26; Exhibit B1-9-6, Appendix G, p. 41) Since, by construction, the beta of the market is one, the adjustments are intended to bring the estimated beta's closer to one. To accomplish this, Ms. McShane contends that it is appropriate to adjust utility betas towards the market average of 1.0. (Exhibit B-19-6, McShane Evidence, Appendix F, p. 96) Both Dr. Booth and Dr. Safir, on the other hand, contend that the adjustment should be to the utility average beta that is in the range of 0.5 - 0.6. (Exhibit C6-12, Booth Evidence, p. 71; Exhibit C4-9, Safir Evidence, p. 15)

None of the evidence presented revealed the actual bias in beta estimates; instead the experts assert a particular adjustment. In cross-examination Ms. McShane acknowledges that utility betas may indeed not trend towards one.

Mr. HOBBS: And because regulation protects companies, isn't it also true that you would not expect betas for utilities to ever trend towards 1?

Ms. McSHANE: To trend towards 1. I guess I don't disagree with that. I never said that they would. (T4:549)

Similarly, in cross-examination at T6:1073, Dr. Vander Weide says*:*

DR. VANDER WEIDE: Yes. And I readily recognize that betas for utilities don't adjust toward 1.0.

In their Reply, FBCU argued:

> "Ms. McShane's relative risk adjustment of 0.65-0.70 for a benchmark utility, based partly on adjusted betas, recognizes the past relationship between utility returns, both in Canada and the U.S., and the returns on the equity market as a whole. Over the longer-term, utility investors have achieved risk premiums that have been significantly higher than 45% to 55% of the risk premiums achieved on the equity market portfolio. That experience is consistent with the empirical evidence that lower (higher) beta stocks generally have achieved higher (lower)

returns than the CAPM and beta would have predicted. It is not logical to conclude that, based on that experience, utility investors now only expect to achieve an equity risk premium that is 45% to 55% of the equity market risk premium (or Dr. Safir's lower 36%) simply because utility share price movements have not exhibited a high degree of correlation with price movements in the overall equity market." (FBCU Reply, p. 35)

An adjustment of beta to the market average of one seems inconsistent with the lower risk in the industry, while realized return seems to indicate a beta that exceeds the industry average. The Panel finds that none of the positions fully explain the beta value and therefore accepts an intermediate beta estimate of 0.6 representing the range of reasonable estimates presented.

5.2.1 Adjustments to the CAPM

A number of experts raised concerns about the validity of the simple 'single factor' CAPM. The term single factor refers to the reliance of the prediction of the model on only the market portfolio, the factor implied by the theory. Ms. Ahern introduced in evidence a summary article that shows how other factors such as firm market capitalization (size) and market-to-book ratios can provide added explanatory power to the single factor CAPM. (Exhibit B2-7, Evidence of Ms. Ahern, pp. 13-14; Exhibit B2-7, Attachment PMA-1, Exhibit PMA-9)

The CAPM is by far the most widely studied asset-pricing model and it is not surprising that more is known about its empirical performance than other asset pricing models. This evidence also implies that improved performance can be achieved by including these well-studied extensions of the model. The Panel notes, however, that none of the experts relied on the extensions as found in the literature findings in dealing with the shortcomings of the single factor CAPM. (Ms. McShane, T5:720-722); Dr. Vander Weide, T6:1102-1108; Dr. Safir, T7:1259-1262; Ms. Ahern, T7:1355-1357; Dr. Booth, T8:1658-1663) Instead, the evidence presented by different experts responded to the relatively poor empirical performance of the CAPM in a number of *ad hoc* ways.

Dr. Vander Weide's response to the weak empirical performance of the CAPM is to place no weight on CAPM estimates even though he provides estimates himself. In cross-examination, however, Dr. Vander Weide testified that he did not attempt any standard adjustments to the CAPM that might improve performance. For instance, he did not adjust for the importance of international markets to Canadians, he did not adjust for changes in capital structure and he did not study the ability of a multi factor model to capture returns. (T6:1108-1111) As a result, the Panel does not accept Dr. Vander Weide's response to the relatively poor performance of the CAPM and continues to place weight on the model.

Ms. McShane and Dr. Booth both attempt to improve the performance of the CAPM by adding empirical analysis in order to augment the basic model. Dr. Booth is clearest in his objective when he states: "I regard this sort of adjustment as converting the CAPM into a conditional CAPM where the CAPM holds conditional upon the state of the financial markets." (Exhibit C6-12, p. 81) Dr. Booth testified that an academic literature exists that supports the analysis of a conditional risk premium and his credit spread adjustment is consistent with that literature. (T8:1659) Ms. McShane does not provide the same link to the academic literature and acknowledged, in cross-examination, that her work is along the lines of a multi factor CAPM. (T5:718-720)

The Commission Panel appreciates the efforts of the experts to recognize and deal with the shortcoming of the single factor CAPM. The evidence suggests there are two main thrusts to this effort: i) improving the estimate of the risk premium by conditioning on the current state of the capital markets; and ii) improving estimates of the risk return relationship by adding the factors to the single factor CAPM. Notwithstanding the efforts, the Commission Panel finds that we are not able to assess the validity of the extensions to the single factor CAPM that were presented as there is insufficient evidence involving the use of multi-factor models in this proceeding. The experts expressed reluctance to include other potential extensions to the CAPM that they thought were too complex. This is further addressed in Section 8.

In this regard, the Panel agrees more generally with the specific concern of ICG who argues that in Ms. McShane's CAPM based ERP, she "…makes an adjustment to the market risk premium of approximately 100-150 basis points because in her opinion market risk premium are in fact correlated with the risk free rate." ICG cites Dr. Safir as characterizing the adjustment as arbitrary and not in keeping with the CAPM model. ICG submits that before the Commission Panel accepts this adjustment there must be very strong evidence to support it. In the absence of such strong evidence, the CAPM specifications should not be changed. ICG goes on to say that: "The evidence regarding the correlation (inverse relationship) between the market risk premium and the risk free rate is in fact just that, it is a subjective judgement, with at best, very limited evidence in support of Ms. McShane's proposed departure from the CAPM model." (ICG Final Submission, p. 19)

In support of its argument that there is limited evidence in support of Ms. McShane's adjustment ICG submits that her evidence in support of a relationship between the market risk premium and the risk free rate is presented on a cumulative basis. It argues that when the same data is provided on a non-cumulative basis the US risk premiums do not follow income returns in the manner she suggests (Exhibit B1-53, Undertaking No. 14) and in some instances the data support the opposite conclusion to that observed by Ms. McShane.

Rather than relate the models presented in this hearing to the academic literature, as presented by Ms. Ahern for instance, the extensions seem to be somewhat *ad hoc* leading to the sort of concerns raised by ICG. There is no evidence, therefore that the models present were not the result of a "fishing expedition." That is, the Panel does not know if other adjustments or specifications would produce different results and we cannot assess whether other non-reported specifications should logically be ignored. In the absence of persuasive evidence that these are of value, the Panel is content to consider simple single factor models. At this time the Panel is not persuaded that the specific model extensions that are presented are valid and hence places no weight on them. However, the Panel recommends that in the future improvements in the model can also be brought into evidence, but the evidence should then include both the model extensions as well as a basis on which to judge the validity of the extensions.

5.2.2 CAPM Based Estimate of ROE

Summarizing the discussion above, the Commission Panel has applied the required judgment and accepts the CAPM estimate at 7.64 percent. This reflects a risk free rate of 3.8 percent, a risk premium of 6.4 percent, and a beta of 0.6.

5.3 Discounted Cash Flow Approach

The basis of the DCF approach is the principle that in a competitive market investors who purchase securities are essentially bidding for expected future cash flows that the security entitles them to. Competition implies that investors search for 'good deals', ones that offer the lowest price for a particular cash flow of a particular risk. The higher the price paid, the lower the expected return, so, in an attempt to improve their lot, investors search for securities that trade at a low price generating a high expected return. In their quest for high returns, they are willing to pay a price up to a level that would make the purchase at least as good as the next best alternative, i.e. equal to their opportunity cost. Of course, in a competitive market, other investors are also looking for good deals and, as a result, competition ensures that observed prices generate returns equal to the opportunity cost.

The theory implies that if one can observe prices and expected cash flows one can infer the investor's opportunity cost. The DCF model applies this logic to equity investment in order to infer the opportunity cost of equity. It is assumed that cash flows to investors consist of dividends and that stock prices reflect investors' expected dividends and the opportunity cost of the investment. If we observe prices of equity and estimate all future dividends that the equity gives title to, then one can infer the opportunity cost of equity. (Exhibit A2-3, pp. 26-29; Exhibit B1-9-6, McShane Evidence, Appendix F, Appendix C, p. C-1)

An attractive feature of the DCF model is that it assumes, unlike the CAPM, that investors hold realistic investment horizons; both short and long-term investors estimate all dividends that the firm will provide over its lifetime. As with the CAPM, a significant disadvantage to the Commission is that for FEI none of the inputs, for example, price, dividends, or opportunity cost, are directly observable. The equity of the benchmark utility is held by Fortis Inc. and not actively traded. Therefore, future dividends are in the eye of the beholder as is the opportunity cost of capital. As a result, the opportunity cost estimate rests entirely on inferences that are commonly based on comparable firms. Not only should these firms be comparable, they should also have actively traded equity, and a source for estimating expected dividends.

Simplifying assumptions make the task of estimating dividends easier and the evidence submitted was all based on one of two simplifications or models. The 'Perpetual Constant Growth' model assumes that investors estimate the next dividend to be paid by the company and a single rate at which dividends will grow in perpetuity. The validity of the constant growth model is reduced when the estimated growth rate comes close to the opportunity cost (as this implies an extremely large stock price) and the model is invalid if the expected growth rate is greater than or equal to the opportunity cost of equity. The second model, 'the multi-stage growth' model, also requires an estimate of the next dividend to be paid but then allows investors to see multiple stages of constant growth; for example, the investor might expect growth of 4 percent for the next five years, 3 percent for the 5 years after that, followed by a constant perpetual growth rate of 2 percent starting

11 years hence. Although the long-term perpetual growth stage must meet the same growth restrictions as the constant growth model, the earlier stages are not restricted in this way. Therefore, multi stage growth models allow considerable more flexibility in dealing with growth forecasts. The Commission Panel has considered DCF-based ROE estimates presented by Ms. McShane, Dr. Vander Weide, and Dr. Safir.[6] Dr. Booth's DCF estimate for the market as a whole was used as a check on his CAPM estimate and is discussed with that estimate previously in Section 5.2.

1) Ms. McShane's estimates

Ms. McShane provides five different estimates with ROE estimates based on the DCF model. The estimates range from 8.6 percent to 11 percent. The estimates were variously based on 12 US Utilities or 5 Canadian utilities. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 113) FBCU submit that: "The application of both constant growth and three-stage models to the two samples supports a DCF cost of equity of approximately 9.1% to 9.8% (mid-point of approximately 9.4%)." (FBCU Final Submission, pp. 105-107) The FBCU also point out that Ms. McShane relied primarily on the consensus (mean) of analysts' earnings growth rate forecasts as the proxy for investors' long-term growth expectations, minimizing the need to superimpose on the analysis her own subjective view of growth expectations. (FBCU Final Submission, p. 106) Ms. McShane recognizes, however, that the forecast period for analysts' long-range earnings and dividend forecasts is typically three to five years over a business cycle (Exhibit B1-9-6, Appendix F, Appendix C, p. C-4), and that extending these forecasts into perpetuity in the constant growth model can overstate expected return. (T4:664-665)

2) Dr. Vander Weide's estimates

Dr. Vander Weide only presents evidence based on a constant growth DCF and only for a sample of US Firms. He relies on I/B/E/S Thomson Reuters Mean Growth forecasts to estimate dividend growth. Dr. Vander Weide's application of the DCF model to his comprehensive group of utilities produced a result of 10.3 percent, and to his smaller group of utilities, 10.0 percent, including 0.50 percent for flotation costs. (Exhibit B1-9-6, Vander Weide Evidence, Appendix G, pp. 27-31; Exhibits

[6] Dr. Booth employed a Constant Growth model but only to estimate the market wide expected return. This was used as a check on his CAPM estimate and so is not included in this discussion.

6 and 7 of his evidence) The FBCU submit that "…Dr. Vander Weide's DCF estimates are reasonable and should be given significant weight." (FBCU Final Submission, p. 108)

3) Dr. Safir's estimates

Dr. Safir uses a two stage DCF model to develop two estimates; one of 8.99 percent based on 5 Canadian firms and one of 8.86 percent based on a sample of 18 US utilities, before adding flotation costs amounting to 5 percent of the initial ROE estimates. (Exhibit C4-9, pp. 24-26, and Schedules 3 and 4)

Commission Panel Discussion

The Brattle Report observes: "The DCF approach is conceptually sound if its assumptions are met, but can run into difficulty in practice because those assumptions are so strong, and hence unlikely to correspond to reality." Elsewhere the report is more specific: "The major source of debate for the DCF model is determining the dividend growth rate, particularly for the long-term. There is generally no publicly available data on forecast growth rates for periods longer than 5 years." (Exhibit A2-3, p. 30)

The FBCU urges the Panel to give the DCF considerable weight, while the AMPC/CEC submits that "a DCF analysis can provide a helpful "check" on CAPM estimates, but the Commission should be cautious not to rely too heavily on it." (FBCU Final Submission, p. 89; AMPC/CEC Final Submission, p. 41)

The Commission Panel is of the view that, notwithstanding the concerns expressed about the approach, considerable weight should be given to the DCF but also accepts that caution should be used in assessing the growth estimates presented. A number of specific concerns arise with respect to the evidence presented:

a) **Reliance on analysts' short-term forecasts as the long run forecasts in constant growth formulas**:

This reliance appears in the single stage models presented by Ms. McShane and Dr. Vander Weide. For instance, Ms. McShane's estimate based on Canadian comparable firms assumes perpetual dividend growth of 7.5 percent. Since this is larger than her estimate for long run GDP growth of 4.3 percent, Ms. McShane seems to imply that FEI will grow to be an increasingly larger segment of the economy. This is inconsistent with the evidence presented in Appendix F of her testimony where she enumerates many reasons why consumers, both residential and commercial, will migrate from natural gas to other sources. Similarly, Dr. Vander Weide's estimates of the cost of capital use short-term analysts' forecasts to estimate the constant growth model. Similar to Ms. McShane, the resulting implication is that FEI will become a larger component of the economy over time, a conclusion that seems inconsistent with FEI's submissions regarding a shrinking market share and falling customer capture rates. (FBCU Final Submission, p. 53) We also note that Dr. Vander Weide included firms whose growth rate exceeded his estimate of the cost of equity in his comparable firms. As noted above, such a growth rate is inconsistent with the DCF constant growth model yet were included in his sample without adjustment. This calls into question the DCF estimates presented by Dr. Vander Weide.

The Panel finds that the use of analysts' forecasts is more consistent with the multi-stage models where the analyst forecasts can inform the early stage and longer term forecasts, such as of GDP growth, can inform later stages.

b) **Reliance on comparable firms operating in the US**:

The AMPC/CEC submits that the use of US based comparable firms renders DCF estimates of limited value. In their submission, AMPC/CEC cites Dr. Booth as follows:

> "[In the past] we had lots of pure play utilities in Canada, where you could do a DCF. In particular, all the local telephone companies were still regulated by the CRTC on a rate of return rate based method, and we had Island Telephone traded, Maritime Tel traded, NewTel traded, Bruncor Traded, Bell Canada traded, B.C. Tel traded. So we had a lot of traded rate of return regulated utilities that we could actually do DCF tests on. Unfortunately, they don't exist anymore." (T8:1493-1494)

While the Commission Panel concurs with the concern about comparability of US based firms, it also agrees with the argument of FBCU that, given the paucity of comparable Canadian firms, also recognized by Dr. Booth, augmenting Canadian data with US firms is appropriate. (FBCU Final Submission, p. 94) The Panel also recognizes the need for careful informed judgment in adjusting the US based estimates to reflect differences in the respective environments.

c) **Analysts' forecast bias**:

Given the heavy reliance on the forecasts of equity analysts, the AMPC/CEC submit that analyst bias may inflate DCF ROE estimates. (AMPC/CEC Final Submission, p. 59) FBCU argues that analysts' forecasts for utilities are not biased. (FBCU Final Submission, p. 111) The Brattle Report notes that studies have shown that analysts' forecasts are likely to be more accurate in utilities than in other sectors and bias is likely to be less in utilities than other sectors. (Exhibit A2-3, pp. 28-29)

The Panel finds that there is reason to be cautious of potential analyst bias in the utility sector. The expert testimony at this time does not, however, convince the Panel that an adjustment for analyst bias should be made. The Panel expects that future hearings will be informed of the latest research on bias in the analyst's reports on the utility sector.

Overall Assessment

The Commission Panel finds that the constant growth DCF models presented have growth assumptions that render the estimates questionable given the discussion above. Therefore, we place little weight on the submitted estimates that are based on the constant growth DCF. The estimates that the Panel found most helpful are Ms. McShane's multi-stage estimates in the range of 8.6 percent to 9.2 percent and Dr. Safir's estimates of 8.86 percent to 8.99 percent (two-stage). (Appendix F) Applying the appropriate judgment required, **the Commission Panel accepts an 8.9 percent DCF based estimate of the opportunity cost of equity.**

5.4 Equity Risk Premium Models

5.4.1 Introduction

FBCU's witnesses Ms. McShane and Dr. Vander Weide each provided results from various models, classified as equity risk premium models. Ms. McShane provided the results of three different 'types' of ERP models, comprising numerous estimates. Dr. Vander Weide used two types of ERP models, which he termed "Ex-Ante" and "Ex-Post" risk premium tests, and used two different samples for each of the two types of tests. None of the other witnesses relied on the ERP.

The Brattle Report summarizes the form and some of the issues concerning ERP models. According to the report, the ERP is frequently implemented using either a historical estimate of the risk premium or a forward-looking or expected risk premium. It notes that the historical risk premium is commonly estimated as the historical spread between equity and debt returns, so the primary choices for the analyst become which equity returns and debt instrument to use as well as the sample period over which the estimate of the spread (i.e., the risk premium) is to be based. The Brattle Report states that it is important that the analysis is consistent in its choice of a debt instrument to determine the cost of debt and that used to determine the risk premium. It also notes that the realized risk premium is highly dependent on the time period over which it is estimated, so that choice is also important. (Exhibit A2-3, p. 31)

The Brattle Report states that the forward-looking model requires that the analyst determine a proper measure of the cost of debt and how to estimate the expected risk premium. It says that because the yield to maturity of an investment grade bond serves as a proxy for the expected return, yield to maturity measures are natural candidates for the expected bond cost. However, determining the expected equity return is more difficult and requires the reliance on an estimation technique. It notes that it is common to rely on DCF models to determine the risk premium in the forward-looking version of the model. (Exhibit A2-3, pp. 31-32)

5.4.2 Discussion of the ERP Method and Results

The Brattle Report states that the risk premium model is a derivative of the CAPM so the comments that apply to the CAPM also apply to the Risk Premium Model, but that "…the Risk Premium Model does not have the same level of theoretical support. The tie between theory and implementation is weakened because the interest rate in the Risk Premium Model is not necessarily equal to the risk-free rate and the risk premium is not explicitly based upon the product of the investment's beta and the MRP." (Exhibit A2-3, p. 33) Moreover, there is a concern that the historical risk premium approach to the ERP assumes that a historically realized risk premium is an appropriate measure for expected returns, but that over any given period, especially short periods, realized returns can differ substantially from expected returns. (Exhibit A2-3, p. 31)

A strength of the model identified in the Brattle Report is that the information on which the model relies is auditable. However, it notes that because inflation and other factors that are not directly related to the cost of equity capital may affect bond yields, the model will not necessarily produce like results for like conditions. It further states that the implementation of the model largely determines its ability to capture the systematic risk of companies, noting that, unless a forecasted return for relevant companies is used, the model will be unable to estimate reliably the cost of capital across different economic conditions. (Exhibit A2-3, pp. 34)

Commission Determination

The purpose of a rate of return model is to provide structure to the discussion of 'what a fair rate of return is.' Models used to assess this question provide structure and clarity and, in turn, a basis for the data to consider the appropriate interpretation to give it and the estimates.

The lack of a strong theoretical footing for ERP, as noted in the Brattle Report, may explain the large number of ERP estimates submitted to the Panel and the potentially intractable discussion of the merits of the models. There is simply little to help focus the analysis and as a result many models can be submitted as 'true' even though there is little on which to judge the validity of the submission.

The large number of estimates along with the absence of a compelling framework raises the following reservations about the estimates and indeed about the entire approach:

1. The models combine elements of the CAPM and the DCF with other ad hoc adjustments. Since evidence was presented on both the CAPM and DCF, it is not clear what is added by looking at these alternatives.

2. While it is not clear what is gained through these ERP models, it is clear that clarity is lost. In particular, the assumptions used in various estimates are difficult to evaluate. Ms. McShane, for instance, uses return estimates based on a sample of US firms with the 30-year Canada Bond rate in some estimates of the risk premium but in others uses 30-year A-rated utility/government bond yield spreads. (Exhibit B1-9-6, Appendix F, p. 99) Similar ad hoc assumptions are also found in Dr. Vander Weide's analysis. For instance, AMPC/CEC point to Exhibit C6-21 to demonstrate that if bond returns rather than bond yields were used in the analysis, the average Ex-Post risk premium for utilities would be approximately 4.47 percent or 2.3 percent less than Dr. Vander Wiede's estimate. Consequently, the AMPC/CEC argues that the Ex-Post estimates of Dr. Vander Weide must be ignored or if not ignored, then reduced by 2.3 percent. However, FBCU state that it is appropriate to use bond yields as the true risk-free rate. It is not clear, however, why the risk free rate is not estimated using a risk free return.

   Again, while judgment is always needed to evaluate estimates, without a theoretical base, there is no consistent way in which these differences of opinion can be assessed.

3. Since the model variations are ad-hoc they are subject to the concern that they may be subject to a "fishing' expedition" criticism. In contrast, while we can obtain various results from the CAPM or DCF models by changing parameters such as the risk premium in the CAPM or the growth rate in the DCF, the reasonableness of the selected parameter can be questioned.

Given these concerns along with the fact that there is ample evidence on both CAPM and DCF based estimates, the Panel places no weight on the ERP estimates submitted.

5.5 Comparable Earnings Approach

The Brattle Report states notes that the CE method is one of the traditional approaches to the cost of capital estimation, but that it does not have a financial economics foundation or strong theoretical basis. The report states that the legal decision, *Federal Power Commission et al v. Hope Natural Gas Co.,*[7] which stated that the return to the equity owner should be commensurate with returns on investment in other enterprises having corresponding risks, is often cited in the use of comparable earnings, but that neither the Canadian nor the US Supreme Courts has identified any specific methodology to determine a "fair return." (Exhibit A2-3, pp. 11, 36) The Commission Panel observes that much has been learned about financial economics since 1944. In particular, the notion of a comparable investment has been carefully cast in terms of investments in portfolios of

---

[7] 320 U.S. 591 (1944); 64 S. Ct. 281; 88 L.Ed. 333 (1944) U.S. Lexis 1204

comparable risk since portfolios are more efficient in achieving any expected return than is a single security.

The CE method requires the use of a sample of unregulated companies as comparators, since the use of regulated companies to estimate the comparable cost of capital would be circular. The Brattle Report notes that because the comparable companies are unregulated entities, it is necessary to adjust for any risk differences between the sample companies and the target company, and because the estimates from the model do not come from regulated companies or activities, the method does not recognize the regulatory context in which the cost of capital is being applied. (Exhibit A2-3, pp. 35, 38)

The Brattle Report states that a major issue with the comparable earnings method is whether realized book returns are a good proxy for the return that investors expect going forward and notes that it is a backward looking measure with no consideration of current market conditions. (Exhibit A2-3, pp. 36-37)

Ms. McShane submits that the fair return standard "…is only satisfied if the utility can attract capital on reasonable terms and conditions, its financial integrity can be maintained ***and*** the return allowed is comparable to the returns of enterprises of similar risk. The BCUC has recognized that the comparable return requirement is distinct from the capital attraction standard…." (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 8) [emphasis in the original] In her view, the comparable earnings test is an implementation of the comparable returns standard, as distinguished from the cost of attracting capital standard and it is critical that the regulator recognize the comparable returns standard when setting a fair return. (Exhibit B1-9-6, Mc Shane Evidence, Appendix F, p. 114)

Ms. McShane submits that the comparable earnings test, which measures returns in relation to book value, is the only test that can be directly applied to the equity component of an original cost rate base without an adjustment to correct for the discrepancy between book values and current market values.

Ms. McShane arrived at her comparable earnings estimates based on the earnings on book-value of 21 unregulated Canadian companies from 2004-2011. (Exhibit B1-9-6, Appendix F, pp. 113-116) She arrives at the following result: "To recognize the unregulated companies' higher risk, a downward adjustment of 125 to 150 bps to their returns on equity was made, resulting in a comparable earnings result in the range of 11.0% to 12.0%." (Exhibit B1-9-6, Appendix F, p. 116)

To complete her comparable earnings estimate, she assesses the need for a market/book adjustment to the comparable earnings results. She submits that "[t]he similar to lower average market/book ratios of the Canadian sample of unregulated companies relative to both the Canadian and U.S. equity market composites indicate no evidence of market power. Thus there is no rationale for making an additional downward adjustment to the unregulated Canadian companies' returns on equity due to their market/book ratios." (Exhibit B1-9-6, pp. 116-17)

Dr. Booth submits that the average ROE increases when one starts adding low-risk firms to a comparable earnings sample and then progressively decreases as more risky firms are added, particularly after the lowest risk firms are added. He argues that: "…to get a high ROE from a sample of comparable earnings firms simply means coming up with "reasonable" screens to narrow down the sample and exclude those firms with significant losses. (Exhibit C6-12, p. 6)

He used book-value based estimates for Corporate Canada as a whole, using Statistics Canada reported earnings for the period 1987 to 2011 and the TSX composite for the same time period. He arrived at a CE estimate for the Canadian market of 9.3 percent, and says that "Like the overall stock market return this then needs to be lowered for the lower risk attached to regulated utilities." (Exhibit C6-12, Appendix E, pp. 3, 7, Schedule 2)

Dr. Booth submits that CE "…is totally unreliable unless a market to book adjustment is made which is rarely the case." (Exhibit C6-15, BCUC 1.39.0) He also submits that a "…market to book adjustment is needed since low risk firms usually have market power which is reflected in higher ROEs. It is incorrect to then allocate to a utility an ROE from a sample of firms that reflects market power when regulation is designed to remove this market power." (Exhibit C6-15, BCUC 1.67.1)

Dr. Booth also says that a problem with looking at past ROEs is that they are earned on historic accounting book equity that does not reflect what can be earned on investments today. (Exhibit C6-12, Appendix E, p. 5)

The AMPC/CEC argues that the Commission should place little or no weight on the comparable earnings test. (AMPC/CEC Final Submission, pp. 38, 60)

Dr. Safir used two market-value based estimates: one for the same Canadian sample of 21 companies used by Ms. McShane; the other based on a sample of 31 US companies in the consumer goods, industrial goods or service sectors using the same sample selection criteria as Ms. McShane used for her Canadian sample. (Exhibit C4-9, pp. 28-29)

Dr. Safir calculated his comparable earnings estimates "…using net income and market value of equity…." He submits that because his comparable earnings estimates were calculated using market-based values instead of book value, they more accurately capture the conditions in the current capital markets in which the benchmark firm would be competing for capital. He goes on to say that his method accounts for factors such as inflation, since both the net income and the stock prices will reflect the level of inflation occurring at the time these numbers were reported and that "[b]ook value-based calculations of comparable earnings will not account for inflation." (Exhibit C4-9, p. 30) Using his market-value based method of calculating CE Dr. Safir arrived at estimates of 6.85 percent for his Canadian sample and 5.81 percent for his US sample. He submits that the Canadian estimate should be given twice the weight of his US estimate and arrives at a weighted average estimate of 6.50 percent. (Exhibit C4-9, p. 33)

Dr. Vander Weide did not provide a CE estimate.

Commission Determination

The fundamental issue regarding the CE test is its lack of a basis in financial economics. The approach requires a sample of unregulated companies of similar risk, but creating a sample of unregulated companies that are, and can be shown to be, of similar risk is difficult without a theoretical basis such as the CAPM or the DCF. Dr. Booth has pointed out the issues that arise when even 'reasonable' screens are used to eliminate companies from the entire universe of companies to create a sample. Moreover, the CE method is retrospective, whereas the ROE to be established for the benchmark utility is prospective.

In her evidence, Ms. McShane submits that: "The economic principle guiding the fair return is the opportunity cost principle." She also submits that one of the requirements of the FRS is that the return allowed is comparable to the returns of enterprises of similar risk and that it is critical that the regulator recognize the comparable returns standard when setting a fair return. She also states that the CE test is an implementation of the comparable returns standard and is to be distinguished from the cost of attracting capital standard. (Exhibit B1-9-6, McShane Evidence, Appendix F, pp. 2, 8, 114)

During cross-examination a discussion on whether the comparable earnings test reflects an investor's opportunity cost concluded with the exchange below:

COMMISSIONER GIAMMARINO: But you would agree that in terms of an opportunity cost, it doesn't match up that closely to what we would consider the exact opportunity cost to the investor.

Ms. McSHANE: A: No, it is not an opportunity cost in the same sense that you were talking about. (T5:732-35)

The Commission Panel addressed the FRS in Section 2 and recognized that a fair or reasonable overall return on capital should be comparable to the return available from the application of the invested capital to other investments of like risk (comparable investment requirement). However, the Commission does not accept that this requirement means that it must use the comparable earnings method as a means of determining what return is required to meet the FRS. Modern finance theory has clearly established that comparable risk is assessed relative to a *portfolio* rather than a single stock. This is indeed the basis of the CAPM and other extensions of risk return modules. Searching for individual firms of comparable risk is consistent with this only if the comparison recognizes non-diversifiable risk as the relevant characteristic. This is exactly what is done when CAPM comparators are sought. But this is ignored when companies are considered comparable on dimensions other than systematic risk.

The preceding discussion highlights some of the serious problems the comparable earnings method contains as a means of determining the return required to meet the FRS. **Consequently, the Commission Panel places no weight on the comparable earnings results.**

5.6 Allowance for Financing Flexibility

Ms. McShane described financing flexibility allowance as intended to cover three distinct aspects: (1) flotation costs comprising financing and market pressure costs arising at the time of the sale of new equity; (2) a margin, or cushion, for unanticipated capital market conditions; and (3) a recognition of the "fairness" principle (Exhibit B1-9-6, McShane Evidence, Appendix F, p. F-1). Flotation costs and financing flexibility adjustments are typically applied to the market-based cost of equity estimates, i.e., the CAPM and the DCF models.

Ms. McShane provided an allowance of 50 basis points for each of her market based tests in order to maintain the market value at a small premium to the book value. In the alternative, should the Commission rely only on the market-based tests, Ms. McShane proposed an allowance for financing flexibility at 1.0 percent. (Exhibit B1-20, BCUC 75.2.1)

Dr. Vander Weide provided an allowance of 50 basis points for flotation and financing flexibility. (Exhibit B1-9-6, Vander Weide Evidence, Appendix G, p. 35)

Dr. Booth provided an allowance of 50 basis points, stating that the market opportunity cost should be adjusted upwards to include issuing costs or a financial flexibility adjustment to make sure that shares can always be sold to net out the original cost included in the rate base, which is all that earns the fair ROE. He also noted that most regulators in Canada have allowed 50 basis points for these new issue costs (Exhibit C6-12, p. 8).

Dr. Safir referred to a survey of flotation costs, which determined them to be approximately 4.5 percent of the recommended rate of return. Based on the 4.5 percent, Dr. Safir applied 5 percent of the rate of return, an equivalent of around 32 to 40 basis points for his CAPM models and 47 bps for his DCF model, to reflect the marginally higher costs that would be faced by Canadian issuers either crossing the border to utilize the US market or in issuing in the smaller Canadian capital market. (Exhibit C4-9, pp. 16-18)

Commission Determination

The Commission Panel accepts the allowance for financial flexibility of 50 bps added to the CAPM and DCF tests in determining the fair ROE. As indicated in Section 5.5, the two market-based tests, CAPM and DCF are given equal weight in the determination of the allowed ROE for the benchmark utility.

With reference to Ms. McShane's proposed additional 50 bps if the CE test is not accepted, the Commission Panel is of the view that each test to estimate the fair return is applied separately to provide a different perspective and each test's results are not contingent upon the results of other tests. Therefore, the Commission Panel does not accept the conditional 50 bps in Ms McShane's alternative proposal.

5.7 Fair Return on Equity – Commission Determination

The Panel finds that the DCF and CAPM should be given equal weight in determining the ROE. Moreover, the Panel finds that CE and other ERP models have insufficient merit to be accorded any weight in the determination of the fair ROE. Considering the CAPM based estimate of 7.64 percent and the DCF estimate of 8.9 percent, the Panel concludes that the ROE, before adjustment for financing flexibility, of 8.25 percent is an appropriate base as it falls in the midpoint range of the two estimates. When an allowance for financial flexibility of 0.5 percent is added, the resulting ROE is 8.75 percent, to be effective January 1, 2013, provided for by Order G-47-12 and confirmed in Order G-187-12. **The ROE will be effective until December 31, 2015, subject to variation commencing January 1, 2014, by the Automatic Adjustment Mechanism formula discussed and adopted in Section 6.**

FEI is to file within 30 days of this Decision and accompanying Order G-75-13 amended rate schedules in accordance with paragraphs 1 and 2 of Order G-75-13 as well as a proposal on the treatment of the refundable portion of the rates collected since January 1, 2013. FEI shall inform all affected customers of the final rates by way of customers notice.

6.0 AUTOMATIC ADJUSTMENT MECHANISM

6.1 Introduction

In 1994, the Commission determined that the Benchmark ROE was to be estimated annually by an Automatic Adjustment Mechanism (AAM).[8] This AAM was eliminated by Order G-158-09 issued concurrently with the 2009 Decision. In eliminating the AAM the Commission stated that: "... in its present configuration, the AAM will not provide an ROE for TGI for 2010 that meets the fair return standard." (2009 ROE Decision, p. 72)

One of the stated purposes of this proceeding was to review the possible return to an AAM for setting an ROE of the benchmark utility and examine potential AAM models. In this Section, the Commission determines that:

- Reinstituting an AAM formula for annually setting the ROE for a benchmark utility between proceedings is appropriate.
- A two-variable model AAM is to be instituted to set the benchmark ROE on an annual basis commencing in the 2014 calendar year for a period of two years.
- Implementation of the model will be subject to the actual long Canada bond yield meeting or exceeding 3.8 percent.
- The new formula will initially utilize the ROE of 8.75 percent as determined in Section 5.7.

6.2 Should the Commission Re-institute an AAM?

In considering re-instituting an AAM, the Commission Panel reviewed proposed AAMs to determine whether they would meet the Fair Return Standard or whether, as FBCU submit: "The Fair Return Standard is best met in intervening years until the next comprehensive cost of capital reviews by holding the ROE constant." (FBCU Final Submission, p. 153) In addition, the Panel examined the status of AAMs in other Canadian regulatory jurisdictions.

---

[8] In the Matter of Return on Common Equity – BC Gas Utility Ltd., Pacific Northern Gas Ltd., West Kootenay Power Ltd., -- Decision and Order G-35-94, June 10, 1994.

6.2.1 Status of AAMs in Other Canadian Jurisdictions

The Brattle Report surveyed the cost of capital practices in Canada including the formulas used to set the ROEs in Ontario and Quebec. (Exhibit A2-3, pp. 64, 72)

In the 2009 Decision, FBCU was directed to complete a study of AAM alternative formulas and report to the Commission. In compliance, FBCU filed the 2010 report, "A Review of Automatic Adjustment Mechanisms for Cost of Capital" prepared by Concentric Economic Advisers (Concentric). The 2010 Report provided an examination of the use of AAM formulas in other jurisdictions, contrasted these with alternatives and considered the merits of various approaches. While not recommending that a formula be adopted, Concentric identified attributes that should be considered if an AAM is adopted in the future. (Exhibit B1-9-6, Appendix I) In this proceeding, FBCU again engaged Concentric to provide an update of its analysis, which examined the use of ROE formulas in other jurisdictions. The update included the following observations with regard to Canadian jurisdictions:

- The Ontario Energy Board (OEB) continues to rely on its AAM which it modified in 2009. The modified formula is based on 50 percent of the change in forecast long-term Canada bond yields and 50 percent of the change in observed A-rated utility bond index over the 30-year Canada Bond yield.
- In Quebec the Régie de l'énergie (Régie) modified its previous formula in 2012 to incorporate 50 percent of the change in utility bond spreads in addition to the existing formula's 75 percent of change in government bond yields.
- In its December 2011 Decision, the AUC determined that the credit market remained volatile and therefore decided not to employ an AAM for 2012. The AUC indicated that it was not prepared to preclude a return to some form of formula-based AAM in future once the capital markets had stabilized.
- The Newfoundland and Labrador Board of Commissioners of Public Utilities, in June 2012, approved an 8.8 percent ROE (which was not set by formula) for Newfoundland Power stating that this was within a range of reasonable values. The Board did not disavow or abandon the formulaic approach for future rate proceedings.

Concentric has not changed its position on AAMs and stated that: "periodic rate hearings remain the only reliable method for the determination of utility ROE's." However, Concentric noted that Canadian regulators have recognized that a sole reliance on simple relationships to government bonds cannot be relied upon to estimate ROE. Concentric points out that both Ontario and Quebec have incorporated utility bond spreads in their formulas and notes that this mitigates one fatal weakness of past AAMs. Concentric views the two variable methodology utilized by Ontario as an improvement with a remaining concern being the lack of a specific link to the cost of equity , other than that conveyed by bond yields. (Exhibit B1-9-6, Appendix I, Concentric Update Report, pp. 1-4, 11)

The Commission Panel notes that both the OEB and the Régie formulas are variations of the model proposed by Dr. Booth and are discussed further in Section 6.2.2 below.

It appears that there is some acceptance by utility regulators in Canada of an AAM formula based on a two-variable model that uses the long-term Canada bond rate as a proxy for a risk free rate and a change in utility bond spreads as a proxy for credit risk. There is, however, reluctance in some jurisdictions to institute an AAM given the volatility of Canadian capital markets in recent years.

6.2.2 Submissions by Parties

AMPC/CEC

AMPC/CEC submit that the Commission abandoned the AAM in 2009 because it did not provide a fair return citing the following passage from the 2009 Decision: "the recent flight to quality has driven down the yield on long-term Canada bond yields, while the cost of risk has been priced upwards." Therefore, AMPC/CEC submit that the question for the Commission is, "what formula will allow it to return to an AAM, while ensuring that the results are fair in light of the current financial conditions and the conditions FEI might encounter going forward." (AMPC/CEC Final Submission, p. 62)

AMPC/CEC support a return to an AAM based on its contribution to regulatory efficiency because an AAM reduces the frequency of periodic ROE reviews. They note that FBCU have suggested that 3-5 years is a reasonable gap between comprehensive ROE reviews. AMPC/CEC points out that if the Commission agrees with this, an AAM would likely allow the reviews to be closer to five years rather than three, resulting in considerable efficiency benefits. (AMPC/CEC Final Submission, pp. 62-63)

Dr. Booth states that "The key problem with 'old' ROE adjustment models was that they *only* linked the ROE to the forecast long Canada yield. As a result, during the financial crisis the ROE formula indicated declining ROEs while at the same time the utility cost of debt was increasing. An enhanced ROE formula has to deal with this, which can be done by incorporating the credit market adjustment I have used in my direct ROE estimates." (Exhibit C6-12, pp. 97, 100)

Dr. Booth recommends "an ROE adjustment model where ROE adjusts by 75% of the forecast change in long Canada bond yields and 50% of the change in the credit spread. This would be subject to a minimum forecast long Canada bond yield of 3.80% … Similar models are in use by the Régie and OEB." (Exhibit C6-12, p. 3) Dr. Booth selects 3.80 percent as the "floor" stating that this "is the lowest rate consistent with a normal cyclical low." (Exhibit C6-12, pp. 97, 100)
AMPC/CEC argue that Dr. Booth's enhanced two variable ROE formula addresses the concern with the old ROE formula that during periods of financial crisis the allowed ROE and utility borrowing costs move in opposite directions. They argue that Dr. Booth's formula obviates FBCU's concern that the AAM won't work because of the current unusual business cycle. The proposed 3.8 percent floor acts like a fixed rate ROE until the long Canada bond yields return to normal, and it provides an adjustment mechanism for periods when conditions are more typical. (AMPC/CEC Final Submission, p. 64)

<u>ICG</u>

Dr. Safir believes that an AAM for a limited number of years is appropriate because "It is simply not economically efficient to revisit the entire ROE setting mechanism annually" and also states that "the AAM is administratively efficient, resulting in significant savings by avoiding costly, annual rate hearings." In Dr. Safir's view, AAMs that reference long-term bond rates, such as the one previously used by the BCUC, are good ways to account for near term influences that affect a fair ROE. (Exhibit C4-9, pp. 36-37)

ICG observes that during the interim years between periodic cost of capital proceedings an AAM formula is more likely to result in an ROE that meets the FRS than no formula. It submits that the Commission should establish an AAM similar to the one discontinued by the Commission in 2009 that referenced long-term bond rates with a three year effective period. It would differ from the previous Commission AAM in that it would use a five year average for the forecast long-term Canada bond yield. (Exhibit C4-9, pp. 36-38; ICG Final Submission, p. 32; T7:1187)

ICG concedes that a multiple factor model may be more likely to meet the FRS than a single factor model, but given that the single factor model has been tested over a long period, it has been recommended to the Commission. (ICG Final Submission, pp. 32-33)

BCPSO

BCPSO submits that an AAM is beneficial because it ensures that the benchmark utility will not operate for more than a brief period of time with a higher than required ROE and therefore supports reinstatement of an AAM. (BCPSO Final Submission, pp. 19-20)

FBCU

FBCU does not support the return to an AAM. FBCU's main concern with the AAM is that the basis upon which the annual ROE adjustments are being made may be suspect. They submit that an AAM relies on a formula with a limited number of inputs that could never capture the complex factors affecting ROE, and that an AAM likely relies on long Canada bond yields and corporate spreads, which are still affected by atypical market conditions. In addition, any formula relies on imperfect proxies. In their view, the application of the FRS requires a significant degree of analysis, market information, and judgment that evolve over time. Formula parameters are static and based on historic relationships and fundamental relationships may shift, leaving the formula out of touch with current market conditions. FBCU take the position that there is no formulaic way to assign a value or weighting to specific risk factors or utility/utility sector characteristics that would apply across multiple utilities and generate the appropriate cost of capital for each one. This is supported by Ms. McShane who submits that the Commission should continue to address the appropriate cost [of capital] on a case-by-case basis: "There is no 'one size fits all' cost that should be determined by means of an interest automatic adjustment mechanism." (FBCU Final Submission, p. 153-156; Exhibit B1-9-6, p. 33; Exhibit B1-9-6, McShane Evidence, Appendix F, p. 7)

FBCU prefer to have the allowed ROE and capital structure set through a traditional process and remain constant between the periodic (three to five year) formal reviews, subject to events occurring that bring the results out of alignment with the FRS, which could result in an unscheduled full review process. This is preferable to having updates made on a basis that the FBCU believe is suspect. (Exhibit B1-20, BCUC 2.113.1)

FBCU argue that there is no efficiency gain associated with implementing the AAM, if there are to be periodic reviews. FBCU further argue that the regulatory burden associated with periodic cost of capital reviews is the same as that associated with periodic reviews with annual formula-driven ROE changes in the interim. FBCU also argue the FRS is best met in the intervening years until the next comprehensive cost of capital reviews by holding the ROE constant. (FBCU Final Submission, pp. 153-156)

FBCU further submit that "The rationale for why the Commission discontinued the AAM remains valid today. Meeting the Fair Return Standard is not optional." FBCU state that "All of the experts agree that we are still experiencing unusually low interest rates, and the ability of any AAM to produce fair results is far from certain [when such conditions exist]." (FBCU Final Submission, p. 153)

With respect to the positions taken by Dr. Safir and Dr. Booth, FBCU make the following submissions:

1. FBCU submit that Dr. Safir is proposing to return to an AAM that has already been rejected by the Commission, with the only difference being the starting point for measurement of changes in the forecasted long Canada bond yields (i.e., the use of the five-year average forecast). They cite Ms. McShane's statement that there is an inverse relationship between long-term government bond yields and the utility risk premium. FBCU also argue that Dr. Safir's use of a five-year average forecast Canada bond yield as the base line in the formula is problematic because it suppresses ROEs despite increases in long Canada bond yields. FBCU submit that while this five year average is intended to compensate for present unusually low interest rates, it would be better to postpone consideration of a formula, rather than implement a "quick fix" that artificially suppresses the ROE. (FBCU Final Submission, pp. 159-160)

2. FBCU submit that the AAM proposed by Dr. Booth is biased downwards. FBCU notes that the current long Canada bond yield is well below the 3.8 percent that Dr. Booth employs as the floor, and points out that while he expects rates to increase, he does not expect the forecast to rise above the 3.8 percent for at least three years. FBCU submit that the combination of rock-bottom forecast yields and a slow rise in interest rates has two implications. First, rock-bottom interest rates means that further declines are not likely. Second, any increase in the forecast long Canada bond rate will not result in an increased ROE. In addition, FBCU submit that the cross-examination of Dr. Booth indicates that he expects credit spreads to fall while the long term Canada bond yield remains below 3.8

percent, an expectation shared by Mr. Coyne. FBCU propose that the result of this will be a progressively lower benchmark ROE after 2013 if Dr. Booth's formula is employed. (FBCU Final Submission, pp. 160-161)

FBCU's position is that if the Commission requires an ROE AAM, it should seek to rectify the problems of the old formula. A new formula would address changes in the equity risk premium, and not solely changes in long Canada bond yields. Any adjustment factor would need to reflect sensitivity to change in bond yields to ROE. (Exhibit B1-9-6, pp. 27-29)

Corix

Corix submits that there is a continued flight to quality and a still increasing cost of risk, so an updated AAM is not appropriate at this time. (Exhibit B2-9, BCUC 1.2.1, p. 3)

6.3 Commission Determinations

6.3.1 Re-instituting an AAM

The Commission Panel does not take issue with FBCU's argument that an AAM formula with limited inputs cannot capture all of the complex factors affecting ROE and therefore, relies on imperfect proxies. However, at the same time, the Panel is of the opinion that the issue is whether the adoption of an AAM formula is better than the alternative, which is to do nothing as suggested by FBCU and Corix. In other words, while implementing an AAM formula may not be perfect, the question is whether it better satisfies the FRS than leaving the ROE static for a period of time or conducting frequent costly and time consuming ROE proceedings. The difficulty with leaving the ROE static over a three year or longer period is that financial markets continue to change and investors' needs continue to evolve. Therefore, in the view of the Commission Panel, implementing a mechanism to capture the impact of some of these changes is far superior to the alternative of doing nothing. Furthermore, as the AMPC/CEC submits, "if there are reasonable grounds to believe the mechanism is not producing fair results, the benchmark utility always has the option of asking for a review." (AMPC/CEC Final Submission, p. 64)

The Commission Panel does not disagree with FBCU's argument that the regulatory burden associated with periodic cost of capital reviews with or without an AAM is similar. However, we are of the view that the likelihood of a requirement for more frequent ROE proceedings is reduced by having in place an AAM formula. Thus, the Panel is persuaded that the application of the AAM has the potential to contribute to regulatory efficiency.

Therefore, the Commission Panel determines that re-instituting an AAM formula for annually setting the ROE of the benchmark utility between ROE proceedings is appropriate. Additionally, the Commission Panel finds the FRS is adequately met because implementing an AAM formula better meets the standard than taking no consideration of changes in the market over a three year period as suggested by FBCU. The AAM formula to be adopted and the timing of its use is addressed in Section 6.3.2.

6.3.2 Optional AAMs to be Considered

The Commission Panel acknowledges that interest rates have been atypical in recent years and have remained at historical lows. The historical AAM used by the Commission prior to 2009 relied exclusively on a single variable formula based on the long-term Canada bond yields as a proxy for risk free rates. This model was less than fully effective for utilities because the flight to quality kept interest rates abnormally low while the risk had been priced upwards. It could not assure that the FRS could be met in extended times of low interest rates.

As noted previously, Dr. Booth proposed a two-variable model that incorporates the traditional concept of tying the benchmark utility's ROE to the "risk free" long-term Canada bond yield, and also incorporates a credit market adjustment to reflect the relationship of ROE and credit risk within the utility sector. His model also utilizes a "floor" long-term Canada bond rate of 3.8 percent as the risk free proxy until such time as long-term Canada bond yields return to a more common level.

Concentric submits that any new AAM formula should address changes in the utility risk premium and not be based solely on changes to the long Canada bond yields. While it does not recommend a formulaic approach, it does provide several potential formulaic methodologies that could be used in British Columbia (Exhibit B1-9-6, Appendix I, 2010 Report, pp. 39-45)

In summary, possible options for re-instituting an AAM include:

- The single variable model used by the Commission prior to 2009 that was based on long Canada bond yields;
- The variety of approaches offered by Concentric (Exhibit B1-9-6, Appendix I, p. 11);
- Dr. Booth's two-variable model or a variation incorporating the long Canada bond yield, a floor level of long Canada bond yield to address the atypical low interest rates, and a metric to address credit spreads.

The Commission Panel recognizes the shortcoming of the single variable model used by the Commission prior to 2009 in that it fails to satisfy the FRS when interest rates continue at abnormally low levels. Accordingly, this model will not be considered.

While Concentric has explored a number of alternative formulas that could be used in British Columbia, the Commission Panel notes that none of these have been recommended by Concentric nor have they provided evidence as to their use and effectiveness in other jurisdictions. In addition, none of the interveners has expressed support for any of these. Given this lack of support and the lack of evidence to support their efficacy and relevance to British Columbia, the Commission Panel does not endorse any of the possible alternative AAMs explored by Concentric.

During cross-examination, Commission counsel asked Mr. Coyne of Concentric what advice he would give the Commission in terms of adjustments if the Commission were adopt an AAM similar to that of the OEB and the Régie. Mr. Coyne testified that a coefficient of 0.5 was a more accurate reflection of the historic relationship to long-term Canada bonds than 0.75. (T5:827)

Dr. Booth testified that he recommended 75 bps but that he could live with 50 bps and he did not believe that there would be a big impact. (T8:1622)

The Commission Panel is persuaded that a two-variable model similar to that proposed by Dr. Booth and currently utilized in Ontario is appropriate for application to the benchmark utility within British Columbia. (Exhibit C6-15, BCUC 1.44.5 attachment)

By utilizing the 50 percent adjustment of the change in the long-term Canada bond yield as a proxy for risk free rates, it recognizes the relationship between ROE and risk while moderating the level of change resulting from any volatility in the long-term Canada bond rate. In addition, by utilizing the 50 percent adjustment in the change in the utility bond spreads, it recognizes the relationship between credit risk and ROE in the utility sector and moderates volatility in utility bond spreads. And finally, by utilizing a 3.8 percent floor for the long Canada bond yield, it recognizes the atypical relationship between ROE and cost of risk in periods of unusually low interest rates. Further, the application of similar models within both Ontario and Quebec supports it usefulness and acceptance within other Canadian regulatory jurisdictions.

Given the advantages, the Commission Panel adopts a two variable model AAM to determine the benchmark ROE on an annual basis commencing in the 2014 calendar year. The AAM formula will operate until December 31, 2015. The implementation of the model is subject to conditions outlined in Section 6.3.3. The formula will initially utilize the 8.75 percent ROE as determined in Section 5.7 as the base ROE.

The formula to be used and the basic method to determine the changes in long Canada bond forecast and the changes in utility bond spread are provided as follows:

ROE_1 ***= Base ROE (8.75%) + 0.50 x (***$LCBF_t$ ***– BaseLCBF) + 0.50 x (***$UtilBondSpread_t$ ***– BaseUtilBondSpread)***

> Where:
> ***$LCBF_t$*** is the Long Canada Bond Forecast for the test year, with a floor of 3.8 percent. The Base LCBF is 3.8%.
>
> ***$UtilBondSpread_t$*** is the average spread of 30 year A-rated Canadian Utility bond yields over 30 year Government of Canada bond yields and BaseUtilBondSpread will be determined.

6.3.3 Impact of a 3.8 percent Floor

FBCU has argued that the AAM proposed by Dr. Booth is biased downwards. The Commission Panel agrees that the potential for a downward bias does exist.

Dr. Booth has recommended that any change in the ROE be subject to a minimum forecast bond yield of 3.8 percent as this is the lowest rate which is consistent with a normal cyclical low. The Commission Panel accepts this as reasonable since it is the risk free rate for the CAPM ROE as determined in Section 5.2.

With respect to the two-variable AAM formula, Dr. Booth has acknowledged that as long as the long-term Canada bond yields are below 3.8 percent, the only variable that can affect ROE is the corporate utility bond spreads. FBCU submit that if the credit spread drops or tightens before long Canada bond rates are above 3.8 percent, the ROE will drop further from whatever the starting point is under his formula. Further, Concentric states that "a troubling aspect of Dr. Booth's proposed formula is that it sets a minimum floor LTC yield of 3.8 %, which will be applied for purposes of measuring year over year changes in the formula, but does not specify an objective bond forecast to reference for the starting point." (Exhibit B1-32, Concentric Rebuttal Evidence, Concentric Response to Interveners, p.4) The Panel notes that all parties seem to agree that long-term Canada bond yields are well below what would be considered a cyclical low and have been influenced by monetary policy. Therefore, it is reasonable to assume that the likelihood of an increase in the yields of long Canada bond is much more likely than a decrease. If this were to occur with no corresponding change in utility bond rates, the result would be a decrease in the credit spread and, consequentially, the ROE. Given that a rise in the long Canada bonds yields may be driven by monetary policy and not a change in market conditions, and there is no evidence to suggest there would be a corresponding change in utility bond rates, the Commission Panel accepts that a potential for downward bias exists. **To deal with this the Commission Panel directs that any change in ROE resulting from the AAM formula be subject to an actual long Canada bond yield of 3.8 percent being met or exceeded. Accordingly, the AAM formula will not be operative as long as the long Canada bond yield is below 3.8 percent.**

The Commission Panel has considered Concentric's submission that Dr. Booth did not specify an objective bond forecast to reference as a starting point. We are of the view that the potential for downward bias will continue if attention is not paid to setting appropriate base rates for the formula. Therefore, the Commission will seek submissions from the parties with respect to determining appropriate base levels and developing an effective methodology for deriving the inputs to the formula.

The Commission Panel understands that the conditions placed upon the implementation of the AAM formula may well result in the 8.75 percent ROE being in place for the term of this Decision ending December 31, 2015. However, in consideration of the FRS, the Panel is of the view that this is appropriate.

FEI is directed to file an application for the review of the common equity component and the ROE approved in Order G-75-13 by no later than November 30, 2015.

7.0 COST OF CAPITAL – SMALL UTILITIES

7.1 Introduction

When the Commission initiated the GCOC Proceeding, it identified the Affected Utilities, which included FEI and other FortisBC gas and electric utilities, PNG and Corix. These utilities were expected to take a lead role in filing evidence for cost of capital matters that may impact them. In addition, the Commission identified Other Utilities that "may wish to participate in the GCOC Proceeding." This list included among others:

- Big White Gas Utility Ltd. and Sun Peaks Utilities Co. Ltd.;
- Central Heat Distribution Ltd.;
- Dockside Green Energy LLP;
- Hemlock Valley Electrical Services Limited; and
- River District Energy Limited (River District).

The recent emergence of thermal energy services (TES) in British Columbia has resulted in the creation, over the last few years, of a number of new on-site thermal energy systems and district energy systems, which are subject to the Commission oversight. For instance, FortisBC Alternative Energy Service Inc. (FAES), an affiliate of FEI and a wholly-owned subsidiary of FortisBC Holdings Inc. (FHI), now owns and operates or is proposing to develop the following regulated TES projects:

- Delta School District Number 37;
- Tsawwassen Springs Development;
- PCI Marine Gateway;
- TELUS Garden Thermal Energy System; and
- Kelowna District Energy System.

Key purposes identified by the Commission Panel in its Final Scoping Document were to establish:

(i) a method to determine the appropriate cost of capital for a benchmark low-risk utility in BC and how the Benchmark ROE will be reviewed and/or adjusted;

(ii) a generic methodology or process for determining each Affected Utility's cost of capital in relation to the benchmark utility's cost of capital; and

(iii) a framework for determining the appropriate cost of capital for other smaller utilities in the province.

Related to this framework, the scope of the proceeding included the following key activities:

(i) establish a generic methodology or process for each utility to determine its unique cost of capital in reference to the benchmark low-risk utility;

(ii) in certain circumstances, develop a methodology to establish a deemed capital structure and deemed cost of debt, particularly for those small utilities without third-party debt, which would involve setting a methodology on how to calculate a deemed interest rate.

(Exhibit A-3, Appendix B to Order G-47-12)

The Commission Panel also requested submissions regarding Stage 1 and Stage 2 review. The FBCU submitted it would be most efficient to break the process down into three groups which would be handled separately: one for the FBCU, a second for the PNG and a third for micro utilities including Corix and FAES and others. (Exhibit B1-22, pp. 10-11) By Order G-148-12, the Commission Panel directed that a Stage 2 will be added to this GCOC proceeding with the schedule to be determined prior to the end of Stage 1. (Exhibit A-21)

Transition to Stage 2

The purpose of the Stage 2 proceeding is to assess the differences in short and long-term risk faced by the Affected and Other Utilities as compared to the benchmark utility FEI. Based on this assessment the Panel will then determine how the risk differentials will impact the capital structures and the allowed ROE for these utilities.

The Panel acknowledges the FBCU submission that it may be efficient, given the small size of thermal energy systems, to have a single process to address cost of capital issues for TES systems, irrespective of the provider. This would include FEI and FAES's Thermal Energy Services, and similar systems to be operated by developers or providers like Corix. (Exhibit B1-9, p. 34) The Panel also notes the previously mentioned FBCU suggestion about dividing the Stage 2 process into three groups.

In anticipation of Stage 2, this section addresses issues related to the framework for determining the cost of capital for the smaller utilities, including all new small TES utilities. The appropriate method to determine interest rates for deemed debt will also be addressed. In this Decision, the definitions of "small utilities" and "micro utilities" are used interchangeably.

7.2 Framework for Establishing an Appropriate Cost of Capital – Equity Risk Premium

7.2.1 Is Size a Risk Factor in ROE and Capital Structure Determination?

Ms. Ahern, the expert witness for Corix states "it is conventional wisdom, supported by actual returns over time, that smaller companies tend to be more risky, causing investors to expect greater returns as compensation for that risk." Ms. Ahern further explains that smaller companies, for instance, face more risk exposure to business cycles and economic conditions, both nationally and locally. Similarly, the loss of revenues from a few larger customers would have a greater effect on a small company than on a much larger company with a larger, more diverse customer base. Moreover, smaller companies are generally less diverse in their operations as well as experiencing less financial flexibility. (Exhibit B2-7, pp. 6-7)

Ms. McShane, the expert witness for FBCU states that in the assessment of investment risk, size has two dimensions that should be considered in determining a utilities common equity ratio and ROE:

1. A small utility does not have the opportunities to diversify its risks to the same extent as a larger utility. For example, assets are typically more concentrated in a limited geographic area, which limits operational flexibility.
2. Smaller utilities have fewer financing options, less institutional interest in acquiring their debt securities, issued debt would be relatively illiquid, and, if issued to third-parties would likely require stricter covenants than debt issued by large utilities.

Ms. McShane also points out that debt rating agencies often take size into account when rating companies and their debt issues. The impact of smaller size for rated utilities is frequently exhibited in lower debt ratings for these companies even in cases where their financial parameters are stronger than their larger peers. (Exhibit B1-9, Appendix F, p. 134)

PNG submits “there was little to no evidence submitted that suggested or countered that size was not a significant factor.” While precedents and empirical studies exhibit a broad range of explicit company size adjustments (150-436 bps), which introduces a degree of subjectivity, PNG further submits that “Stage 1 evidence concerning size as an independent factor was relatively uncontested.” (PNG Final Submission, p. 13)

7.2.2 Stand-Alone Principle

Both Ms. Ahern and Ms. McShane reaffirm the importance of the stand-alone principle, which is “a cornerstone of Canadian utility regulation with a history dating to at least 1978.” (Exhibit B1-9, Appendix F, p. 10, B2-9, BCUC 1.4.7) Therefore, even if a small utility is owned by a larger parent company, there should be no impact on the determination of the small size utility ROE and capital structure. Each utility within the Commission’s jurisdiction should be evaluated on a stand-alone basis.

Ms. Ahern further states there is ample academic evidence that investors demand greater returns to compensate for the lack of marketability and liquidity of the securities of smaller firms. She submits “it is the use of funds invested and not the source of those funds which gives rise to the risk of any investment.” She refers to the text of Brealey and Myers, which notes “Each project should be evaluated at its own opportunity cost of capital; the true cost of capital depends on the use to which the capital is put.” (Exhibit B2-7, p. 7)

7.2.3 Academic Evidence of the Size Effect in Literature

In her filed evidence, Ms. Ahern provides additional examples of the academic literature, where the risk effects of a company’s size on the investor required return is addressed:

Eugene F. Brigham, *Fundamentals of Financial Management:*

> A number of researchers have observed that portfolios of small-firms have earned consistently higher average returns than those of large-firms stocks; this is called “small-firm effect.” On the surface, it would seem to be advantageous to the small firms to provide average returns in a stock market that are higher than those of larger firms. In reality, it is bad news for the small firm; what the small-

> firm effect means is that the capital market demands higher returns on stocks of small firms than on otherwise similar stocks of large firms.
>
> (Exhibit B2-7, PMA-3, p. 4)

Giacchino and Lesser, *Principles of Utility Corporate Finance:*

> In general, smaller firms face greater financial risk than do large firms... Generally, firm size is measured in terms of total capitalization (i.e., the market value of a firm's equity). Empirical studies have typically found that small firms typically have higher returns over the long run than larger firms. (Exhibit B2-7, PMA-4, p. 3)

Fama and French, in *"The Capital Asset Pricing Model: Theory and Evidence,"* *Journal of Economic Perspectives*, note that size is a risk factor which must be reflected when estimating the ROE:

> ...the higher average returns on small stocks and high book-to-market stocks reflect unidentified state variables that produce undiversifiable risks (covariances) in returns not captured in the market returns and are priced separately from market betas. (Exhibit B2-7, PMA-5, p. 14)

Based upon this evidence, Fama and French proposed their three-factor model which includes a size variable in recognition of the effect of size on the rate of return on common equity.

Marc Reinganum, *"A Possible Explanation of the Small Firm Effect,"* *The Journal of Finance:*

> While the OLS estimates seem to understate the betas of small firms, the excess returns not explained by the misestimation could easily exceed twenty percent per year on average. Thus, one can conclude with confidence that the small firm effect is still a significant economic and empirical anomaly. (Exhibit B2-6, PMA-6, p. 9)

From her academic research, Ms. Ahern concludes that:

- The specific, unique risks of the investment (e.g. utility) must be reflected in the rate of return; and
- The size of an investment (e.g. size of the utility) is one of those unique risk factors for which investors must be compensated. (Exhibit B2-7, pp. 10-11)

7.2.4 Empirical Evidence for the Risk Effects of a Company's Size on the Investor's Required Rate of Return

Studies on small size and returns have quantified the impact of a firm's small size on the required return based on an analysis of the relationship between betas and historical returns for companies of different sizes. Ms. McShane and Ms. Ahern state the analyses indicate that small companies tend to exhibit higher betas than larger companies. Two empirical studies reviewed by Ms. Ahern are:

Morningstar/Ibbotson Size Premium Study (Firm Size and Return)
Ibbotson SBBI – 2012 Valuation Yearbook

This study constructs decile (10) portfolios of the companies contained in the NYSE, AMEX and NASDAQ. Ms. Ahern suggests that the study can be used to determine the approximate risk premium due to size for a specific utility over the benchmark utility return. This is done by comparing the size premium appropriate for the decile in which the benchmark utility would fall based on the estimated market capitalization with the size premium appropriate for the decile in which the specific utility would fall based on market capitalization.

	Decile	**Market Capitalization ($Millions)**	**Size Premium (%)**
Benchmark Utility	5	2,246 (average)	1.74
Micro-Cap	10	92	6.10
Size Premium			**4.36%**

(Exhibit B2-6, PMA-8, Table 7-1 and 7-5)

Duff & Phelps Size Study and Risk Study

The Size Study analyzes the relationship between equity returns and company size in a similar manner as the Morningstar Study. It could also be used to determine the magnitude of any necessary risk premium due to the size of a specific utility relative to the benchmark. In addition to presenting risk premia and size premia for 25 size-ranked portfolios using the traditional market capitalization measure, this study also considers seven other measures of company size, including book value of equity, 5-year average net income, market value of invested capital, total assets, 5-year average EBITDA, sales and number of employees. (Exhibit B2-7, PMA-9, p. 30)

The Risk Study is an extension of the Size Study. The main difference is that while the Size Study analyzes the relationship between size and return, the Risk Study analyzes the relationship between fundamental risk measures (based on accounting data) and return. These are called "fundamental" measures of a company risk to distinguish these risk measures from a stock market-based measure of equity risk such as betas. (Exhibit B2-7, PMA-9, p. 65)

Corix provided a calculation of the size risk premium for micro utilities over the benchmark based on the Duff & Phelps Study. This resulted in a 3.89 percent risk premium as opposed to the 4.36 percent size premium based on the Morningstar Study. (Exhibit B2-8, Attachment to BCPSO 1.1)

7.2.5 Regulatory Support for Size Premium

Ms. Ahern provided only one example of a jurisdiction which has adopted the size premium concept. She cites the Florida Public Service Commission (FL PUC), which adds for small water utilities a bond yield differential, a 50 bps private placement premium and a 50 bps small utility risk premium to the ROE based upon the index of natural gas utilities. Regardless, Ms. Ahern recommends that the size risk of each utility be measured in accordance with the Morningstar/Ibbotson and the Duff & Phelps studies. Specifically, Ms. Ahern states "all of these risk premium spreads should then be averaged and through the exercise of informed expert judgement, a determination of the appropriate risk premium to be added to the benchmark utility return on equity to reflect the size risk of the utility/project relative to the benchmark utility." (Exhibit B2-9, BCUC 1.12.1; Exhibit B2-8, BCPSO 1.2.1)

In responses to IRs and during cross-examination, Ms. Ahern made it clear that she is not recommending any particular amount of a size premium to be adopted by the BCUC but is simply providing testimony for the purpose of establishing a framework. (T6:1128) Similarly, Ms. Ahern states the 4.36 percent risk premium shown in the example would only represent the upper limit of a size premium above the allowed benchmark ROE due to small size. Where in the 10th decile, Corix or any of its projects fall needs to be evaluated to determine the exact risk premium it would propose. Corix stated it has not yet undertaken a comprehensive study of the appropriate size risk premium above the benchmark for each of its projects and indicated that such a study will be conducted in the next phase of the GCOC proceeding. (Exhibit B2-9, BCUC 1.13.2)

Ms. Ahern acknowledged that based on her experience the regulatory support for a specific size premium has been minimal and that ultimately any risk premium, whether it is linked to business risk in general or size specifically, is a matter of informed expert judgment. (T7:1278-1284) Further, Ms. Ahern could provide only seven cases out of over 200 regulatory proceedings where she has been involved that resulted in an allowed size adjustment. Yet, in a response to an undertaking, it appears that only two of those seven cases *specifically* reference “size” in the determination of the overall ROE and only one case granted a specific size premium. (Exhibit B2-14) Furthermore, the Panel notes that Ms. Ahern had recommended only modest size adjustments in the range of 25-50 bps in all those seven cases.

Ms. McShane concludes the empirical study findings indicate that small size is a factor that both debt and equity investors are concerned with, and which should be taken into account when evaluating ROEs and capital structures of individual utilities in British Columbia. (Exhibit B1-9, Appendix F, p. 136)

Commission Determination

<u>Stand-Alone Principle</u>

The Panel reaffirms the long history and importance of the stand-alone principle in Canadian utility regulation. The determinations on the benchmark ROE and capital structure in this Decision are based on this principle. Therefore, there is no reason to deviate from this principle even in the case of small utilities or projects whether or not they are part of a larger utility. These projects can represent either a “new” utility with a greenfield operation and no historical performance data or an existing facility being developed into a TES project. Each project needs to be considered individually and independently.

The Size Premium

The Panel has considered the evidence on record regarding the academic literature on the size effect as well as the empirical evidence for the risk effects of a company's size on the required rate of return. Noteworthy is the lack of regulatory support for the recognition of a small size risk premium. Finally, the Panel notes the requirement for on-going exercise of informed judgment by both the Commission and experts retained by the utilities, which was acknowledged by Ms. Ahern.

As a result, the Panel recognizes the academic literature and empirical studies seem to support the importance of size in explaining returns. At the same time, however, the evidence presented does not indicate how adjustment for size should be implemented.

Accordingly, the Panel determines that the small size factor should be further considered in the Stage 2 proceeding, but only as one of the many business and financial risks small utilities or projects are exposed to. Utilities are encouraged to use other methodologies or approaches to justify their risk differential in relation to the benchmark. The Panel has not been sufficiently persuaded to put any weight to the empirical studies reviewed to date.

The Panel notes that the Commission developed a risk matrix that has been used in various small TES utilities proceedings to evaluate overall risk of a given project. The "size" factor is one of the risk factors included in the matrix. **The Panel recommends that the small utilities use this risk matrix attached as Appendix B to Order C-1-13 of the TELUS Garden Decision[9] in the Stage 2 proceeding and for future projects to justify their case for the appropriate capital structure and risk premium over and above the benchmark ROE**. For convenience, the risk matrix is attached in Appendix E of this decision. Small utilities, other than TES, can modify this matrix to facilitate a similar comparison of their own short and long-term risks to those of FEI.

The Panel is cognizant of the on-going Phase 2 of the Alternative Energy Solutions (AES) Inquiry,[10] which involves development of a regulatory framework for dealing with small TES utilities. This evolving process will further influence the nature and content of future TES applications.

9 Certificate of Public Convenience and Necessity Order C-1-13 and Reasons for Decision dated February 5, 2013, regarding FAES Telus Garden Thermal Energy Services

10 In the Matter of FortisBC Energy Inc. Inquiry into the Offering of Products and Services in Alternative Solutions and Other New Initiatives

7.3 Guiding Principles for Setting Deemed Capital Structure and Deemed Debt

7.3.1 Determination of Deemed Capital Structure

The Commission deems an appropriate common equity ratio for the utility. The resultant debt ratio is simply the residual between 100 percent and the deemed equity ratio. However, the deemed component typically incorporates actual debt issues where rates can be objectively observed and determined. In some cases, the utility manages its actual financing to mirror the deemed debt/equity ratio.

Ms. McShane explains the actual debt issues may consist of issues that have been made directly into public markets; they may be private placement to third party institutions such as bank or insurance companies, or they may be non-arms length issues between a utility and affiliated company. In the latter case, there is a contract between the utility issuer (a legal entity) and the affiliated company, which specifies the terms and conditions of the loan, with rates that are based on market conditions. When the parent company issues debt, the subsidiary can enter into an arrangement with the parent for a specific portion of that debt issue, with the same terms as the third-party issue. Alternatively, the utility may enter into an arrangement with its parent for a debt issue that reflects the utility issuer's risk profile, funding requirements and market conditions at the time the issue is made, but is not tied to a specific third-party issue made by the parent. (Exhibit B-1-9-6, McShane Evidence, Appendix F, p. 121)

7.3.2 Criteria for Setting the Deemed Capital Structure

Ms. Ahern, the Corix expert, states that an appropriate deemed capital structure should:

- be reasonable relative to or consistent with the average capital structure of the particular utility industry;
- reflect the specific utility's unique risks, including its relative size;
- be consistent with bond rating agency metrics; and
- provide the opportunity for the utility to earn a reasonable and fair rate of return, given its unique risks, e.g., size etc.

(Exhibit B2-7, p. 19)

Ms. McShane provides general principles that should be observed when setting the ROE and common equity ratio for utilities, regardless of size:

- The combination of ROE and common equity ratio awarded to each utility in relation to the overall return adopted for the benchmark utility should reflect the level of that utility's business risk relative to that of the benchmark utility;
- The overall return awarded to each utility should be comparable, on a risk adjusted basis, to the overall return awarded to the benchmark utility;
- The capital structure, in conjunction with the ROE, should be adequate to permit the utility, on a stand-alone basis, to achieve investment grade debt ratings, with the caveat that some utilities many not actually have a credit rating; and
- There is a trade-off between equity ratio and ROE. For example, if a utility is not fully compensated for higher business risk than that of the benchmark utility through its common equity ratio, its ROE needs to be higher than the ROE granted to the benchmark utility. (Exhibit B1-9-6, p. 129)

7.3.3 When Is Deemed Debt Appropriate?

The FBCU state the deemed debt is appropriate for small utilities in cases where raising debt is inefficient. For example, a separate division or class of service within a larger regulated utility can contain a stand-alone project. Similarly, a regulated utility subsidiary/affiliate within a larger corporate organization can face circumstances where either:

(i) The high cost of debt issuance relative to the size of the issue makes the effective debt cost higher than it would be otherwise; or

(ii) The size of the utility precludes it from accessing appropriate debt terms.

The FBCU further state that the assessment as to whether deemed debt is appropriate and efficient should involve some judgment to ensure that the use of deemed debt is limited to circumstances where it is efficient to do so. Finally, FBCU state "it is reasonably clear that deemed debt would be appropriate for FEW (a separate legal entity), the Fort Nelson Division of FEI, and FAES." (FBCU Final Submission, p. 163; Exhibit B1-20, BCUC 1.140.1, 1.140.2)

7.3.4 Setting the Appropriate Deemed Debt Rate and Term

The FBCU state that deemed debt rates and duration should reflect the particular circumstances of each utility. Utilities for which a deemed cost of debt might be appropriate may have differing profiles; FEW, for instance, is not the same as one of FAES's TES projects or Corix's UniverCity project. The appropriate term of debt may also vary even among projects with a broadly similar risk profile. (FBCU Final Submission, p. 163; Exhibit B1-20, BCUC 1.140.2)

Ms. McShane submits as a general proposition that the term should reflect the long-term nature of the assets and offers the following additional considerations:

1. If the specific utility operations are backed by contractual arrangements, the length of the contract would be a relevant consideration in the determination of the term for the debt.
2. The higher the risk of the specific operation, the less their ability would be to obtain "real" debt on a long-term basis; i.e., on terms longer than 10 years. The term of the debt should reasonably reflect the limitations of what would reasonably be available to operations with a similar risk profile.
3. The appropriate term for the deemed debt also depends on the state of the capital markets.

Ms. McShane concludes that the individual utilities' circumstances may differ in terms of risk, the funding requirements and appropriate terms of debt. Accordingly, she recommends that the Commission continue to address the cost of deemed debt for each utility separately, on a case-by-case basis. In her view, there is no "one size fits all" cost mechanism. (Exhibit B1-9-6, pp. 123-124)

Commission Determination

Before addressing the issue of short-term and long-term debt in the deemed capital structure and the methodology for determining a deemed interest rate, the Commission Panel wishes to reaffirm certain principles for the Stage 2 GCOC proceeding framework.

(i) The general principles and criteria outlined by the Corix and FBCU experts for setting the capital structure for any utility in general and the deemed capital structure specifically for the small utilities are accepted as they are consistent with the principles adopted for setting the benchmark ROE;

(ii) Deemed debt is appropriate for small utilities in cases where raising debt is inefficient;

(iii) Deemed debt rates and duration should reflect the particular circumstances of each utility. Accordingly, the Commission should continue to address the cost of deemed debt for each utility separately on a case-by-case basis; and

(iv) Risk assessment of small utilities, especially the TES projects, must include consideration of rate setting mechanisms, deferral account treatment, length of term and the overall risk/reward equation.

Related to the issue of deemed capital structure and deemed debt are two key questions that the Stage 2 GCOC proceeding must address more comprehensively:

1. Can the combination of the deemed debt/equity ratio and the allowed ROE sufficiently compensate for the unique risks of a particular small utility or project?
2. How important is it to maintain consistency between the risk premium determination and assigning a deemed credit rating for a small utility without third party debt? For instance, would it be reasonable to allow no risk premium over FEI for a TES project while setting the debt rate based on a BBB bond rating?

7.4 Appropriate Portions of Short-Term and Long-Term Debt in the Deemed Capital Structure

In British Columbia, in some of the more recent TES Decisions, the Commission has considered deeming a portion of overall debt to short-term debt. To date no determination has been made to put this into effect. However, the Panel notes that the OEB has officially deemed a standard four percent proportion of short-term debt component for utilities under its jurisdiction for reasons that it outlined in its 2006 Decision:

(i) All utilities actually use some short-term debt;

(ii) Short-term debt is generally less expensive than long-term debt and provides greater financing flexibility; and

(iii) While actual short-term debt percentages may seem to be a more accurate approach, it is administratively challenging given the number of distributors regulated by the OEB.[11]

[11] OEB, Report of the Board on Cost of Capital and 2nd Generation incentive Regulation for Ontario's Electricity Distributors, December 20, 2006, pp. 9-10

In 2009, the OEB reaffirmed this practice for natural gas distributors as well. It also updated its methodology to estimate the deemed short-term debt rate. (Exhibit A2-21, Report of the Board on the Cost of Capital for Ontario Regulated Utilities, EB-2009-0084)

Ms. McShane states there is no single right answer to the question of what proportion of a deemed capital structure should be designated as short-term debt. She notes that annual fluctuations for individual utilities will reflect, among other things, the fact that utilities frequently use short-term debt as a bridge between long-term debt issues. Based on her filed evidence she further states that the average proportion of short-term debt to total capital for rated Canadian utilities has been approximately 1 percent to 2 percent. Her review of 2010 data for Ontario electricity distributors indicated that the average and median actual short-term debt ratios were at 2.9 percent and 0.4 percent respectively. (Exhibit B1-9-6, pp. 125-127)

Ms. Ahern states that conceptually the maturity of the debt capital should match the life of the assets being financed. But when the inclusion of short-term debt is optional, its inclusion should be based upon several criteria:

- If its use is sporadic and hence, volatile, it should not be included in the capital structure. However, if its use is consistent and especially at a significantly high level, it is likely financing rate base and possibly should be included;
- If its use is seasonal and self-liquidating, e.g., financing short-term inventories of natural gas in anticipation of heating season, it probably should not be included;
- If short-term debt is financing working capital, it should be included;
- If it is used as bridge financing until permanent financing can be put in place it should be included at the expected cost rates of that permanent financing; and
- If the short-term debt financing construction projects and if the Construction Work In Progress (CWIP) are included in rate base the short-term debt should be included. (Exhibit B2-7, pp. 23-24)

The FBCU provided information showing actual percentages of short-debt for FEI, FEI – Fort Nelson, FEVI, FEW, and FortisBC Inc. for the 2002-2012 period. While there has been significant fluctuation over the years, the average percentages for the period as a share of capital structure amounted to

5.28 percent, 8.58 percent, 10.77 percent, 13.10 percent and 5.27 percent for each respective utility. (Exhibit B1-24, BCUC 2.189.1, 2.189.2)

Commission Determination

The Commission Panel finds it as an accepted fact that all utilities use some short-term debt financing. The FBCU IR responses clearly support this. While there are varying reasons for its use, the evidence demonstrates that, on average, utilities always carry a small portion of short-term debt in their capital structure. The construction work in progress, due to its nature, is often financed by short-term debt.

Accordingly, the Commission Panel finds it reasonable and prudent to include a deemed component of short-term debt in the capital structure for all small utilities without third-party debt to reflect reality. To establish the percentage of short-term debt to be deemed, the Panel has considered testimony of Ms. McShane, FBCU IR responses and the OEB established practice in Ontario. **While acknowledging that there is no correct amount, the Panel concludes that a four percent component for deemed short-term debt provides a reasonable proxy as it is the midpoint of the range of actual short-term borrowing.**

7.5 Setting the Deemed Interest Rates

7.5.1 <u>Deemed Interest Rate for Long-Term Debt</u>

Parties acknowledge that there are at least three reasonable options for determining the deemed interest rate applicable to a small utility without third-party debt. These options are summarized below.

<u>FBCU Option 1:</u>

Step 1: Assign a credit rating on a stand-alone basis, and then obtain indicative quotes from investment dealers or banks based on the credit rating of a comparable proxy issuer. Using proxy companies that are engaged in the power sector or energy infrastructure can help to minimize subjectivity. The FBCU submit this approach is consistent with the stand-alone principle, and is how FEW has financed the debt component of its capital structure. (Exhibit B1-9, pp. 29-30; Exhibit

B1-20, BCUC 1.141.1, 1.141.5, 1.144.2) A reasonable deemed stand-alone rating for a small regulated utility appears to be in the range of BBB to BBB (low), with the deemed debt cost set on this basis. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 123; Exhibit B1-20, BCUC 1.147.1)

Step 2: Determine a Government of Canada (GoC) bond yield reflecting the proposed term of debt that could be either the 10-year or 30-year bond as the benchmark, or an interpolation of the two. The selected benchmark should reflect the long-term nature of utility assets, contractual terms and available debt terms. (Exhibit B1-9, p. 30)

Step 3: Determine the credit spread of a comparable corporate proxy issuer in similar industries or lines of business (e.g., regulated utility, power generation, energy infrastructure) at the same term to maturity as that selected as the benchmark GoC bond. (Exhibit B1-9, p. 30; Exhibit B1-24, BCUC 1.141.5.2; Exhibit B1-24, BCUC 2.188.2, 2188.3)

<u>FBCU Option 2</u>:

Ms. McShane identified an alternative approach to use the embedded cost of debt of the issuing entity as the deemed interest rate and allocate the deemed debt and interest rate based on an approved capital structure. Currently, FEI-Fort Nelson debt is deemed and the rate is the embedded cost of debt. (Exhibit B1-20, BCUC 1.141.1, 1.141.6) The FBCU submit that this is an administratively efficient way to allocate debt issued by a single regulated entity, allows the benefits of issuing all debt centrally to be shared, and provides a reasonable degree of assurance that the regulated entity raising the debt will be able to recover its actual incurred cost of debt. (Exhibit B1-20, BCUC 1.148.8)

<u>Corix Option</u>:

Corix supports FBCU's recommendation to apply one benchmark credit spread for small utilities to provide regulatory efficiency. To align with the proposed method, the benchmark credit spread would reflect the spread for BBB and BBB (low) rated debt relative to the underlying 10 year GoC bond yield and would reflect incremental risk of small utilities. Corix states that with the benchmark set for small projects, project stakeholders and interveners can then justify any variances from the benchmark depending on the risk exposure. (Exhibit B2-9, BCUC 1.26.3, 1.27.1, 1.46.5, 1.46.7, 1.46.11)

<u>Commission Staff Option</u>:

This option was raised in order to account for the scarcity of BBB-rated utilities in Canada that can be used as proxy, and for the possibility that utility ratings can be changed.

Step 1: Obtain the yield on an appropriate GoC bond as the benchmark.

Step 2: Assign a credit rating to the stand-alone utility/project based on an assessment of financial and business risk (e.g., BBB, other)

Step 3: Obtain the bond yield (credit) spread between GoC bond and a high grade utility (A or A low) and add it to the rate in Step 1.

Step 4 Add a premium, if required, to the credit spread in Step 3. This premium will be calculated as the credit spread between high grade utility bonds (A or A low) and utility bonds of the credit rating estimated in Step 2. The use of historical data (e.g., two most recent years) to have more data points could be considered. (Exhibit A2-43; Exhibit B1-20, BCUC 1.141.9; Exhibit B1-24, 2.188.6; Exhibit B2-9, BCUC 1.26.6)

The FBCU submits it is generally supportive of the Staff option but raised one concern. Ms. McShane cautioned that for any method involving the use of credit rating proxy companies, care should be taken to employ reasonable credit ratings. She re-emphasized that an appropriate credit for small utilities would be BBB to BBB (low), as the inherent risk of small size would preclude them from achieving higher ratings:. "As it is much more likely that the small utility would be BBB on a standalone basis, it makes sense to use a BBB yield as the benchmark to begin with rather than using A-rated proxies." (FBCU Final Submission, pp. 164-165; T5: 680-681)

Commission Determination

The evidence and Final Submissions suggest that setting the deemed interest rate is not a very controversial issue. However, each option reviewed has advantages and disadvantages. The Panel also notes that similar approaches have been adopted in number of recent TES Decisions. For example, BBB-rated proxies were used for the Delta School District Number 37 and Tsawwassen Springs projects.

The Commission Panel has already found that the cost of deemed long-term debt (rate and term) for each utility should be addressed separately on a case-by-case basis. Based on this the Panel recommends that on a go-forward basis the FBCU's Option 1 be used as a guideline for setting the deemed debt rate. The Panel is cognizant of the refinement proposed by Commission Staff to account for the scarcity of BBB-rated utilities in Canada that can be used as a proxy. Should this become a major issue in the future, the Commission can consider switching to use the Commission Staff Option as the guideline.

Because the deemed long-term debt by definition is set for a fixed term, the Panel finds that adjustments will not be necessary during the term of the loan. The only reason for a re-opener would be the situation where a small utility actually issues new debt. The impact of the rate change could be considered a subsequent revenue requirement review.

However, to allow some flexibility, the utilities will have an option to apply for a rate adjustment in accordance with the following reopener-criteria:

- **A measurable change in market conditions**
- **A measurable change in actual debt costs**

The Commission will consider each application for a rate adjustment on a case-by-case basis.

7.5.2 Deemed Interest Rate for Short-Term Debt

The FBCU state the basis for determining the deemed interest rate for short-term debt would be similar to that of long-term interest rate determination. It would be based on indicative credit spread quotes from investment dealers or banks using comparable proxy issuers plus a short-term benchmark yield. A common benchmark yield in Canada is the Canadian Dealer Offered Rate (CDOR). CDOR is the quoted benchmark that is used when a company issues short-term Bankers' Acceptances (BAs), which reflect the short-term benchmark rate plus the company's applicable credit spread. (Exhibit B1-9, p. 31) In response to IRs, the FBCU clarified that quotes from banks would be obtained based on indicated credit rating, not by individual proxy issuer. (Exhibit B-20, BCUC 1.44.2, 1.44.3)

Ms. McShane states that three-month BAs are also a common benchmark for establishing the cost of short-term debt for utilities. (Exhibit B1-9-6, McShane Evidence, Appendix F, pp. 127-128) In response to IRs the FBCU confirm that either the 3-month CDOR or 3-month BA rate is reasonable for setting the short-term rate. Regarding the indicative credit spread quotes, the FBCU state the following approach used by the OEB is reasonable: the OEB obtains up to six quotes from banks. If it obtains six quotes, it discards the highest and the lowest and uses the average of the remaining four. If less than four are obtained, it uses the average of all the quotes obtained. (Exhibit B1-20, BCUC 1.144.4) The FBCU submit that the OEB formulaic approach is an efficient and transparent way of estimating a deemed short-term debt rate. However, the FBCU stress that the OEB methodology is premised on a single debt rating, a short-term debt rating of R1-low, which generally corresponds to long-term credit ratings in the A category; i.e., higher than would be applicable to the small utilities. To overcome this problem, the FBCU suggest using a more reasonable short-term credit rating, one that would correspond to a BBB/BBB (low) on the long-term rating scale. (Exhibit B1-20, BCUC 1.144.5, 1.144.5.1)

Commission Determination

The Commission Panel recommends that small utilities use either the 3-month CDOR or 3-month BA rate as a basis and obtain 3-4 quotes to establish the credit spread for the purpose of setting the deemed short-term interest rate. Because it is highly unlikely that small utilities, especially the TES utilities/projects, will have frequent revenue requirement reviews, the Panel finds that there is no requirement for an annual adjustment mechanism. **The short-term rates are to be reset at the time of the revenue requirement review only.**

8.0 OTHER MATTERS

8.1 Reliance on Less Complex Financial Methodology

Expert witnesses in this proceeding expressed reluctance to use more complex models that could improve understanding and/or estimating the cost of equity. For instance, Ms. McShane states: "I think it's reasonable to try to capture these other factors. I know that it's been difficult to have regulators accept the Fama/French type models ..." (T5:721)

In response to a question from Commissioner Giammarino, Dr. Vander Weide expressed similar concerns:

> **COMMISSIONER GIAMMARINO:** "And [Fama/French] suggest that maybe the future is in an inter-tempo CAPM, that has multi factors. And that would allow for changes in the opportunities – the investments that are available to investors. Did you consider that as an alternative?" (T6:1103)
>
> **DR. VANDER WEIDE:** "That would certainly be an alternative, but from my years in testifying on the cost of capital, I have realized that there are two qualities that make a model present reasonable evidence. One is that it's -- you can estimate the inputs to the model reasonably well, and two, it has to be reasonably easy to understand. So that one can judge the model in the context where everyone doesn't have Ph.D.s in finance or economics. And once you get into dynamic capital asset pricing models, to me that's getting into a level that's too complicated for discussion in a public forum." (T6:1103)

Although Dr. Booth added a credit spread adjustment to his CAPM analysis, he also expressed a similar sentiment about adding further factors to his CAPM, as shown by the following exchange:

> **COMMISSIONER GIAMMARINO**: …there is sort of a well-established set of suspects. You've looked at one.
>
> **DR. BOOTH:** Correct.
>
> **COMMISSIONER GIAMMARINO:** So why not look at all?
>
> **DR. BOOTH:** Two reasons. First of all, with all due respect to the Commission, it's a question of getting things to the Commission in an understandable way through cross-examination. And KISS works. That a simple way of looking at these things, I think, makes sense. The only time,

> for example, I saw a company put forward the Fama French model was before the Gaz Métro. And the witness had a real tough time with the more complicated model. And the Régie was very reluctant to adopt a more complicated model.
>
> **COMMISSIONER GIAMMARINO:** Right.
>
> **DR. BOOTH:** So when you get down to conditioning, you're absolutely correct. You think about Chandrell and Ross, and you think about economic factors affecting security returns, you can go to more measures. Does the addition of more measures make the testimony more saleable to a Commission? And the answer to that is generally no. It may make it more saleable in an academic seminar but it's easier, I think, to pick on one thing that people can relate to – credit spreads – that was picked up in most of the hearings in 2009, which seems to make sense, and seems to be consistent with the academic literature, than to go through a more complicated model with term structure, yield parameters, dividend yields or other conditioning variables. So, I pick one, the credit spread. (T8:1658-59)

The Commission Panel accepts that evidence should meet some basic criteria. For example, expert witnesses must have confidence in their estimates; and the evidence must be understandable to the Panel, ideally for all parties involved. The Panel is, however, concerned that experts pay undue attention to prior assessments of the limits of what the Commission will understand and/or accept. While evidence put forward should be as helpful as possible to a Panel dealing with the difficult task of determining the appropriate rate of return and capital structure, it should reflect the expert's best judgment about the state-of–the-art methodology, which should in turn be presented in an understandable way.

It is the Commission Panel's opinion that the purpose of a cost of equity model is to provide structure to the discussion of 'what is a fair rate of return.' Models used to fulfill this purpose provide structure and clarity, and in turn provide a basis for determining the truth of any particular assessment. Models are abstractions and, by definition, imperfect representations. As a result, it is up to the Panel to decide how much confidence it should put in various models that have unrealistic assumptions and do not explain returns perfectly. The Panel must also understand where judgment needs to be applied to the output delivered by these models.

Specifically, in Section 5.2.1, the Panel identified some of the weaknesses related to the adjustments to the CAPM. In particular, the experts expressed reluctance to include additional potential extensions to the CAPM because they were perhaps "too complex" to the Panel. This in turn leaves open what results other extensions could imply. Similarly, in the beginning of Section 5.2 the Panel identified the lack of global perspective in assessing the investor's portfolio. A more clear set of principles, including a definition of FEI's investors' portfolios (i.e., Global, North American, Canadian) would have been valuable. Accordingly, the Panel invites more comprehensive evidence on these topics in the future.

The Commission Panel believes that one of the roles of the expert is to guide the regulator in evaluating the trade-off between the complexities of the structures needed to evaluate arguments versus the reliability of the structures. This trade-off is at the heart of cost of capital hearings. As this trade-off evolves constantly, the testimony should evolve with it.

8.2 FEI - The Benchmark Utility

Based on the evidence related to long and short-term risk before the Commission Panel we are in agreement with describing FEI as the "benchmark utility" rather than a "low-risk benchmark utility." While the Panel has determined that the level of risk is somewhat less in a number of areas than those which existed at the time of the 2009 Decision, there has been little change in many areas. Therefore, we are of the view that describing FEI as low-risk would not be appropriate. Accordingly, for the purposes of Stage 2 of the GCOC, FEI will be referred to as the benchmark utility. **The common equity component and the approved ROE in this Decision will serve as the benchmark cost of capital for any other utility in British Columbia that uses the benchmark utility to set rates.**

The issue as to whether FEI is a pure-play gas distribution received little direct attention beyond the October 4, 2012 procedural conference. However, the Commission Panel has considered the issue in the context of the level of throughput related to alternative energy initiatives. It appears that FEI's forecasted throughput related to alternative energy initiatives is relatively small. Under cross-examination, FBCU witness, Mr. Stout with reference to natural gas transportation initiatives stated:

> "...we forecast two and a half to three petajoules in 2017. I think even if you go to some volume that's in the 10 to 15 petajoule range, it's still less than 10 percent of the throughput of the system, say 5 to 10 percent of the total throughput". (T3:317)

Based on Mr. Stout's testimony, the Commission Panel accepts that FEI at this point in time is primarily a pure-play gas distribution utility.

While Stage 1 of the GCOC proceeding has been mainly concerned with determining an appropriate cost of capital for the benchmark utility, Stage 2 will be primarily concerned with business risk assessment relative to the benchmark. More specifically, public utilities will be called upon to provide evidence as to how they differ from FEI with respect to business risk. The Commission Panel considers that it is feasible that a stand-alone public utility may face overall business risks that are either higher, lower or the same as the benchmark utility.

The primary factors that have influenced FEI's long-term risk have been identified and addressed in Section 4.2. In addition, we have further identified and made determinations upon FEI's short-term risk. In Stage 2 of the GCOC, the public utilities, where appropriate, will be required to describe how they differ from the benchmark utility on these and any other risk factor as it relates to them. In addition, in Section 7.2.5 the Commission Panel has described a risk matrix (included in Appendix E) as a tool for the small utilities (especially the TES utilities) to further assist in justifying their case for an appropriate capital structure and risk premium.

DATED at the City of Vancouver, in the Province of British Columbia, this 10th day of May 2013.

Original signed by:

____
D.A. COTE
PANEL CHAIR/COMMISSIONER

Original signed by:

____
R. GIAMMARINO
COMMISSIONER

Original signed by:

____
M.R. HARLE
COMMISSIONER

Original signed by:

____
L.A. O'HARA
COMMISSIONER

**BRITISH COLUMBIA
UTILITIES COMMISSION**

**ORDER
NUMBER** G-75-13

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Generic Cost of Capital Proceeding

BEFORE: D.A. Cote, Commissioner/Panel Chair
M.R. Harle, Commissioner
L.A. O'Hara, Commissioner
R. Giammarino, Commissioner

May 10, 2013

O R D E R

WHEREAS:

A. By Order G-20-12 dated February 28, 2012, the British Columbia Utilities Commission (Commission) established a Generic Cost of Capital (GCOC) proceeding to review: (a) the setting of the appropriate cost of capital for a benchmark low-risk utility; (b) the possible return to a Return on Equity Automatic Adjustment Mechanism (ROE AAM) for setting an ROE for the benchmark low-risk utility; and (c) the establishment of a deemed capital structure and deemed cost of capital methodology, particularly for those utilities without third party debt;

B. Appendix C to Order G-20-12 divided public utilities into two categories for the purpose of the proceeding: "Affected Utilities" and "Other Utilities;"

C. FortisBC Energy Inc. (FEI), FortisBC Energy (Vancouver Island) Inc., FortisBC Energy (Whistler) Inc. and FortisBC Inc. (FortisBC)[collectively (FBCU)]; Corix Multi-Utility Services Inc. (Corix); and Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd. (PNG) registered as Affected Utilities. The British Columbia Hydro and Power Authority (BC Hydro) and the River District Energy (RDE) registered as Other Utilities;

D. Among the Interveners who registered for the proceeding, the Association of Major Consumers of BC (AMPC), British Columbia Pensioners' and Seniors' Organization (BCPSO), Commercial Energy Consumers (CEC) [collectively B.C. Utility Customers], and the Industrial Customers Group of FortisBC Inc. (ICG) actively participated;

E. By Order G-47-12 dated April 18, 2012, the Commission issued the Final Scoping Document for the proceeding. The Scoping Document sets out the purpose and the scope of the proceeding. Matters within the scope of the proceeding included, among others, the appropriate cost of capital and its effective date for a benchmark low-risk utility, the establishment of a benchmark ROE, the consideration of an automatic adjustment mechanism, and the deemed capital structure and deemed cost of capital for small utilities without third-party debt;

…/2

F. By Order G-50-12 dated April 19, 2012, the Commission, among other matters, set out the further procedural matters to be addressed in the proceeding and a Preliminary Minimum Filing Requirements (MFR) for Affected Utilities document. Parties were invited to make submissions on the Preliminary MFR for Affected Utilities by May 3, 2012, and on the allocation of Participant Assistance/Cost Awards (PACA), PACA eligibility, and/or the Draft Preliminary Regulatory Timetable by May 9, 2012;

G. By Order G-72-12 dated June 1, 2012, the Commission, among other matters, issued the Final Minimum Filing Requirements for Affected Utilities and the Preliminary Regulatory Timetable for the proceeding;

H. On June 8, 2012, the Commission released "A Survey of Cost of Capital Practices in Canada" prepared by The Brattle Group for the Commission (Brattle Report). Utilities and Interveners were provided with the opportunity to ask Information Requests on the Brattle Report;

I. By Order G-84-12 dated June 20, 2012, the Commission amended the Preliminary Regulatory Timetable, establishing, among other things, a Procedural Conference for October 2, 2012 and the commencement date for an oral hearing, if required, on December 12, 2012. The Procedural Conference was subsequently rescheduled to October 4, 2012;

J. At the Procedural Conference the Commission received, among others, submissions on the following items: (1) the appropriate benchmark utility for the determination of the generic cost of capital; (2) whether a Stage 2 for the purpose of determining an appropriate cost of capital for Affected and Other Utilities to immediately follow Stage 1 was desirable; (3) whether an oral phase was required and (4) the proposed timetable going forward;

K. By Order G-148-12 dated October 11, 2012, the Commission determined that : (1) FEI in its present pre-amalgamation state, would serve as the benchmark for the proceeding and whether FEI in 2012 is a pure play gas distribution utility would be determined following the hearing of further evidence; (2) a Stage 2 would be added to the proceeding with the schedule to be determined prior to the end of Stage 1; and (3) the review of the proceeding would continue by way of an oral hearing commencing on December 12, 2012;

L. By Order G-187-12 dated December 10, 2012, the Commission ordered that: (1) the current ROE and capital structure for FEI, the designated benchmark utility, and all regulated entities in B.C. that rely on the benchmark utility, except British Columbia Hydro and Power Authority, are to be maintained and made interim, effective January 1, 2013; and (2) any determinations of the premiums on the benchmark ROE and capital structure of regulated utilities that depend on the benchmark utility for rate setting will be made following the decision in Stage 2; M. The oral public hearing took place over a period of seven days between December 12, 2012 and December 21, 2012. A total of eight witness panels from FBCU and Interveners gave evidence;

N. FBCU, PNG, Corix, AMPC/CEC, ICG and BCPSO filed Final Submissions. FBCU filed a Reply Submission; and

O. The Commission has considered the evidence and the submissions of the Parties all as set forth in the Decision issued concurrently with this Order.

NOW THEREFORE, the Commission orders as follows:

1. The common equity component appropriate for the benchmark utility, FEI, effective January 1, 2013 is 38.5 percent.

2. A Return on Equity (ROE) for the benchmark utility, FEI, is established at 8.75 percent effective January 1, 2013.

3. An Automatic Adjustment Mechanism (AAM) formula for annually setting the ROE of the benchmark utility between ROE proceedings is adopted commencing January 1, 2014. The AAM formula will operate until December 31, 2015. The implementation of the model will be subject to conditions outlined in the Decision.

4. FEI is directed to file an application for the review of the common equity component and the ROE approved in Paragraphs 1 and 2 of this Order by no later than November 30, 2015.

5. The common equity component and the ROE approved in Paragraphs 1 and 2 of this Order will continue to serve as the Benchmark cost of capital for any other utility in British Columbia that uses a Benchmark Utility to set rates.

6. Within 30 days of the date of this Order, FEI is to file:

   (a) a document setting out how and when it will implement the change to its capital structure;

   (b) amended rate schedules in accordance with paragraphs 1 and 2 of this Order as well as a proposal on the treatment of the refundable portion of the rates collected since January 1, 2013.

7. Small utilities without third-party debt are to include a deemed component of short-term debt of 4 percent.

DATED at the City of Vancouver, in the Province of British Columbia, this 10th day of May 2013.

BY ORDER

Original signed by:

D.A. Cote
Commissioner/Panel Chair

LIST OF PROCEDURAL ORDERS

Exhibit Number	Commission Order (Date)	Determinations
A-1	G-20-12 (Feb 28, 2012)	• Stated purpose in establishing the GCOC proceeding • All regulated utilities determined to be applicants in this proceeding. Utilities are divided into "Affected Utilities" and "Other Utilities." • Issued initial regulatory timetable for registration of Utilities and Interveners and written submissions on the Preliminary Scoping Document
A-3	G-47-12 (April 18, 2012)	• Issued Final Scoping Document
A-5	G-50-12 (April 19, 2012)	• Issued preliminary Minimum Filing Requirements (MFR) • Issued preliminary regulatory timetable for written submissions on the MFR and the cost allocation of Participant Assistance/Cost Awards (PACA) and PACA eligibility
A-6	G-72-12 (June 1, 2012)	• Issued Final MFR • Determined the principles in the allocation of PACA costs and PACA cost eligibility • Considered expansion of the current proceeding by conducting the GCOC proceeding in two stages • Issued preliminary regulatory timetable for a Procedural Conference and Stage 1 of the GCOC proceeding. • Put on the record the terms of reference for the survey Report carried out by The Brattle Group
A-9	Order G-84-12 (June 20, 2012)	• Issued amended preliminary regulatory timetable

LIST OF PROCEDURAL ORDERS

Exhibit Number	Commission Order (Date)	Determinations
A-16 and A-17	Letter L-52-12 (September 13, 2012)	• Established the amended date and agenda for the Procedural Conference
A-22	G-148-12 (October 11, 2012)	• Determined that FEI in 2012 in its pre-amalgamation state, will serve as the benchmark utility for the GCOC proceeding • Determined that a Stage 2 will be added to the proceeding • Determined that review will take place by an oral hearing commencing on December 12, 2012
A-30	G-187-12 (December 10, 2012)	• Issued Interim Order establishing current ROE and capital structure for the benchmark utility and all regulated entities in B.C. that rely on the benchmark utility as interim, effective January 1, 2013

LIST OF APPEARANCES

G. Fulton, Q.C.	Commission Counsel
L. Bussoli	Commission Counsel
M. Ghikas	FortisBC Utilities
T. Ahmed	FortisBC Utilities
M. Cheesman	Corix Multi-Utility Services Inc. (Corix)
J. Kennedy	Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd.
R.B. Wallace, Q.C.	Association of Major Power Customers of B.C. (AMPC)
R. Hobbs	Industrial Customers Group of FortisBC Inc. (ICG)
L. Worth	British Columbia Pensioners' and Seniors' Organization (BCPSO)
E. Kung	British Columbia Pensioners' and Seniors' Organization (BCPSO)
T. Braithwaite	British Columbia Pensioners' and Seniors' Organization (BCPSO)
C. Weafer	Commercial Energy Consumers of British Columbia (CEC)
D. Craig	Commercial Energy Consumers of British Columbia (CEC)
J. Christian	British Columbia Hydro and Power Authority (BC Hydro)
B. Hobkirk	British Columbia Hydro and Power Authority (BC Hydro)
R. Hanson	River District Energy
J. Quail	Canadian Office and Professional employees' Union Local 378

E. Cheng Y. Domingo J. Tran B. Grant J. Fraser	Commission Staff
Allwest Reporting Ltd.	Court Reporters

LIST OF PANELS

FORTISBC INC., FORTISBC ENERGY INC., FORTISBC ENERGY (VANCOUVER ISLAND) INC., AND FORTISBC ENERGY (WHISTLER) INC.

PANEL 1 - COMPANY EVIDENCE

Roger A. Dall'Antonia	Vice President, Strategic Planning, Corporate Development and Regulatory Affairs (Panel Chair)
Douglas Stout	Vice President, Energy Solutions and External Relations
Cynthia Des Brisay	Vice President, Energy Supply and Resource Development
Michele Leeners	Vice President, Finance and CFO

PANEL 2 - EXPERT OPINION ON A BENCHMARK FAIR RETURN

Kathleen C. McShane, MBA, CFA	President Foster Associates, Inc.

PANEL 3 - EXPERT OPINION ON AUTOMATIC ADJUSTMENT MECHANISMS

James M. Coyne	Concentric Advisors

PANEL 4 - EXPERT OPINION ON CAPITAL MARKETS

Aaron M. Engen	Managing Director BMO Capital Markets (Energy Infrastructure Group)

PANEL 5 - EXPERT OPINION ON A BENCHMARK FAIR RETURN

James H. Vander Weide, PhD	Duke University

CORIX MULTI-UTILITY SERVICES INC. (CORIX)

Pauline M. Ahern, MBA	Principal AUS Consultants

LIST OF PANELS

THE INDUSTRIAL CUSTOMERS GROUP OF FORTISBC INC. (ICG)

Andrew Safir, PhD	President Recon Research Corporation

THE ASSOCIATION OF MAJOR POWER CUSTOMERS (AMPC), THE COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (CEC), THE BRITISH COLUMBIA PENSIONERS' AND SENIORS' ORGANIZATION (BCPSO), COLLECTIVELY THE BC UTILITY CUSTOMERS

Laurence D. Booth, DBA	University of Toronto

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

British Columbia Utilities Commission
Generic Cost of Capital Proceeding (GCOC) Stage 1

EXHIBIT LIST

Exhibit No.	**Description**
COMMISSION DOCUMENTS	
A-1	Letter Dated February 28, 2012 and Order G-20-12 – Establishing an initial Regulatory Timetable
A-2	Letter Dated April 17, 2012 – Response clarifying Union Gas's Intervener Status
A-3	Letter dated April 18, 2012 and Order G-47-2012 – Reasons for Decision and Final Scoping Document
A-4	Letter dated April 18, 2012 – Appointment of Panel
A-5	Letter dated April 19, 2012 - Order G-50-12 List of Further Procedural Matters
A-6	Letter dated June 1, 2012 - Order G-72-12 Issuing Preliminary Timetable, PACA costs, Final Minimum Filing Requirements for Affected Utilities
A-7	Letter dated June 6, 2012 - Request for Variance of Regulatory Timetable Order G-72-12
A-8	Letter dated June 8, 2012 – Commission Consultant's Survey Report
A-9	Letter dated June 20, 2012 – Order G-84-12 - Amended Preliminary Regulatory Timetable
A-10	Letter dated July 27, 2012 – Request for Comments on the Addition of a Panel Member
A-11	Letter dated August 22, 2012 – Appointment of Commissioner Mr. R. Giammarino
A-12	Letter dated August 31, 2012 – Information Request No. 1 to FortisBC Utilities
A-13	**CONFIDENTIAL** Letter dated August 31, 2012 – CONFIDENTIAL Information Request No. 1 to FortisBC Utilities
A-14	Letter dated August 31, 2012 – Information Request No. 1 to PNG

Exhibit No.	Description
A-15	Letter dated August 31, 2012 – Information Request No. 1 to Corix
A-16	Letter dated September 13, 2012 – L-52-12 Amending Regulatory Timetable
A-17	Letter dated September 27, 2012 – Agenda for Procedural Conference
A-18	Letter dated October 9, 2012 – Information Request No. 2 to FortisBC Utilities
A-19	**CONFIDENTIAL** Letter dated October 9, 2012 – CONFIDENTIAL Information Request No. 2 to FortisBC Utilities
A-20	Letter dated October 9, 2012 –Information Request No. 2 to Corix
A-21	Letter dated October 11, 2012 – Order G-148-12 and Reasons for Decision
A-22	Letter dated October 24, 2012 - Request to Access Confidential Material
A-23	Letter dated October 31, 2012 - Access to Confidential Material Response
A-24	Letter dated November 1, 2012 – Confidential Material Access to AMPC (Exhibit C6-11)
A-25	Letter dated November 16, 2012– Information Request No. 1 to ICG on Intervener Evidence
A-26	Letter dated November 16, 2012– Information Request No. 1 to AMPC on Intervener Evidence
A-27	Letter dated November 20, 2012 – Request for submissions
A-28	Letter dated December 3, 2012 – Oral Public Hearing Information
A-29	Letter dated December 5, 2012 – Opening Statements Clarification
A-30	Letter dated December 10, 2012 - Commission Order G-187-12 establishing the current ROE and capital structure
A-31	Letter dated February 14, 2013 – Commission Response to request for extension

Exhibit No.	**Description**
COMMISSION STAFF DOCUMENTS	
A2-1	Letter Dated February 28, 2012 - Commission Staff Filing British Columbia Utilities Commission letter dated November 28, 2011-Preliminary Notification of Initiation of Generic Cost of Capital Proceeding
A2-2	Letter Dated February 28, 2012 - Commission Staff Filing the Terasen Utilities (December 8, 2010) – Automatic Adjustment Mechanism Review
A2-3	Letter dated June 8, 2012 – Commission Staff Filing the Brattle Group Survey of Cost of Capital Practices in Canada
A2-4	Letter dated July 12, 2012 - Commission Staff Filing Response to AMPC Information Request to Commission Consultants
A2-5	Letter dated July 12, 2012 - Commission Staff Filing Response to FEU Information Request on the Consultants Survey Report
A2-6	Letter dated July 12, 2012 - Commission Staff Filing Response to Industrial Customer Group Information Request on the Consultants Survey Report
A2-7	Letter dated July 12, 2012 - Commission Staff Filing Response to BCOAPO Information Request to Consultants Report
A2-8	Letter dated July 12, 2012 - Commission Staff Filing Response to CEC Information Request to Consultants Report
A2-9	Letter dated July 13, 2012 – Commission Staff Filing BCUC Request for Proposal for a Survey of Canadian Cost of Capital Practice Report
A2-10	Letter dated August 31 2012 – Commission Staff Filing Behavior of the Firm under Regulatory Constraint by Harvey Averch and Leland L. Johnson
A2-11	Letter dated August 31 2012 – Commission Staff Filing Extract from Terasen 2005 and 209 ROE CAP Applications
A2-12	Letter dated August 31 2012 – Commission Staff Filing Extract from FEU 2012-13 Revenue Requirements Decision
A2-13	Letter dated August 31 2012 – Commission Staff Filing Extract from Bloomberg News (Report dated August 6, 2012)

Exhibit No.	Description
A2-14	Letter dated August 31 2012 – Commission Staff Filing Capital Structure - A Comparison
A2-15	Letter dated August 31 2012 – Commission Staff Filing Summaries of Reports and Notes from Recent Credit Rating Agencies and Investment Banks on FEI's Risk and Credit Metrics
A2-16	Letter dated August 31 2012 – Commission Staff Filing Extract from Washington Utilities and Transportation Commission Order 08 Decision
A2-17	Letter dated August 31 2012 – Commission Staff Filing Fitch Affirms National Fuel Gas' IDR at 'A'
A2-18	Letter dated August 31 2012 – Commission Staff Filing The City of Vancouver - District Energy Connectivity Standards Information for Developers
A2-19	Letter dated August 31 2012 – Commission Staff Filing City of Surrey – District Energy System By-law, 2012, No. 17667
A2-20	Letter dated August 31 2012 – Commission Staff Filing Extract from BCUC Information Request No. 2 to River District Energy Limited Partnership
A2-21	Letter dated August 31 2012 – Commission Staff Ontario Energy Board Report of the Board on the Cost of Capital for Ontario's Regulated Utilities December 11, 2009
A2-22	Letter dated August 31 2012 – Commission Staff Filing Ontario Energy Board Cost of Capital Parameter Updates for 2012 Cost of Service Applications for Rates Effective January 1, 2012
A2-23	Letter dated August 31 2012 – Commission Staff Filing Summary of Reports from Recent Credit Rating Agencies and Investment Banks on PNG's Risks and Credit Metrics
A2-24	Letter dated October 9, 2012 – Commission Staff Filing Bradshaw et al. - Playing Favorites
A2-25	Letter dated October 9, 2012 – Commission Staff Filing CTA-Risk-Free Rate Determination
A2-26	Letter dated October 9, 2012 – Commission Staff Filing Exhibit A2-26 OEB Cost of Capital Parameter, May 1 2012

Exhibit No.	Description
A2-27	Letter dated November 16, 2012 - Commission Staff Filing Cost of Capital by Sector_NYU_Value Line Database
A2-28	Letter dated November 16, 2012 - Commission Staff Filing Gau, Thompson 2012 Capitalization Rate Study
A2-29	Letter dated November 16, 2012 - Commission Staff Filing Schaeffler and Weber-The Cost of Equity of Network Operators
A2-30	Letter dated November 16, 2012 - Commission Staff Filing TD-Long-Term Returns October 2012
A2-31	Letter dated November 16, 2012 - Commission Staff Filing Ashton et al- Analysts' Optimism in Earnings Forecasts
A2-32	Letter dated November 16, 2012 - Commission Staff Filing Understanding Corporate Bond Spreads Using Credit Default Swaps
A2-33	Submitted at Oral Hearing December 12, 2012 – Commission Staff Filing FEU 2012-2013 Revenue Requirements G-44-12 Compliance Filing
A2-33-1	Submitted at Oral Hearing December 13, 2012 – Commission Staff Filing page 1 of letter dated may 1, 2012 to BCUC from FortisBC, with two pages attached
A2-34	Submitted at Oral Hearing December 13, 2012 – Commission Staff Filing Vancouver Sun Article Natural gas seen as green fuel
A2-35	Submitted at Oral Hearing December 13, 2012 – Commission Staff Filing Staff Witness Aid
A2-36	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing pages 7 to 10 from Standard & Poors Report
A2-37	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing Long-Term Economic Forecast, TD Economics, September 18, 2012
A2-38	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing Attachment 8.2(A), page 17 of 18, Results of Differences in Systematic Risk
A2-39	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing Extract from Order No. 09-176 from Public Utility Commission of Oregon

Exhibit No.	Description
A2-40	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing Rating Report, February 29, 2012 from DBRS
A2-41	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing Document Headed Moody's Investors Service, Credit Opinion: FortisBC Energy Inc.
A2-42	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing Five-Page Document, First Page Headed Returns on Average Common Stock Equity for Sample of U.S. Utilities
A2-43	Submitted at Oral Hearing December 17, 2012 – Commission Staff Filing Approaches to Estimating the Deemed Interest Rate for Long Term Debt
A2-44	Submitted at Oral Hearing December 17, 2012 – Commission Staff Filing Excerpt of FEI Kelowna DES CPCN Application
A2-45	Submitted at Oral Hearing December 17, 2012 – Document Headed Credit Rating and Equity Risk Premium
A2-46	Submitted at Oral Hearing December 18, 2012 – Commission Staff Filing Document Headed Weathering the Headwinds to Canada's Economic Growth 21 November 2012
A2-47	Submitted at Oral Hearing December 18, 2012 – Commission Staff Filing Document Headed Puget Sound Energy Inc.
A2-48	Submitted at Oral Hearing December 18, 2012 – Commission Staff Filing Document Headed Power & Utilities Research, the One-Two Punch: Growth Combined with Attractive Yield
A2-48-1	Submitted at Oral Hearing December 18, 2012 – Commission Staff Filing Extract from BMO Capital Markets, page 11, Headed Power & Utilities
A2-49	Submitted at Oral Hearing December 19, 2012 – Commission Staff Filing Extract from Ontario Energy Board, Report of Board, December 20, 2006
A2-50	Submitted at Oral Hearing December 19, 2012 – Commission Staff Filing Extract from Renewing Ontario's Electricity Distribution Sector: Putting the Consumer First
A2-51	Submitted at Oral Hearing December 19, 2012 – Commission Staff Filing Witness Aid Prepared by Commission Staff Entitled Informed Expert Judgment

Exhibit No.	**Description**
AFFECTED UTILITIES DOCUMENTS	
B1-1	**BC UTILITIES OF FORTIS INC. COMPRISED OF FORTISBC ENERGY INC., FORTISBC ENERGY VANCOUVER ISLAND INC., FORTISBC ENERGY WHISTLER INC. AND FORTISBC INC. (FBCU)** Letter Dated March 15, 2012 – Notice of Registration
B1-2	Letter Dated March 21, 2012 – FBCU Submission on the Preliminary Scoping Document
B1-3	Letter Dated May 3, 2012 – FBCU Submission on Minimum Filing Requirements
B1-4	Letter Dated May 9, 2012 – FBCU Submission regarding Order G-50-12 Appendix A
B1-5	Letter Dated June 5, 2012 – FBCU Submitting Request for Variance of Preliminary Regulatory Timetable
B1-6	Letter Dated June 5, 2012 – FBCU Reply Submissions regarding Request for Variance of Preliminary Regulatory Timetable
B1-7	Letter Dated June 22, 2012 – FBCU Submitting Information Request regarding the Commission Consultant Survey Report
B1-8	Letter Dated August 2, 2012 – FBCU Submitting comments regarding the addition of a panel member
B1-9	Letter Dated August 3, 2012 – FBCU Submitting Evidence
B1-9-1	Letter Dated August 3, 2012 – FBCU Submitting Evidence Appendix A – Sections 1 to 2
B1-9-2	Letter Dated August 3, 2012 – FBCU Submitting Evidence Appendix A – Section 3A – Debt Investment Analyst Reports for FEI
B1-9-3	Letter Dated August 3, 2012 – FBCU Submitting Evidence Appendix A – Section 3B – Equity Analyst Reports Beacon to Credit Suisse
B1-9-4	Letter Dated August 3, 2012 – FBCU Submitting Evidence Appendix A – Section 3B – Equity Analyst Reports Macquarie to UBS

Exhibit No.	Description
B1-9-5	Letter Dated August 3, 2012 – FBCU Submitting Evidence Appendix A – Sections 4 to 11
B1-9-6	Letter Dated August 3, 2012 – FBCU Submitting Evidence Appendices B to J
B1-9-7	**CONFIDENTIAL** Letter Dated August 3, 2012 – FBCU Submitting Evidence CONFIDENTIAL Appendices
B1-10	Letter Dated September 24, 2012 – FBCU Submitting Response to BCPSO IR No. 1
B1-11	Letter Dated September 24, 2012 – FBCU Response to BC Utility Customers IR1 – FBCU
B1-12	Letter Dated September 24, 2012 – FBCU Response to BC Utility Customers IR1 – A. Engen
B1-13	Letter Dated September 24, 2012 – FBCU Response to BC Utility Customers IR1 – Concentric
B1-14	Letter Dated September 24, 2012 – FBCU Response to BC Utility Customers IR1 – Dr. Vander Weide
B1-15	Letter Dated September 24, 2012 – FBCU Response to BC Utility Customers IR1 – K. McShane
B1-16	Letter Dated September 24, 2012 – FBCU Response to ICG IR No.1 – A. Engen
B1-17	Letter Dated September 24, 2012 – FBCU Response to ICG IR No.1 - Concentric
B1-18	Letter Dated September 24, 2012 – FBCU Response to ICG IR No.1 - Dr. Vander Weide
B1-19	Letter Dated September 24, 2012 – FBCU Response to ICG IR No.1 – K. McShane
B1-20	Letter Dated September 24, 2012 – FBCU Response to BCUC IR No.1
B1-20-1	**CONFIDENTIAL** Letter Dated September 24, 2012 – FBCU Confidential Response to BCUC IR No.1
B1-21	**CONFIDENTIAL** Letter Dated September 24, 2012 – FBCU Response to Confidential BCUC IR No.1

Exhibit No.	Description
B1-22	Submitted at Procedural Conference Letter Dated October 3, 2012 – FBCU Counsel's Oral Submissions
B1-23	Letter dated October 26, 2012 – FBCU Response to Confidentiality Request
B1-24	Letter dated October 29, 2012 – FBCU Response to BCUC IR No. 2
B1-25	CONFIDENTIAL Letter dated October 29, 2012 – FBCU Response to BCUC Confidential IR No. 2
B1-26	Letter dated October 29, 2012 – FBCU Response to BCPSO IR No. 2
B1-27	Letter dated November 2, 2012 – FBCU Comments regarding Confidential Material Access
B1-28	Letter dated November 16, 2012 – FBCU Submitting IR No. 1 to AMPC/BC Utility Customers on the Evidence of Dr. Booth
B1-29	Letter dated November 16, 2012 – FBCU Submitting IR No. 1 to ICG on the Evidence of Dr. Safir
B1-30	Letter Dated November 23, 2012 – FBCU Submission on Interim Rates Jan 1, 2013
B1-31	Letter Dated November 30, 2012 – FBCU Submitting Witness Panels and Direct Testimony
B1-32	Letter dated December 6, 2012 – FBCU Submitting Rebuttal Evidence
B1-33	Letter dated December 10, 2012 – FBCU Submitting Opening Statement
B1-34	Submitted at Oral Hearing December 12, 2012 – FBCU Written Opening Statement of Counsel
B1-35	Submitted at Oral Hearing December 12, 2012 – FBCU Revised: Exhibit B1-9-6, Appendix H, page 51, Figure 34
B1-36	Submitted at Oral Hearing December 12, 2012 – FBCU Undertaking No. 1
B1-37	Submitted at Oral Hearing December 12, 2012 – FBCU Undertaking No. 2
B1-38	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 3

Exhibit No.	Description
B1-39	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 4
B1-40	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 5
B1-41	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 6
B1-42	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 7
B1-43	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 8
B1-44	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 9
B1-45	Submitted at Oral Hearing December 14, 2012 – FBCU Undertaking No. 10
B1-46	Submitted at Oral Hearing December 14, 2012 – FBCU Undertaking No. 11
B1-47	Submitted at Oral Hearing December 14, 2012 – FBCU Filing Testimony of Kathleen C. McShane Tab 2
B1-48	Submitted at Oral Hearing December 17, 2012 – FBCU Undertaking No. 12
B1-49	Submitted at Oral Hearing December 18, 2012 – FBCU Filing Testimony Figures Update
B1-49-1	Letter received January 3, 2013 – FBCU Filing Remaining Chart Updates
B1-50	Submitted at Oral Hearing December 19, 2012 – FBCU Filing 104 page Collection of Documents Used in Cross Examination of Dr. Booth
B1-51	Submitted at Oral Hearing December 21, 2012 – FBCU Filing Compendium of Extracts, First Page Entitled Fair Return for Terasen Gas Inc. (TGI) August 2009
B1-52	Letter received January 3, 2013 – FBCU Undertaking No. 13
B1-53	Letter received January 3, 2013 – FBCU Undertaking No. 14
B1-54	Letter received January 3, 2013 – FBCU Undertaking No. 15
B1-55	Letter received January 3, 2013 – FBCU Undertaking No. 16
B1-56	Letter received January 3, 2013 – FBCU Undertaking No. 17
B1-57	Letter received January 3, 2013 – FBCU Undertaking No. 18

Exhibit No.	Description
B1-58	Letter received January 3, 2013 – FBCU Undertaking No. 19
B1-59	Letter received January 3, 2013 – FBCU Undertaking No. 20
B1-60	Letter received January 29, 2013 – FBCU Undertaking No. 21
B1-61	Letter received January 29, 2013 – FBCU Undertaking No. 22
B1-62	Letter received January 29, 2013 – FBCU Undertaking No. 23
B1-63	Letter received January 29, 2013 – FBCU Undertaking No. 24
B1-64	Letter received January 29, 2013 – FBCU Undertaking No. 25
B1-65	Letter received January 29, 2013 – FBCU Undertaking No. 26
B1-66	Letter received January 29, 2013 – FBCU Undertaking No. 27
B1-67	Letter received January 29, 2013 – FBCU Undertaking No. 28
B1-68	Letter received January 29, 2013 – FBCU Undertaking No. 29
B2-1	**CORIX MULTI-UTILITY SERVICES INC. (CORIX)** Letter Dated March 14, 2012 – Notice of Registration
B2-2	Letter Dated March 21, 2012 – Corix Submission on the Preliminary Scoping Document
B2-3	Letter Dated May 3, 2012 – Corix Submission on Minimum Filing Requirements
B2-4	Letter Dated May 9, 2012 – Corix Submission regarding Order G-50-12 Appendix A
B2-5	Letter Dated June 8, 2012 – Corix Submission on FBCU Request for Variance
B2-6	Letter Dated August 3, 2012 – Corix Submitting Comments Regarding the Addition of a Panel Member
B2-7	Letter Dated August 3, 2012 – Corix Submitting Evidence
B2-8	Letter Dated September 24, 2012 – Corix Submitting Response to BCPSO IR No. 1
B2-9	Letter Dated September 24, 2012 – Corix Submitting Response to BCUC IR No. 1

Exhibit No.	Description
B2-10	Letter Dated October 18, 2012 – Corix Submitting Response to BCUC IR No. 2
B2-11	Letter Dated November 23, 2012 – Corix Submission regarding A-27
B2-12	Submitted at Oral Hearing December 18, 2012 – Corix Filing Opening Remarks of Counsel for Corix Multi-Utility Services Inc., December 12, 2012
B2-13	Submitted December 24, 2012 – Corix Filing Undertaking Document Titled Before the Florida Public Service Commission
B2-14	Submitted December 24, 2012 – Corix Filing Undertaking Document titled Comparison of Business Risk Adjustments in Cost of Capital Testimony Filed by Ms. Pauline M. Ahern
B2-15	Letter received January 3, 2013 - Corix Filing Response to Undertaking
B3-1	**PACIFIC NORTHERN GAS LTD. AND PACIFIC NORTHERN GAS N.E. LTD. (PNG)** Online Registration Dated March 16, 2012 – Notice of Registration
B3-2	Letter Dated March 21, 2012 – PNG Submission on the Preliminary Scoping Document
B3-3	Letter Dated May 3, 2012 – PNG Submission on Minimum Filing Requirements
B3-4	Letter Dated May 9, 2012 – PNG Submission Regarding Order G-50-12 Appendix A
B3-5	Letter Dated June 8, 2012 – PNG Submission Regarding Variance of the Regulatory Timetable
B3-6	Letter Dated August 3, 2012 – PNG Submitting Comments Regarding the Addition of a Panel Member
B3-7	Letter Dated August 3, 2012 – PNG Submitting Evidence
B3-8	Letter Dated September 24, 2012 – PNG Submitting Response to BCUC IR No. 1
B3-9	Letter Dated September 24, 2012 – PNG Submitting Response to BCPSO
B3-10	Letter Dated September 24, 2012 – PNG Submitting Response to AMPC, BCPSO and CEC
B3-11	Letter Dated November 23, 2012 – PNG Submission Regarding A-27

Exhibit No.	Description
B3-12	Letter Dated November 30, 2012 – PNG Submitting Comments regarding Witness Panels

OTHER UTILITIES DOCUMENTS

B4-1	**BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BCH)** Letter Dated March 12, 2012 – Notice of Registration
B4-2	Letter Dated March 21, 2012 – BCH Submission on the Preliminary Scoping Document
B4-3	Letter Dated May 3, 2012 – BCH Submission on Minimum Filing Requirements
B4-4	Letter Dated May 9, 2012 – BCH Submission Regarding Order G-50-12 Appendix A
B4-5	Letter Dated June 8, 2012 – BCH Submission Regarding variance of the Regulatory Timetable
B4-6	Letter Dated August 3, 2012 – BCH Submitting Comments Regarding the Addition of a Panel Member
B4-7	Letter Dated November 23, 2012 - BCH Submission Regarding A-27
B4-8	Letter Dated November 30, 2012 – BCH Submitting Comments Regarding Witness Panels
B5-1	**RIVER DISTRICT ENERGY (RDE)** Letter Dated March 12, 2012 – Notice of Registration

INTERVENER DOCUMENTS

C1-1	**UNION GAS LIMITED (UG)** Letter dated March 5, 2012 – Request for Intervener Status by Patrick McMahon
C2-1	**CANADIAN OFFICE AND PROFESSIONAL EMPLOYEES' UNION, LOCAL 378 (COPE 378)** Letter dated March 15, 2012 – Request for Intervener Status by James Quail
C2-1-1	Letter dated March 20, 2012 – COPE 378 Submitting Intervention Supplementary Comments
C2-2	Letter dated April 19, 2012 - COPE 378 Submitting Updating Consultant details
C2-3	Letter dated June 26, 2012 - COPE 378 Submitting Updating Consultant Information

Exhibit No.	Description
C3-1	**SENTINEL ENERGY MANAGEMENT (SEM)** Online Registration dated March 20, 2012 – Request for Intervener Status by Jim Langley
C4-1	**INDUSTRIAL CUSTOMERS GROUP (ICG)** Letter dated March 20, 2012 Via Email – Request for Intervener Status by Robert Hobbs and Brian Merwin
C4-2	Letter Dated March 21, 2012 – ICG Submission on the Preliminary Scoping Document
C4-3	Letter Dated May 3, 2012 – ICG Submission regarding the Preliminary Minimum Filing Requirements for Affected Utilities
C4-4	Letter Dated May 9, 2012 – ICG Submission Regarding Order G-50-12 Appendix A
C4-5	Letter Dated June 8, 2012 – ICG Submission regarding Variance of the Regulatory Timetable
C4-6	Letter Dated June 21, 2012 – ICG Submitting Information Request Regarding the Commission Consultant Survey Report
C4-7	Letter Dated August 31, 2012 – ICG Submitting Information Request No. 1
C4-8	Letter Dated October 24, 2012 - ICG Submitting Comments regarding Request for Confidential Information
C4-9	Letter dated November 5, 2012 – ICG Submitting Evidence
C4-10	Letter dated November 6, 2012 – ICG Submitting Confidential Undertakings
C4-11	Letter dated November 30, 2012 – ICG Submitting Responses to Information Request No. 1
C4-12	Letter dated November 30, 2012 – ICG Submission Regarding Exhibit A-27
C4-13	Submitted at Oral Hearing December 12, 2012 – ICG Opening Comments
C4-14	Submitted at Oral Hearing December 14, 2012 – ICG Filing Tab 2 Testimony of Kathleen C. McShane
C4-15	Submitted at Oral Hearing December 17, 2012 – ICG Filing Opening Statement of Dr. Andrew Safir

Exhibit No.	Description
C4-16	Letter dated January 14, 2013 – ICG Submitting Undertakings
C4-17	Letter dated January 25, 2013 – ICG Submitting Dr. Lawrence Booth Undertaking No. 2
C5-1	**BRITISH COLUMBIA PENSIONERS' AND SENIORS' ORGANIZATION (BCPSO ET AL)** (previously BC Old Age Pensioner' Organization *et. al*.) **VIA EMAIL -** Letter Dated March 20, 2012 – Request for Intervener Status by Leigha Worth, Tannis Braithwaite and Bill Harper
C5-2	Letter Dated March 21, 2012 – BCOAPO Submission on the Preliminary Scoping Document
C5-3	Letter Dated May 3, 2012 – BCOAPO Submission on Minimum Filing Requirements
C5-4	Letter Dated May 9, 2012 – BCOAPO Submission Regarding Order G-50-12 Appendix A
C5-5	Letter Dated June 8, 2012 – BCOAPO Submission Regarding Variance of the Regulatory Timetable
C5-6	Letter Dated June 22, 2012 – BCOAPO Submitting Information Request Regarding the Commission Consultant Survey Report
C5-7	Letter dated July 23, 2012 – BCOAPO Submitting Notice of Name Change to British Columbia Pensioners' and Seniors' Organization (BCPSO)
C5-8	Letter Dated August 3, 2012 – BCPSO Submitting Comments Regarding the Addition of a Panel Member
C5-9	Letter Dated August 31, 2012 – BCPSO Submitting Information Request No. 1 to Corix
C5-10	Letter Dated August 31, 2012 – BCPSO Submitting Information Request No. 1 to FBCU
C5-11	Letter Dated August 31, 2012 – BCPSO Submitting Information Request No. 1 to PNG
C5-12	Letter Dated October 9, 2012 - BCPSO Submitting Information Request No. 2 to FBCU

Exhibit No.	Description
C5-13	Letter Dated October 9, 2012 - BCPSO Submitting Contact Update
C5-14	Letter Dated November 30, 2012 - BCPSO Submission Regarding Exhibit A-27
C5-15	Submitted at Oral Hearing December 17, 2012 – BCPSO Filing Business Spectator Document
C6-1	**ASSOCIATION OF MAJOR POWER CUSTOMERS OF BC (AMPC)** Letter Dated March 20, 2012 – Request for Intervener Status by Richard Stout and Lloyd Guenther
C6-2	Letter Dated May 2, 2012 – AMPC Submitting Contact Update
C6-3	Letter Dated May 3, 2012 – AMPC Submission on Minimum Filing Requirements
C6-4	Letter Dated May 9, 2012 – AMPC Submission Regarding Order G-50-12 Appendix A
C6-5	Letter Dated June 8, 2012 – AMPC Submission Regarding Variance of the Regulatory Timetable
C6-6	Letter Dated June 22, 2012 – AMPC Submitting Information Request Regarding the Commission Consultant Survey Report
C6-7	Letter Dated August 3, 2012 – AMPC Submitting Comments Regarding the Addition of a Panel Member
C6-8	Letter Dated August 31, 2012 – Filing on behalf of BCUC Utility Customers AMPC/BCPSO/CEC Information Request No. 1 to FBCU
C6-9	Letter Dated August 31, 2012 – Filing on behalf of BCUC Utility Customers AMPC/BCPSO/CEC Information Request No. 1 to FBCU on Mr. Engen's Evidence
C6-9-1	Letter Dated September 23, 2012 – Filing on behalf of BCUC Utility Customers AMPC/BCPSO/CEC Corrected Information Request No. 1 to FBCU on Mr. Engen's Evidence
C6-10	Letter Dated October 22, 2012 - AMPC Filing a Request for Confidential Information
C6-11	Letter Dated October 31, 2012 - AMPC Submitting Comments regarding Access to Confidential Information
C6-12	Letter dated November 5, 2012 – AMPC Submitting Evidence

Exhibit No.	Description
C6-13	Letter dated November 5, 2012 – AMPC Submitting Confidential Undertakings
C6-14	Letter dated November 30, 2012 – AMPC Submission regarding Exhibit A-27
C6-15	Letter dated November 30, 2012 – AMPC Submitting Responses to Information Request No. 1 to BCUC
C6-16	Letter dated November 30, 2012 – AMPC Submitting Responses to Information Request No. 1 to FBCU
C6-17	Submitted at Oral Hearing December 12, 2012 – AMPC Filing BC Natural Gas Strategy Fueling BC's Economy for the Next Decade and Beyond
C6-18	Submitted at Oral Hearing December 14, 2012 – AMPC filing AUC 2011 GCOC IR Responses CAPP McShane ROE Attach 17d
C6-19	Submitted at Oral Hearing December 14, 2012 – AMPC filing AUC 2011 GCOC IR Responses CAPP McShane ROE Attach 21 i
C6-20	Submitted at Oral Hearing December 17, 2012 – AMPC filing Alberta Utilities Commission 2009 Generic Cost of Capital Proceeding Direct Testimony of James M. Coyne
C6-21	Submitted at Oral Hearing December 18, 2012 – AMPC Filing Witness Aid Prepared by BC Utilities Customers
C6-22	Submitted at Oral Hearing December 19, 2012 – AMPC filing Dr. Booth's Opening Statement
C6-23	Letter dated January 18, 2013 – AMPC Submitting Dr. Booth Undertaking No. 1
C6-24	Letter Dated February 14, 2013 – AMPC Submitting Extension Request
C7-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (CEC)** Letter Dated March 20, 2012 – Request for Intervener Status by Christopher Weafer
C7-2	Letter Dated May 9, 2012 – CEC Submission Regarding Order G-50-12 Appendix A
C7-3	Letter Dated June 8, 2012 – CEC Submission Regarding variance of the Regulatory Timetable

Exhibit No.	**Description**
C7-4	Letter dated June 25, 2012 – CEC Submitting Information Request Regarding the Commission Consultant Survey Report
C7-5	Letter Dated August 3, 2012 – CEC Submitting Comments Regarding the Addition of a Panel Member
C7-6	Letter dated November 9, 2012 – CEC Submitting Confidential Undertakings

INTERESTED PARTY DOCUMENTS

D-1	**AT BUSINESS CONSULTING (ATB)** Online Registration dated May 9, 2012 – Request for Interested Party Status by Anastasios Tsalamandris

ORDER C-1-13
ATTACHMENT B

	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
	Capital structure (debt/equity ratio)	60/40 (actual)	60/40 (actual)	60/40 (actual; proposed)		60/40 (actual)	Deemed 60/40	Deemed 60/40	Deemed 60/40
	Equity Risk Premium	N/A	0 bps (approved)	50 bps (proposed)		50 bps (approved)	50 bps (approved)	100 bps (approved)	50 bps (approved)
1	Technology risk/system performance risk associated with chosen technologies	Natural Gas: proven technology	Geo-exchange loop field system and heat recovery with high efficiency natural gas boilers equipment	Recovered waste heat from TELUS Data Centre with peaking and redundant backup heat supplied by Centre Heat Distribution Ltd.: low risk	Slightly higher for PCI / TG than FEI NG	High efficiency condensing boilers: proven technology; Ground source heat pumps; less established technology	Natural gas boilers proven technology	Biomass Gasification innovative technology; Natural Gas boilers; proven technology (while DGE not yet on biomass, the Commission approved the technology)	Natural Gas: boiler: proven technology

ORDER C-1-13
ATTACHMENT B

	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
2	Fuel Risk cost and availability	Natural gas: Low-medium	Low risk: free energy from ground and heat recovery, but cost risk for electricity used to operate heat pumps and TES equipment, and for natural gas for supplementary heat and peaking	Data Centre that supplies waste heat is assumed to be available throughout the 20 year term of the analysis: low risk Data Centre ceases operation	Lower for PCI / TG than FEI NG	Natural gas and electricity: Low-medium; Heat from ground: low (some energy cost risk in electricity costs to operate GSHPs)	Natural gas fuelled energy centre: low medium Alternative renewable energy source: not approved yet and thus not relevant	Biomass: medium-high; natural gas; low-medium	Natural gas fuelled energy centre: low medium Alternative renewable energy source: not approved yet and thus not relevant
3	Customer Base (e.g., diversity, certainty, growing, declining)	Established and diverse customer base but very slow growth	Greenfield utility four types of customers	Not large customer base or significant diversity: low risk	Higher for PCI / TG than FEI NG (NG has much greater diversity)	Established customer: low risk	Greenfield utility: uncertainty related to timing of full build out	Greenfield utility: uncertainty related to timing of full build out	Greenfield utility: uncertainty related to timing of full build out
4	Default risk of customer	Minimal	Minimal	Minimal	Similar for PCI / TG as for FEI NG	Minimal as SD has budget constraints as well	Minimal	Minimal	Minimal

ORDER C-1-13
ATTACHMENT B

	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
5	Property development risk	Medium to high: there are competing energy options	Low risk: all customers bound by agreement	Majority of tenants committed but customers can still leave: low risk	Lower for PCI / TG than FEI NG	None, as not a new development	Low: phased approach to capital deployment	High: build first approach to capital deployment	Low: phased approach to capital deployment
6	Developer / customer connection risk	Medium to high: due to building stock changes and competitive energy sources	Low Risk: customers will connect on occupancy	Low Risk: customers will connect on occupancy	Lower for PCI / TG than FEI NG	Low, as one known customer with existing sites	Low: mandatory connection	Low: mandatory connection	Low: mandatory connection
7	Load Forecast Uncertainty	Minimal in the short term, as mature utility with deferral account; somewhat higher in the long term	Inherent uncertainty in load forecast	FAES proposes to take forecast risk on actual energy throughput versus forecast for 5 year period: Low-medium	Higher for PCI / TG than FEI NG	Low, as established energy load	Inherent uncertainty in load forecast	Inherent uncertainty in load forecast	Inherent uncertainty in load forecast

ORDER C-1-13
ATTACHMENT B

	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
8	Utility size	Large and mature utility	Project is carried out by a separate corporate entity, Small development specific utility.	Project is carried out by separate corporate entity, Small development specific utility.	Higher for PCI / TG than FEI NG	Project is carried out by separate corporate entity	Small development specific utility	Small development specific utility	Small development specific utility
9	Initial construction cost risk	Depends on the nature of the individual project	Depends on nature of the individual project	Depends on nature of the individual project	Similar for PCI / TG as for FEI NG	Depends on the nature of the individual project	Depends on the nature of the individual project	Depends on the nature of the individual project	Depends on the nature of the individual project
10	Future Construction cost risk	Depends on the nature of the individual project	Depends on nature of the individual project	Depends on nature of the individual project	Similar for PCI / TG as for FEI NG	Depends on the nature of the individual project	Depends on the nature of the individual project	Depends on the nature of the individual project	Depends on the nature of the individual project
11	Operating cost risk	Minimal as revenue requirement application to recover costs	Minimal as mechanism in place to recover costs	Low-medium risk: as deferral accounts do not cover all O&M variances between forecast and actual	Higher for TG, similar for PCI relative to FEI NG	Minimal as mechanism in place to recover costs	Minimal as a mechanism in place to recover costs	Minimal as a mechanism in place to recover costs	Minimal as a mechanism in place to recover costs

ORDER C-1-13
ATTACHMENT B

	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
12	Public Acceptance Risk	Medium as natural gas is an established and widely used technology but public perceives it as less than clean	Low as seen as green alternative	Low	Lower for PCI / TG than FEI NG	Low as seen as green alternative	Low as seen as a green alternative	Low as gasification technology part of approval process for the development and already selected at the time of the CPCN application	low as seen as a green alternative
13	Fixed/Variable rate design	15% fixed/85% variable	~~100% variable~~ Rate Design Not Approved	100% variable (volume rate)	Higher for TG, relative to FEI NG PCI Rate Design not Approved	100% variable	60% fixed/40% variable	50% fixed/50% variable	66% fixed / 34% variable

ORDER C-1-13
ATTACHMENT B

	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
14	Levelized approach to rates	No	~~Only in first three years then transition to cost of service~~ Rate Design not Approved	The rates charged for the first five years have been mutually agreed upon using a benchmark based on BC Hydro RIB Step 1 and Step 2	Slightly higher for TG, relative to FEI NG PCI Rate Design Not Approved	No, transitional market rate and deferral account	Yes	Yes	Yes
15	Financial risk	Low-medium: appropriate standalone financing structure for capital markets	Medium (similar to DSD)	Forecast risk and rates fixed for first five years (other than one-time adjustment for GCOC changes) impacts financial risk: medium risk justifies 50 bps on FEI utility benchmark	Higher for PCI / TG than FEI NG	Medium	Low-medium: subsidiary of parent utility	Low-medium: subsidiary of parent utility	Low-medium: subsidiary of parent utility

ORDER C-1-13
ATTACHMENT B

	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
16	Competitive challenges	Competitive with electricity and competition from alternative energy providers	Other TES providers and electricity	Other TES providers and electricity	Lower for PCI / TG than FEI NG	Other TES providers and electricity	Other utilities and electricity	Other utilities and electricity	Other utilities and electricity
17	Provincial climate change and energy policies	Encourage reduction of fossil fuels usage to reduce GHG emissions and lower energy use.	Favourable government policies	Favourable government policies	Lower for PCI / TG than FEI NG	Favorable govt. policies	Favourable govt. policies	Favourable govt. policies	Favourable govt. policies
18	Regulatory uncertainty	Low to medium: uncertainty exists for service offerings within the natural gas class of service.	Medium risk: New, uncertainty, scrutiny and not streamlined Rate Design Denied as Applied	Medium risk: New, uncertainty, scrutiny and not streamlined	Higher for PCI / TG than FEI NG	Medium risk: new, uncertainty, scrutiny and not streamlined	Medium risk: New, uncertainty, scrutiny, alternative energy centre not yet approved	Medium risk: New, uncertainty, scrutiny	Medium risk: New, uncertainty, scrutiny

ORDER C-1-13
ATTACHMENT B

	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
19	Business Development Risk	Minimal	Low – deferring business development costs increases risk of non-recovery. (PCI BCUC IR 1.41.1.) [Shareholder ultimately at risk for the TESDA]	FAES has agreed to purchase the TGTES from the Partnership upon commissioning for actual construction cost of $7.9 million up to a maximum of 30% above the $7.9 million estimate.	Higher for PCI / TG than FEI NG	Low: deferring business development costs increases risk of non-recovery. (PCI BCUC IR 1.41.1) (Shareholder ultimately at risk for the TESDA)	High as part of overhead cots	High as part of overhead cots	High as part of overhead cots

COST OF CAPITAL ESTIMATION MODELS AND KEY INPUTS

DISCOUNTED CASH FLOW MODELS

Analyst	Model Sub-type	Sample	Growth Estimate	ROE est. (%)	References
McShane	Constant Growth	12 US utilities	4.9% - Average of consensus earnings forecasts from Bloomberg, Reuters, ValueLIne and Zacks.	9.3	McShane Evid, Table 30, p. 113; App. C, and Schedule 19
	Constant Growth	5 Can utilities (incl. Fortis Inc.)	7.5% - Reuters L-T EPS forecasts	11.0	McShane Evid, Table 30, p. 113 and Schedule 22
	Sustainable Growth	12 US Utilities	4.4% - Avg of sustainable growth rates for US utilities derived from Value Line forecasts of ROEs, earnings retention rates and earnings growth from external financing.	8.7	McShane Evid, Table 30, p. 113 and Schedule 20
	Three Stage Model	5 Can utilities (incl. Fortis Inc.)	Stage 1 (yrs 1-5) - Reuters L-T EPS forecasts: 7.5% Stage 2 (yrs 6-10)- Avg of stages 1 and 3: 5.9% Stage 3 (yrs 11+)-GDP growth: 4.3%	8.6	McShane Evid, Table 30, p. 113 App. C and Schedule 23
	Three Stage Model	12 US utilities	Stage 1 (yrs 1-5) - Avg of all EPS forecasts: 4.9% Stage 2 (yrs 6-10) - Avg of stages 1 and 3: 4.9% Stage 3 (yrs 11+) - GDP growth: 4.9%	9.2	McShane Evid, Table 30, p. 113 and Schedule 21
	Mid-point of range	Canadian sample		9.8	McShane Evid. p. 113
	Mid-point of range	Both samples		9.4	McShane Evid. p. 113
			Bare bones Cost of Equity estimated at 9.4% and add Financing Flexibility Adjustment of 0.5%	9.9	

...DCF MODELS

Analyst	Model Sub-type	Sample	Growth Estimate	ROE est. (%)	References
Vander Weide	Quarterly DCF model	Comprehensive group of 32 US utilities	Range: 3.15% to 9.75% I/B/E/S Thomson Reuters mean growth forecasts	Range: 7.4-14.6 Avg: 9.8	VdW Evid, p. 28 – 30 and Exhibit 6
		Small group of 19 US utilities (subset of large group)	Range: 3.15% to 9.75% I/B/E/S Thomson Reuters mean growth forecasts	Range: 7.4-14.6 Avg: 9.5	VdW Evid, p. 28 – 30 and Exhibit 7
			Bare-bones cost of equity for the Comprehensive Model 9.8% plus Financing Flexibility	10.3	
			Bare-bones cost of equity for the Small Utilities Model 9.5% plus Financing Flexibility	10.0	
			Summary of results from DCF	10.15	
Booth		All of Canadian market	Growth rate range 4.7% - 6.1% based on multiplying corporate Canada ROEs since 1987 times retention rates.	9.3	Booth Evid., p. 94 & App D, p. 9-10
		US market – S&P 500	Growth rate range of 6.79% - 7.97% based on multiplying the average and median values respectively for S&P 500 ROEs since 1977 times the current dividend yield	Calculated range: 8.93-10.01. Adjusted range: 9.5-10.5	Booth Evid., App D, p. 10-13 (Note disc. of analyst forecasts at p. 14-17.)

...DCF MODELS

Analyst	Model Sub-type	Sample	Growth Estimate	ROE est. (%)	References
Safir	Two-stage model	Canadian Sample - 5 Can. utilities (incl. Fortis)	Stage 1 (analyst forecasts)- 7.49%; Stage 2 (GDP growth) – 4.49% Weighted average (33/67): 5.49%	8.99	Safir Evid, p. 24-26, and Schedule 3
	Two-stage model	US Sample – 18 US utilities	Stage 1 (analyst forecasts) - 5.50%; Stage 2 (GDP growth) – 4.57% Weighted average (33/67): 4.88%	8.86	Safir Evid,p. 24-26, and Schedule 4
			ROE Adjusted by Flotation Costs at 5% for Canadian sample	9.46	Safir Evid. p. 26
			ROE Adjusted by Flotation Costs at 5% for US sample	9.33	Safir Evid. p. 26

CAPITAL ASSET PRICING MODELS

Analyst	Model Sub-type	Risk Free Rate	Market Risk Premium	Beta Estimate	ROE est. (%)	References
McShane	See her Risk-Adjusted Equity Risk Premium Model					

Vander Weide	N/A – Vander Weide recommends placing no weight on CAPM results	2.95% forecast yield to maturity on L-C bonds	6.6% - Ibbotson SBBI estimate of risk premium on market portfolio – diff. between arithmetic mean return on S&P 500 vs. income return on 20-year Treasury bonds. (1937-2012)	0.73 – Average Value Line beta for his large proxy US utility group.	8.27 (including financial flexibility)	Vander Weide Evid, pp. 38-44; Exhibits 12 to 15
				0.92 – historical ratio of the average utility risk premium to the S&P risk premium	9.52 (including financial flexibility)	

Booth	Simple CAPM estimate	3.00% (Base adjusted LTC forecast)	Range: 5.0 – 6.0%	Range: 0.45-0.55	Range: 5.75-6.80, including 0.50 flotation cost allowance	Booth Evid, p. 74 & 75; App. B (MRP), p. 16, App. C (beta est), pp. 10-14
	Adjusted CAPM (Simple CAPM plus 0.40 for credit spread and 0.80 for Operation Twist.	3.80% (Base adjusted LTC forecast)	Same as above	Same as above	Range: 6.95 to 8.00 (2013) 7.00 -8.00 Including flotation cost allowance	Booth Evid, p. 85, 93-94 (adjustments); other values same as above.
				Point estimate for CAPM	7.5	Booth Evid. p. 95

...CAPITAL ASSET PRICING MODELS

Analyst	Model Sub-type	Risk Free Rate	Market Risk Premium	Beta Estimate	ROE est. (%)	References
Safir	Canadian CAPM	4.00%	5.96% (Total mkt. return minus the est annual long bond income return (both 1924-2010)	Adjusted beta: 0.36 (weighted 0.67 raw + 0.33 mkt tendency) Calculated raw beta (Sched 1): 0.25 Long-run mkt tendency beta (Schaeffler & Weber survey): 0.58	6.15	Safir Evid. p. 12-15 and Schedule 1
	US CAPM	4.50%	6.62% (Total mkt. return minus the est annual long bond income return (both 1926-2011)	Adjusted beta: 0.48 (weighted 0.67 raw + 0.33 market tendency) Calculated raw beta (Schedule 2): 0.43 Long-run market tendency beta (Schaeffler & Weber survey): 0.58	7.68	Safir Evid. p. 18 and Schedule 2
				Adjusted by flotation cost allowance of 0.32% for the Canadian ROE estimate	6.47	Safir Evid. p. 12
				Adjusted by flotation cost allowance of 0.40% for the US ROE estimate	8.08	Safir Evid. p. 18

EQUITY RISK PREMIUM MODELS

Analyst	Model Sub-type	Risk Free Rate	Market Risk Premium	Beta Estimate	ROE est. (%)	References
McShane	Risk-adjusted ERP (variant of CAPM)	4.0% (forecast 30 yr Long-Can bond yield)	7.25-7.5% (based on bond income returns < 8.0%; table 12, pp. 82, 98 of her evid)	0.65-0.70 adjusted (0.65 based on Bloomberg adjusted betas for 5 Can utilities or raw beta for TSX utilities index adjusted per Bloomberg (.67 raw+0.33; see McShane evid. p. 97. For upper end of range see table 21, p. 98)	Range: 8.9-9.1% Est. 9.0%	McShane Evidence, p. 98
	DCF Based ERP Models: 1998-2012 Q1 US Sample					
	Constant Growth – Single variable (L-C bond rate)	4.0% (forecast 30 yr L-C yield)	5.7% at 4.0% risk free rate (see table 22, p. 100)	N/A	9.7%	McShane evid. p. 99-101
	3-stage growth - single variable	4.0%	5.7 or 5.8% at 4.0 risk free rate (apparent inconsistency between tables 24 and 25)	N/A	9.7	McShane evid p. 99-105
	Constant Growth – two variable (L-C bonds and 30 year A-rated utility yield spreads)	4.0%	5.5%	N/A	9.5	McShane evid at pp. 102-105, esp. table 25.
(cont….)	3-stage growth – two variable	4.0%	5.6%	N/A	9.6	McShane evid at pp. 102-105, esp. table 25.

…EQUITY RISK PREMIUM MODELS

Analyst	Model Sub-type	Risk Free Rate	Market Risk Premium	Beta Estimate	ROE est. (%)	References
McShane (cont. from previous page)	*DCF Based ERP Models*: 1998-2012Q1 US Sample (continued from previous page)					
	Quarterly US utility ROE's as proxy for utility cost of equity – single variable	4.0%	6.2%		10.2 (McShane gives no weight)	McShane evid at pp. 102-105, esp. table 25
	Quarterly US utility ROE's– two variable	4.0%	6.1%		10.1 (no weight)	McShane evid at pp. 102-105, esp. table 25
	Constant Growth over A-rated bond	5.35% (4.0% L-C bond yield + 135 bp)	4.0		9.4	McShane evid at p. 105, table 26
	3-stage growth over A-rated bond	5.35% (as above)	4.2		9.6	McShane evid at p. 105, table 26
	Allowed ROEs over A-rated bond	5.35% (as above)	4.8		10.2 (no weight)	McShane evid at p. 105, table 26
	Summary of results DCF based results	4.0%% (f'cast L-C bond yields) or 5.35% (A-rated utility bond yields	Range of regression results		9.4 – 9.7	McShane Evid. p. 106
(cont…)			Bare bones Cost of Equity (mid-point)		9.6	

…EQUITY RISK PREMIUM MODELS

Analyst	Model Sub-type	Risk Free Rate	Equity Returns	Bond Inc. Returns	Utility Risk Premium	Change in Bond Yield/Ret	Change in Util Risk Pr.	Utility Equity Risk	ROE est. (%)	References
McShane (cont. from previous page)	Historic Utility ERP- Can utilities (1956-2011)	4.0%	12.1%	7.3%	4.8%	-3.3%	+1.6%	6.4%	10.5 (based on all 3 Historic Utility ERP tests)	McShane Evid. pp. 106-108
	Historic Utility ERP- US Gas Utilities (1947-2011)	4.0%	11.9%	5.9%	6.0%	-1.9%	+1.0%	7.0%		McShane Evid. pp. 106-108
	Historic Utility ERP- US Elec Utilities (1947-2011)	4.0%	11.0%	5.9%	5.1%	-1.9%	+1.0%	6.2%		McShane Evid. pp. 106-108
	Summary of All Risk Premium Tests	Risk-Adjusted Equity Market							9.0	McShane Evid p. 109, table 29
		DCF-based							9.6	
		Historic Utility							10.5	

Analyst			Stock Returns	Avg Bond Yields	Risk Premium	Expected bond yield		
Vander Weide (cont…)	Ex-Post Risk Premium	S&P/TSX Utilities: 1956-2011	11.99%	7.33%	4.7%	N/A	N/A	Vander Weide Evid, pp. 32-35, 44; and Exhiibits 8 & 9
		BMO Utilities: 1983-2011	16.01	7.24	8.8%	N/A	N/A	
		Average risk premium of the two samples			6.7%	2.95%	10.15 (rounded to 10.2% (incl. 0.5% flotation	

...EQUITY RISK PREMIUM MODELS

Analyst	Model sub-Type	Sample Group and Period	DCF Growth rate	Risk Prem.	Risk Free Rate	Roe est. (%)	References
Vander Weide (cont. from previous page)	Ex-Ante Risk Premium	Natural Gas group selected from S&P nat. gas companies	DCF growth rate and analysis by individual company from I/B/E/S forecast of earnings growth for each month. (Exhibits 10 & 11)	8.0%	2.95%	11.5 (incl flotation)	Vander Weide Evid. pp. 35-38 and App. 3, Exhibits 10, 11 and 24
		Moody's group of 24 Electric utilities.		7.5%	2.95%	11.0 (incl flotation)	
Booth	N/A						
Safir	N/A						

COMPARABLE EARNINGS TESTS

Analyst	Model sub-Type	Sample Group and Period	ROE est. (%)	References
McShane	Book-value based	21 Canadian unregulated companies: 2004-2011 (incl downward adjustments of 125 to 150 bps)	Range: 11.0-12.0 Est: 11.5	McShane Evid, pp. 113-117, 119 and App E.
Vander Weide	N/A		N/A	
Booth	Book-value based	Corporate Canada (Statistics Canada reported earnings): 1987-2011, and TSX composite for the same period	Market ret: 9.3	Booth Evid. p. 93 and App. E, Schedule 2
Safir	Market-value based	Canadian sample: same 21 Canadian Companies as used by McShane: 2004-2011	6.85	Safir Evid. pp. 28-35 and Schedules 5 and 6
	Market-value based	US Sample: 31 US companies in the consumer goods, industrial goods or service sectors using same selection critiera as McShane used for her Canadian sample: 2004-2011.	5.81	
	Weighted average giving Canadian results twice the weight of the US results		6.50	

SUMMARY OF ROE RECOMMENDATIONS

Analyst	Method	Model Sub-Type	'Bare-bones' Cost of Equity"	Financing Flexibility Adjustment	ROE est. (%)	References
McShane	DCF		9.4%	0.50%	9.9	McShane Evid. pp. 6 and 119
	Risk Premium	Risk-Adj Equity Mkt	9.0%	0.50%	9.5	
		DCF-based	9.6%	0.50%	10.1	
		Historic Utility	10.5%	0.50%	11.0	
	Comp. Earning		N/A	N/A	11.5	
VanderWeide	DCF		9.5%	0.5%	10.15	Vander Weide Evid. p. 44 and Exhibit 7
	CAPM	Calulates ROEs (incl. flotation allowance) of 8.27% and 9.52% but gives the CAPM results no weight			N/A	Vander Weide Evid. p. 44 and Exhibits 12 and 13
	Risk Premium	Ex-Post RP	9.65%	0.50%	10.15 (10.2)	Vander Weide Evid. pp. 35, 38 and 44, and Exhibits 8, 9, 10, 11 and 24
		Ex-Ante RP (average of Natural Gas and Elec. Samples	10.75%	0.50%	11.25	
Booth	Discounted Cash Flow	All of Canadian market	9.28% for the market as a whole		N/A	Booth Evid. p. 93-94 and App. D, pp. 9-10
		US market – S&P 500	9.5% - 10.5% for the US market		N/A	
	CAPM	Adjusted for credit spread and Operation Twist	6.95-7.50%	0.50%	7.50	Booth Evid. pp. 93-94
	Comp. Earning	Market Returns	9.3% for Corporate Canada (StatsCan)		N/A	Booth Evid, p. 93-94; App. E, pp. 2-7
Safir	DCF	Canadian Sample	8.99%	0.47%	9.46	Safir Evid, p. 26
		US Sample	8.86%	0.47%	9.33	
	CAPM	Canadian Sample	6.15%	0.32%	6.47	Safir Evid. p. 12
		US Sample	7.68%	0.40%	8.08	Safir Evid. p. 18
		Weighted average	N/A	N/A	7.01	Safir Evid, p. 19
	Comp Earning	Market value based results; wighted avg of Can and US results			6.50	Safir Evid. p. 33

LIST OF ACRONYMS

AAM	Automatic Adjustment Mechanism
AECO	Alberta's gas trading price
AES	Alternative Energy Services
AMPC	Association of Major Power Consumers
AUB	Alberta Utilities Commission
B	Beta
BA	Bankers' Acceptances
BCPSO	British Columbia Pensioners' and Seniors' Organization
BCUC	British Columbia Utilities Commission
BC Utility Customers	Collectively AMPC, BCPSO, CEC
bps	Basis points
CAPM	Capital Asset Pricing Model
CDOR	Canadian Dealer Offered Rate
CEC	Commercial Energy Consumers of B.C.
CEA	Clean Energy Act
Concentric	Concentric Economic Advisers
CPCN	Certificate of Public Convenience and Necessity
DCF	Discounted Cash Flow
ERP	Equity Risk Premium
FRS	Fair Return Standard
FBCU	FortisBC Utilities
Fl PUC	Florida Public Service Commission

LIST OF ACRONYMS

GCOC	Generic Cost of Capital
GJ	Gigajoule
ICG	Industrial Customers Group of FortisBC Inc.
LCBF	Long Canada Bond Forecast
NEB	National Energy Board
O&M	Operation and Maintenance
PBR	Performance Based Ratemaking
PNG	Pacific Northern Gas
PRMP	Price Risk Management Plan
OEB	Ontario Energy Board
ROE	Return on Equity
r_m	Expected return on the market
r_f	Risk free rate
$r_m - r_f$	Market risk premium
r_e	Opportunity cost of equity
Régie	Régie de l'Energie
TES	Thermal Energy Services
Terasen, TGI	Terasen Utilities, Terasen Gas Inc.
UCA	Utilities Commission Act
UPC	Use Per Customer