**Q. Evidence of Kathleen McShane: Please provide an update reply to CA-NP-369 from Newfoundland Power's 2010 GRA.**

A. Extracts from Board Decisions since Ms. McShane's reply to CA-NP-369 from Newfoundland Power's 2010 GRA are attached as follows:

Alberta Utilities Commission, 2009 Generic Cost of Capital, Nov 12, 2009.

Ontario Energy Board, Cost of Capital for Ontario's Regulated Utilities, Dec 11 2009.

BC Utilities Commission, Terasen Gas Decision on Return on Equity and Capital Structure, Dec 16 2009.

Newfoundland & Labrador Board of Commissioners of Public Utilities, Decision 43(2009), Dec 24 2009.

Island Regulatory and Appeals Commission, Maritime Electric Order UE10-03, Jul 12 2010.

Regie De L'Energie, Gazifere Decision 2010-147, Nov 26 2010.

New Brunswick Energy and Utilities Board, Cost of Capital for Enbridge Gas New Brunswick, Nov 30 2010.

Ontario Energy Board, Natural Resource Gas Rate Application, Dec 6 2010.

Ontario Energy Board, Ontario Power Generation Decision EB-2010-0008, Mar 10 2011.

Alberta Utilities Commission, ATCO Electric Decision 2011-134, Apr 13 2011.

Alberta Utilities Commission, 2011 Generic Cost of Capital, Dec 8 2011.

Decision 2009-216

AUC
Alberta Utilities Commission

# 2009 Generic Cost of Capital

November 12, 2009

return for Alberta utilities. As a consequence, the Commission is left with data relating to proxy groups involving smaller, mostly local, gas and electric distribution companies to consider.

#### 3.2.2.3 Differences in Regulatory Practices

160. The Commission notes the attributes of utility regulation in Canada as enumerated by Dr. Booth which serve to reduce regulatory risk for Canadian utilities:

> The history of regulation in Canada is that when risks arise to potentially cause losses to utilities they are invariably transferred to rate payers as part of the dynamics of regulation. This dynamic is illustrated through:
> - the adoption of forward test years;
> - the removal of the commodity charge through fuel pass through for LDCs;
> - the removal of the merchant function;
> - the adoption of weather related deferral accounts;
> - increasing focus on the core service where the utility has market power;
> - the reduction in regulatory lag;
> - increased fixed charge component in rates
> - the adoption of ROE formula adjustments;
> - review of depreciation studies when stranded asset risk changes;
> - flexible hearings to review unique risks.
>
> All these policies have served to reduce the risk of regulated utilities in Canada. The fact is that regulation is a flexible process that moderates or shares these risks even if they do materialize to the extent that the regulated utility is rarely hurt. A case in point is Pacific Northern Gas (PNG), which I regard as the riskiest regulated utility in Canada.[116]

161. Mr. Coyne suggested in his evidence that many of the above features of Canadian regulation can also be found in the U.S.[117] Ms. McShane had the following discussion with Commission Counsel on this topic:

> Q. But in terms of comparability, I'm trying to figure out if you're suggesting that the US has moved more to be Canadian-like or Canadians have become more American-like; if that helps?
> A. MS. McSHANE: Well, I think that American utilities have probably adopted more -- additional mechanisms since 2004 than Canadian utilities have, in the aggregate.
> Q. So how does that enhance the comparability of the two?
> A. MS. McSHANE: Because I don't think that you could say today that there is a significant difference, material difference, in the degree of protection.
> Q. So, again, it sounds like you're suggesting that the American utilities have adopted mechanisms to reduce their risk that make them more like Canadian utilities in terms of deferral accounts and protections that they have available to them; is that what you're saying?
> A. MS. McSHANE: Yes, if I looked at the trend in the US, I would say there had been a trend over the past five years to adopting revenue decoupling; more adoption of weather normalization; adoption of riders to automatically add new plant to the rate base.[118]

116 Revised Evidence of Dr. Booth, Exhibit 292.03, pages 65-66.
117 Written Evidence of Mr. Coyne, Exhibit 50.01 Section 3, starting at page 54.
118 Transcript, page 1742, line 7 to page 1743, line 2.

162. Specifically with respect to the use of deferral accounts, the Commission notes the following comment of Mr. Coyne:

> Deferral accounts arguably reduce, to some extent, the risk of utilities because the accounts are intended to allow for the recovery of certain costs over a specified period of time. The deferral account helps the utility to stabilize the volatility of its quarterly cash flows and earnings, and to improve the utility's opportunity to earn its authorized rate of return. However, deferral accounts cannot fully eliminate the utility's risk because they are subject to a prudency standard.).[119]

163. The use of deferral accounts in Alberta and the additional legislative provisions requiring a utility to proceed with direct assign electric transmission projects and the legislative protections provided with respect to direct assign projects was the subject of an exchange on risk faced by Alberta TFOs between Mr. Frehlich, Chief Operating Officer of AltaLink and Commission Counsel:

> Q. And sir, aren't some of these business and operational risks mitigated by the history of backstopping arrangements that you've had with the AESO for projects like the last 500kV, the number of deferral accounts that deal with direct-assign projects, and the provisions of the transmission regulation, in particular, Section 39, which allows a TFO to include in its tariff, preconstruction costs incurred up to the -- incurred by the TFO with direct-assign projects, up to the issuance of permit and licence, including feasibility studies, engineering, purchase of materials and rights of way?
> A. MR. FREHLICH: Mr. McNulty, in response to your question. As it relates to, I'll pick a point in time, 2004, when we were last in the generic cost of capital process, the majority of the risk mitigation methods that you describe were already in place at that time. So there is not a material change from 2004 in that domain. The TFO has always been able to recover their prudently incurred costs, preconstruction and post-instruction, into the rate base. What we're describing here is essentially, as we go through this build there will be an increase in the execution risk for us as a business. And it's essentially to provide that, directionally, business risk is increasing compared to 2004. It's in support of Mr. Vander Weide's evidence that our fair return should be set at 38 and 11.
> Q. Sir, what I'm trying to understand is where the real risk is. If you have deferral accounts to cover your direct-assign projects that cover the actual versus the forecasted costs, if you have deferral accounts that deal with the changes in the forecast versus actual debt, if you have Section 37 -- sorry, 39 of the transmission regulation that allows you to recover preconstruction costs whether the project goes ahead or not, where is your risk other than the fact that you need to be prudent in what you spend?
> A. MR. FREHLICH: We use that term in such a short sentence that it seems like it's such a simple thing to do, to effectively execute billions of dollars worth of projects prudently. The fair return for our organization should be set based on the risks our business is exposed to; deferral accounts for direct-assigns have been placed prior to 2004. So the risk as a company that we're exposed to, is exactly that, the prudency risk; and it is the ability to effectively execute all of those projects prudently, is what the risk is that we're exposed to.[120]

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[119] Written Evidence of Mr. Coyne, Exhibit 50.01, Section 3, page 56.

[120] Transcript, page 287, line 23 to page 290, line 4.

164. In response to questions from counsel for CAPP Mr. Frehlich described his understanding of the protections provided to Alberta TFOs by section 42 of the *Transmission Regulation*[121] passed pursuant to the *Electric Utilities Act*:

> Q. So in that respect, AltaLink is special, if I can put it that way, in that it's treated somewhat differently than the non-TFO utilities before this Commission?
> A. MR. FREHLICH: I'm not going to speak for other utilities in front of the Commission. Our situation is as we've provided in our evidence around our credit metrics, and so as it relates to our credit situation, yes, we would see section 42 as providing the Commission with guidance around ensuring that we as a TFO in our situation have a stable investment climate and a steady stream of capital, especially through this build. And for us a stable investment climate relates to maintaining our A rating as we go forward through this build.

165. The Commission also notes that Mr. Coyne did not undertake a specific review of Alberta legislation before preparing his evidence and making his conclusions on the comparability of risks between U.S. and Alberta utilities as reflected in the following exchange with Commission Counsel.

> Q. Sir, I'm not quite sure I got the answer to half of the question. That is, did you look at the Alberta legislation?
> A. MR. COYNE: I did not specifically examine pieces of Alberta legislation. I had considerable discussion with the ATCO utilities, their representatives.
> I have been working with the Alberta AESO for some -- over a period of time in the context of WECC [Western Electricity Coordinating Council]. So I was aware of what the electric transmission policies and procedures were within WECC and within Alberta.
> So I would say it was more of a combined collection of analysis, expertise of those in the ATCO utilities in our team that we brought to bear.[122]

166. The Commission does not consider the fact that the actions of the utility in administering a deferral account must be prudent or that it must prudently manage its project costs materially alter the protections against business risk afforded to a utility in Alberta. Although, both Mr. Coyne and Ms. McShane have suggested that many of the deferral account provisions such as purchased gas adjustments, fuel cost recovery mechanisms, purchased power contract adjustments and weather normalization provisions afforded to Alberta utilities have some degree of corresponding protections in the proxy group of U.S. utilities, a thorough comparative analysis of the various deferral accounts and legislative protections available to Alberta utilities was not undertaken in support of this position. The Commission considers that there is ample evidence to demonstrate that the support provided by the legislative and regulatory context in Alberta materially reduces regulatory and other business risks of Alberta utilities when compared to the evidence proffered on U.S. utilities in this proceeding.

167. With respect to some of the additional attributes referred to by Dr. Booth and their use or lack thereof in the United States, the Commission notes the following exchange between Mr. Marcus appearing for the UCA and Commissioner Michaud:

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121 AR 86/2007, as amended.

122 Transcript, page 1147, lines 6-17.

Q. ...As you know, we've heard there is a lot of evidence from -- a lot of expert evidence on the record regarding U.S. and Canadian risk comparisons and opinions on that as to how the U.S. and Canada are -- according to Ms. McShane, for example, there is a narrowing of the gap between U.S. utilities and Canadian utilities from a risk perspective. And looking at your evidence, obviously you were not asked to comment on that, but you mentioned that Canadian regulation generally in Alberta, regulation specifically, makes greater use of forecasts, future test years than does American regulation, and then you go on to say this aspect of Canadian regulation renders it somewhat more supportive of utilities.

That's one glimpse into your thinking on that. I'm just wondering what your opinion is, generally, on the narrowing of the gap or where we're at today with respect to that issue.

Is Canada closer in risk to risk levels to US utilities or not?

A. MR. MARCUS: I'm going to start by saying when you look at financial analysis of utilities, you have to start by saying what is a utility. I know that's an elementary question, but many of the items that are called utilities by the U.S. financial services have large amounts of deregulated generations attached to them so that you don't have -- you have a limited number of pure play wires utilities. And when you look at, for example, an analysis of discounted cash flow of US utilities, you will find that the ones that have unregulated generation tend to have higher costs of capital, higher returns under the DCF method.

So you've got a little bit of a measurement problem there, but then when you turn to regulation, I would have to say honestly that there have been some moves in parts of the United States to relax things, but there is still the preponderance of the States are on historical test years, and some of them have some fairly stiff regulations on how you deal with historical test years.

As I say, there has been some relaxing. I know one of the States I work in has moved towards letting in information up to six months after the end of the historical test year. There are a few States that are future, but most of them still are historical.

There may be some areas where the United States is moving where Canada isn't on some of the issues such as decoupling of sales from revenues. Now, some utilities like it and some utilities don't. I think it's generally gas utilities like it and electric utilities are -- you know, some of them do and some of them don't.

I've seen a little more of that over the last few years. I think Alberta has taken a fairly large step in that direction, but with the weather normalization mechanism for ATCO Gas, that probably covers off about 80 or 90 percent of that decoupling risk on the gas company side.

So I would say there has been -- on the just pure regulatory side, there has been a little bit of a narrowing. I'm not sure I would take it as far as Ms. McShane has taken it.[123]

168. While U.S. utilities have benefited from the application of some of the attributes of Canadian regulation identified by Dr. Booth above and while the differences in regulatory practice between the U.S. and Canada may be narrower than they may have been at the time that the EUB last considered this matter, on the whole the Commission considers based on the evidence before it that these attributes are more pervasive in Canada and continue to suggest that Canadian utilities enjoy a more supportive regulatory environment and have less regulatory risk than their American counterparts. Further, the Commission considers that the reliance on historical test years and the DCF methodology[124] by the majority of U.S. regulators are further

[123] Transcript, page 3036, line 15 to page 3038, line 22.

[124] In response to a question from Commission Counsel Mr. Gaske stated at Transcript, page 1128, lines 12-16:

reasons for higher awarded ROEs in the United States. These conclusions are affirmed by the Commission's analysis with respect to credit metrics and bond ratings discussed below.

### 3.2.2.4 Credit Metrics and Bond Ratings

169. Mr. Coyne indicated that his research had shown that Canadian utilities generally have higher embedded debt costs and lower interest coverage ratios, despite having higher credit ratings compared to U.S. counterparts.[125] The higher embedded debt costs and lower interest coverage ratios flowed from the higher financial risk associated with the existing capital structures of Canadian utilities.[126] Mr. Coyne also noted that several utilities have insufficient financial metrics to support the credit rating that they had been given[127] and that some credit rating agencies maybe questioning the viability of some existing credit rating.[128] The ATCO Utilities conclude in their written evidence:

> ...the evidence is clear that the individual ATCO Utilities could not maintain A credit ratings on a stand alone basis. The evidence indicates that it is the financial profile of Alberta Power 2000 which is the force behind the credit ratings of CU Inc. and which subsidizes the Utilities and thereby the financial risk of CU Inc.[129]

170. The concern about higher risk and shaky credit ratings for Canadian utilities was challenged by the interveners. In his opening statement, Dr. Safir summarized the differences in risk in the following manner:

> No one denies that allowed returns in Canada are below those awarded by US regulators, but it is simply inaccurate to infer from this that Canadian utilities do not receive returns commensurate with the risks that they face. The Canadian regulatory structure is simply more committed to insulating Canadian utilities from market forces. It provides more protective regulatory oversight. As a result, allowed returns in Canada should be lower than those in the United States.
>
> You have also heard that the basic regulatory model is similar in the United States and Canada. I would agree with that. However, it is important to realize that the application of this general regulatory model differs substantially between the two countries. The US system is more "hands off" at the federal level. It is more fragmented at the state level, and it is more experimental at both levels. These differences manifest themselves in straight forward and readily observable differences in the financial circumstances of Canadian and US utilities.
>
> You don't need to be a rocket scientist, you don't need to be a finance professor, and you don't even need to be an economist to notice these differences. One obvious one is the credit ratings afforded to Canadian utilities compared to US utilities. On average, Canadian utilities receive higher credit ratings than their US counterparts. This is exactly what you would expect if Canadian utilities faced lower business risks.[130]

"In the regulatory arena, in the United States before the various federal and state commissions, the DCF method is overwhelmingly favoured. In Canada, it's overwhelmingly not favoured. The capital asset pricing model seems to hold greater favour in Canada."

125 Written Evidence of Mr. Coyne, Exhibit 50.01, Section 3, page 49.
126 Written Evidence of Mr. Coyne, Exhibit 50.01, Section 3, page 49 and 51.
127 Written Evidence of Mr. Coyne, Exhibit 50.01, Section 3, page 71.
128 Written Evidence of Mr. Coyne, Exhibit 50.01, Section 3, page 55.
129 Written Evidence of the ATCO Utilities, Exhibit 50.01, Section 1, page 6.
130 Transcript, page 3153, line 21 to page 3154, line 9.

The companies are the ones that generate that process. And they are the ones that go to the regulators and say: We would like to do this, that, and the other thing, as opposed to the regulator saying: You will do this, that and the other thing. So those are two of the big differences that I see.[145]

187. The Commission also notes the following exchange between Dr. Vander Weide and Commission Counsel with respect to this matter:

Q. ...Sir, starting at page 14 in question 27 and over to the top of page 15 you discuss your views that the risk of investing in electric and natural gas utilities is approximately the same in the US and Canada. You also make this point on page 34 when discussing the applicable common equity ratios. You point to the use of common technologies, similar economics, common cost of service regulation as support for your conclusions. You also dismiss the impact of deferral accounts in Canada suggesting that their impact is primarily on short term business risk which is more than offset by the financial risk Canadian utilities face because of lower common equity ratios.

Have I summarized your position correctly, sir?

A. Yes, and I would point out that I take a cut -- I make several comments about the risk and those are certainly some of those. I also, as I indicated yesterday in cross-examination, gave a more detailed analysis of the risks in response to several interrogatories, and I'm trying to find out which one it is.

Q. Sir, I wasn't trying to capture every nuance of what you were suggesting but to capture the general flavour of what you're trying --

A. Okay. The other place where I discuss the risks in more detail is in response to CAPP 003.

Q. Thank you, sir. Sir, if Canadian U.S. utilities have similar business risk but different financial risk, wouldn't you have Canadian utilities to have lower credit ratings than comparable utilities in the United States?

A. I'm looking at the question again. I'm not a credit rating expert, so it's difficult for me to comment on what credit ratings I would expect them to have, with the same degree of understanding as say a Susan Abbott would who has a lot of years of experience working for credit rating agencies.

Based on the financial metrics alone, I would -- I am somewhat surprised that the Canadian utilities have slightly higher credit ratings than the US utilities because the financial metrics are quite a bit lower even for what I consider similar businesses. I don't know how to explain that, I'm just surprised at it, but I don't know how to explain it.[146]

### 3.2.3 Conclusions with Respect to Relative Risk and the Use of U.S. Data on Allowed Returns and Market Returns in Determining a Fair Return for Alberta Utilities

188. The Commission has characterized the fair return standard as three criteria or factors to be considered by the Commission when applying its judgment in determining the appropriate weighting to be given to the evidence before it in arriving at a fair return. In undertaking this effort, the Commission must assess the tools available to it and determine which ones are best suited to the purpose. The question that this part of the Decision has tried to address is: should U.S. data on allowed and market returns for U.S. utilities be considered in determining the fair return for Alberta utilities?

145 Transcript, page 330, line 3 to page 331, line 25.

146 Transcript, page 2157, line 9 to page 2158, page 25.

189. The Commission has had to assess a great deal of evidence with respect to the comparability of awarded returns for utilities in the United States. The utilities urged the Commission to consider the rates of return awarded by U.S. regulators on the basis that the risks faced by investors in utilities in Canada are comparable, if not higher than they are in the United States. If the risks are comparable for a proxy group of U.S. utilities then the awarded returns on that proxy group should be considered as a means of gauging the comparable return available to investors, the returns needed by Alberta utilities to attract investment and the returns required in order to maintain the financial integrity of Alberta utilities. Therefore, returns awarded by U.S. regulators should be used by the Commission in determining the fair rate of return for Alberta utilities. Canadian utilities must compete for capital from investors who are free to invest their capital where it will provide the highest return on comparable risk. Interveners have submitted that the regulatory risk and therefore the total business risk of U.S. utilities is not comparable to Alberta utilities and accordingly, the allowed returns on U.S. utilities should not be considered by the Commission.

190. In the sections above the Commission has reviewed the evidence relating to the comparability of risk and the use of U.S. data on allowed returns. For the reasons stated above, the Commission has determined to exclude return information on FERC regulated utilities. With respect to U.S. data on allowed returns for natural gas and electric LDCs and other state regulated utilities, the Commission finds, based on the evidence and analysis referred to above, that the regulatory risk faced by these U.S. utilities in general remain materially higher than the regulatory risk of Alberta utilities. As a consequence, the returns awarded by U.S. regulators for U.S. LDCs would be expected to reflect this materially higher level of risk leading the Commission to conclude that U.S. allowed returns should not be used in determining a fair return for Alberta utilities.

191. The Commission also appreciates the significance of investor perceptions of regulatory risk and to the extent U.S. utilities may be perceived to be riskier than Canadian utilities it will impact the return expectation of equity investors. The perception of risk of equity investors was discussed in the following exchange between the Chair and Dr. Vilbert:

> Q. .... If the perceived risk of Canadian utilities is lower than the perceived risk of American utilities, then the perceived potential for default is lower in Canada, which means that the perceived probability of the equity holders being stuck for the remainder is lower; is that right?
> A. DR. VILBERT: I think I followed the full train of what you said, and I think I also agree with it. There's a bunch of "ifs" in your hypothesis.[147]

192. Any discussion of allowed returns must necessarily consider both ROE and capital structure in assessing the comparability of utility returns in the U.S. and Canada. In this regard the Commission notes the following discussion between Ms. McShane and Commission Counsel:

> Q. Thank you, ma'am, but I'm just trying to understand whether or not the fact that management selects the capital structure that's then approved by the utility for U.S. utilities could be one influencing factor as to why common equity ratios are as high as they are and they have not come down with the absolute reduction in risk.

[147] Transcript, page 2440, lines 15-22.

> A. MS. McSHANE: Well, they're still within the ranges of what the guidelines are for their rating in their industries.
> Q. And, ma'am, do you think, again, could it be one influencing factor as to when you compare ROE or capital structure in Canada versus United States that because management selects the capital structure for U.S. utilities that it may be influenced to be higher in the United States as compared to having the regulator deem it historically in Canada? Is that one potential influencing factor to explain the differences?
> A. MS. McSHANE: I think the simple answer is yes. The deemed capital structures in Canada are lower than what they would be if management had more flexibility to choose them themselves.[148]

193. Ms. McShane's view that the equity ratio in the U.S. is likely higher as a result of the ability of management in certain U.S. jurisdictions to set the capital structure within a range acceptable to the regulator is a further differentiating point between regulation of U.S. and Canadian utilities and an indication that allowed capital structures for U.S. utilities should not be held up as representative of the capital structures required by Canadian utilities in order to satisfy the fair return standard.

194. The record does not support a finding by the Commission that allowed returns on U.S. utilities should be considered as evidence of comparable returns on investment, returns necessary to attract capital or returns required to maintain the financial integrity of Alberta utilities. Higher ROE and capital structures for U.S. utilities will inevitability translate into higher earnings for U.S. utilities. However, higher earnings for U.S. utilities does not translate into a denial of a fair return to Alberta utilities when the underlying risks of utilities in the U.S. and Alberta have been determined by this Commission to be materially different. The fair return standard requires the Commission to grant a utility as large a return on the capital invested as it would receive if it were investing an equal amount in an alternative investment of comparable risk.

195. Significantly, the Commission's finding on the comparability of risk and allowed returns between Alberta and U.S. utilities is supported, as referred to above, by expert testimony offered by some of the witnesses appearing on behalf of utilities in this proceeding and by recent findings by the FERC. Accordingly, U.S. data on allowed returns will not be considered by the Commission in determining a fair return for Alberta utilities.

196. Additionally, the Commission observes that allowed utility returns are not returns available to be captured by investors generally. During the hearing, Mr. Coyne was asked by Commissioner Lyttle about the distinction between the availability of allowed rates of return to investors as follows:

> So I have a problem with your fairness deficit because I can't really say that I can invest here versus I can invest there. your fairness deficit speaks about ROEs that are awarded by Board, but that's really not reflected in the ending market values except to determine earnings on those specific years. How much weight can I put on a fairness deficit where a lot of different things impact earnings?
> A. MR. COYNE: Good question. I agree with you. You can't buy --you, as an individual investor, can't really buy either of those. You have -- but this really relates to the awarded ROE, of course, for the utility so this is what the regulatory body is granting the original investor in this capital their return for continuing to have that capital invested in that franchise. That's right. Individual investors don't see this. What they

[148] Transcript, page 1747, line 13 to page 1748, line 8.

> see is the result of this as reflected through the marketplace with all of its other influences. This, of course, is an important driver because if you are a regulated utility, that is where your income comes from. It's that applied to your book value.

197. As noted in the *Northwestern Utilities* a fair return must allow a utility the opportunity to recover a return on capital invested as it would receive investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the utility. None of the original equity investor, a subsequent investor or a prospective utility equity investor can take its invested capital, or the capital it proposes to invest in one utility, and redeploy it to an investment in another utility of comparable risk (where a pure play utility investment is available) unless it is prepared to invest at market prices. The existing or prospective equity investor in one utility cannot take its capital and invest it in another utility at a price equal to the underlying book value of that other utility's assets where the market to book ratio is greater than one. Consequently, even if the Commission had determined that U.S. utilities were utilities of comparable risk to Alberta utilities, where the market to book ratio of a U.S. utility is greater than one, an investor in securities of that utility at market prices will not receive a return on its investment equal to the return allowed by that utility's regulator. Rather, an equity investor's total return on an investment made at market prices (putting aside foreign exchange risk and tax implications of any cross-border investments) will be a function of dividend policy and share price required by, or set in the market in light of the market's perception of the riskiness of the investment. Financial markets react quickly to adjust prices so that investors receive similar expected (risk adjusted) rates of return from all the various alternative investments. Dr. Kryzanowski remarked on this result in response to a question from Commission Counsel:

> Q. And having gone through all those adjustments, even after those adjustments, is the stipulated return, for example, 12 percent on 50 percent common equity, is that even available to an investor, given that they have to pay market price to obtain the investment in the first place?
> A. DR. KRYZANOWSKI: Remember that that's an ROE, and an ROE is an accounting type of rate of return. Basically what you're interested in is market-based returns. So market prices will adjust to reflect the ROEs.[149]

198. Dr. Booth noted the following in an exchange with Commission Counsel:

> Q. Shouldn't, then, the returns on US utilities be a factor that this Commission should be very careful in terms of considering, in weighing the overall options that are available for Canadian investors?
> A. DR. BOOTH: No, because those returns that are allowed in the United States are factored into the prices of the utility holding companies in the United States. So the only way Canadians can access those rate of return is by paying the market price, and Canadian investors are going to look at that and say well, they've got to say 11, 12, percent rate of return but I'm having to pay two, three times book value and I'm exposed to the bigger regulatory risk.[150]

199. The Commission considers that while allowed returns awarded to selected proxy groups of utilities in the United States may be relevant in informing the Commission of how other regulators have assessed the fair return for utilities within their respective jurisdictions, allowed

[149] Transcript, page 3016, lines 3-11.
[150] Transcript, page 3395, lines 1-12.

returns cannot, in of themselves, be determinative of what a fair return for Alberta utilities should be given the inability of the investor to obtain the allowed return directly in the market.

200. The Commission considers that it must make a distinction between utility returns awarded by U.S. regulators and expected market based returns for U.S. utilities when considering the use of U.S. data in determining a fair return for Alberta utilities. Allowed returns, including both ROE and capital structure, are determined by a regulator after considering a number of factors including relevant overall factors like the applicable legislation and case law and individual factors that are specific to the utility, like the business risk of the utility. Also as noted above, the capital structure for U.S. utilities is frequently determined by management within a range acceptable to the regulator. The Commission has determined that returns awarded by U.S. regulators cannot be directly used in determining a fair return for Alberta utilities for the reasons provided above. Properly determined, however, expected market based returns in respect of a particular industry segment are a present reflection of the future return expectations of prospective investors given the perceived risk of that industry segment and the economy as a whole. The share price of the equity or the premium demanded on the sale of a corporate bond will adjust to meet these risk-adjusted investor expectations. Accordingly, expected market determined returns for U.S. utilities may be used on a market risk-adjusted basis in assessing a fair return for Alberta utilities, provided there is sufficient evidence to derive those expected market determined returns.

201. The Commission's conclusions with respect to the use of allowed returns as opposed to expected market based returns appears to be supported by the following exchange between the Chair and Dr. Vilbert, expert witness for AltaGas:

> Does this all come down to just let's do what the Americans do or is there something more for us to do here?
> DR. VILBERT: I think the short answer is no, I don't think that doing just what the Americans do is the right answer; and actually as I mentioned earlier, I've testified a lot in Canada and I've testified a lot in the United States and I think I heard Dr. Vander Weide say, yesterday, that cost of capital proceedings in the States take one to two days, whereas in Canada it's a longer process. I will also say that I prepare a lot harder when I testify in Canada than I do when I testify in the States because the questions are much more theoretical, they're much deeper questions. So in many ways, I think -- you know, it sounds like I'm being overly praising and I don't mean it to sound that way to sound that way, I'm just saying the Canadian regulatory process is pretty good and I think people, here, really are trying to get to the answer. I do believe, however, that the evidence from the States, particularly the sample companies from the States, has information to provide. I'm not as enamored of the idea of looking at the regulatory allowances in the States and saying that that should be some sort of a benchmark for you. It's certainly information, but I prefer, as a cost of capital expert, to rely on what the market is telling me as opposed to what other regulators are telling me. I do believe that the US market information is relevant to your deliberations and that that's one of the things that I think the NEB decision was positive about. It said look, let's look at the market information and the US companies provide us some information in that regard. After all, there are probably 15 to 30 gas LDC companies in the United States and there are substantially fewer than that in Canada. So that's a sample of companies you should access. But following -- not that you would – but following just slavishly along to what the Americans are doing, that doesn't seem to make any sense to me, particularly when it comes to allowed rates of return. You've got to consider the risks and so forth on your own. I do think it is a piece of evidence, though, when it comes to comparability the

> utilities in the States are being allowed more rate of return, higher rate of return on a higher equity thickness than their contemporaries in Canada.[151]

202. The Commission also finds support for its conclusions with respect to the use of expected market based returns rather than returns awarded by U.S. regulators in the following extract from a discussion between Dr. Vander Weide and the Chair:

> Well, in the US if one regulator looks just at what other regulators are offering, there is a circularity involved there. Rather than just looking at the -- cost of equity is determined in the marketplace. And let me give an example. Let's take Illinois versus California, say, and let's suppose the regulator in Illinois kind of ignores the market evidence and says "Let me just look at what the California regulators are doing and give the same rate of return as the California regulators." That would be circular, and I don't think anyone is suggesting that one ought to ignore the market evidence on the fair rate of return.[152]

203. In the above sections of this Decision the Commission has determined that sample proxy groups including U.S. utilities provided in evidence do have comparable business risk other than regulatory risk and that expected market determined returns in respect of these utilities may be informative to the Commission in determining a fair rate of return for Alberta utilities. Analyzing market based returns for U.S. utilities may be particular significant given the dirty window concerns with using data relating to Canadian holding companies discussed above (a concern also applicable to the U.S. data) and the circularity involved in setting allowed returns through a comparison to Canadian utilities whose returns have been set through a formulistic adjustment mechanism. As pointed out by Mr. Coyne and referred to above "[t]o evaluate the fairness of those ROE awards by looking to other Canadian utilities is analogous to looking in the mirror to compare your appearance to the reflection's."[153]

204. The Commission also notes the following comments of Dr. Vander Weide with respect to market based data on U.S. utilities:

> As discussed in my original filed evidence in this proceeding, there are several advantages to using U.S. utilities groups as comparables for the purpose of estimating the cost of equity for Canadian utilities. First, U.S. utilities groups include a significantly larger sample of companies with traditional utility operations than available Canadian utility groups. Second, reasonable estimates of expected growth rates are available for U.S. utilities, whereas the same data are not available for Canadian utilities. Third, reliable historical risk premium data for U.S. utilities are available for a much greater length of time than for Canadian utilities.[154]

205. In subsequent sections of this Decision the Commission will review the market based return data available on the record in respect of the sample U.S. utility proxy groups and employ this data in its CAPM and DCF determinations.

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151 Transcript, page 2430, line 11 to page 2432, line 8.
152 Transcript, page 2254, lines 8-19.
153 Written Evidence of Mr. Coyne, Exhibit 50.01, Section 3, page 41.
154 AUC-Vander Weide-011(b), Exhibit 263.01.

217. The Board determined that its approach of adopting a common ROE and adjusting for differences in risk by adjusting capital structures recognizes the impact of leverage on the cost of equity and adjusts for differing investment risks. Decision 2004-052 stated that " … a common ROE approach can accommodate these differences, by adjusting for any material differences in investment risk that would otherwise occur, through an adjustment to the capital structure, or, in exceptional circumstances, through a utility-specific adjustment to the common ROE."[163]

218. Despite some reservations respecting the use of an annual adjustment formula, most parties were not opposed to the Commission adopting the Board's approach of establishing a generic ROE for all the utilities and adjusting the equity ratios of individual companies to account for individual risk. Indeed, all the companies, with the exception of the ATCO Utilities, requested the same ROE of 11 percent and differed only in their debt to equity ratio proposals.

219. The ATCO Utilities requested a range of ROEs from 10.5 percent to 12 percent on a variety of proposed company-specific capital structures. ATCO preferred that the Commission approve an ROE and capital structure individually for each ATCO utility and then allow for the ROE and capital structure to be adjusted, as required, at the time of each company's general tariff applications. Alternatively, ATCO argued that, following approval of the individual ROE proposals for each ATCO utility, "[r]esetting the capital structures to the ATCO Utilities' recommendations, and revising the adjustment formula to ensure changes in comparable returns can be tracked over time, provides greater assurance that a new Formula can withstand the challenge of consistently providing a Fair Return in the future."[164]

220. The Commission agrees with the Board that "implementation of a generic approach is in the public interest"[165] because a generic approach improves efficiency of the regulatory process in Alberta, provides for greater consistency among utilities, and greater certainty and predictability of utility returns. Administrative efficiency in dealing with cost of capital evidence in rate proceedings was clearly an impetus for the Board and parties to consider a generic ROE formula approach and a single proceeding for setting capital structure for all utilities. The Commission considers that the proliferation of regulated companies caused by electric and gas deregulation, unbundling, and corporate reorganizations that influenced the Board to adopt a generic approach remains a compelling reason to continue with that approach.

221. Consequently, in this Decision, the Commission will approve a single generic ROE to be applied uniformly to all the utilities, and will adjust for any differences in risk among the utilities by adjusting their individual equity ratios.

# 5 2009 RETURN ON EQUITY

## 5.1 Introduction

222. To satisfy the fair return standard, the Commission is required to determine a fair return on equity for the utilities. The Commission was presented with a significant body of evidence on the tests to be considered when determining the fair ROE for 2009, a number of opinions on the proper methodology to be employed for many of the tests and, as a result, a wide range of proposed ROEs. Briefly, the record of the proceeding included evidence to support ROE

163 Decision 2004-052, page 14.
164 ATCO Argument, Exhibit 390.02, page 112.
165 Decision 2004-052, page 11.

estimates based on the Capital Asset Pricing Model (CAPM), the Discounted Cash Flow Model (DCF), the comparable earnings test, ROE awards by U.S. regulators, ROE awards by Canadian regulators, market- or price-to-book values, returns on high grade bonds, returns arising from negotiated settlements, and the return expectations from pension and investment managers. In addition, the Commission heard that specific adjustments to ROE might be required for some utilities. On the strength of this evidence, the Commission was presented with the following recommended ROEs for the utilities.[166]

**Table 6. Summary of ROE Recommendations[167]**

| | 2009 Formula Based (%) | Recommended by Utility[168] (%) | Recommended by UCA[169] (K&R) (%) | Recommended by CAPP[170] (Booth) (%) |
|---|---|---|---|---|
| **Electric and Gas Transmission** | | | | |
| ATCO Electric TFO | 8.61 | 10.5 | 7.9 | 7.25 |
| AltaLink | 8.61 | 11 | 7.9 | 7.25 |
| ENMAX TFO | 8.61 | 11 | 7.9 | 7.25 |
| EPCOR TFO | 8.61 | 11 | 7.9 | 7.25 |
| ATCO Pipelines | 8.61 | 12 | 7.9 | 7.25 |
| **Electric and Gas Distribution** | | | | |
| ATCO Electric DISCO | 8.61 | 10.6 | 7.9 | 7.25 |
| ENMAX DISCO | 8.61 | 11 | 7.9 | 7.25 |
| EPCOR DISCO | 8.61 | 11 | 7.9 | 7.25 |
| ATCO Gas | 8.61 | 11 | 7.9 | 7.25 |
| FortisAlberta | 8.61 | 11 | 7.9 | 7.25 |
| AltaGas | 8.61 | 11 | 7.9 | 7.25 |
| **Retailers** | | | | |
| EEAI | 8.61 | 11 | 7.9 | 7.25 |

## 5.2 Capital Asset Pricing Model

223. The capital asset pricing model is a well-accepted and theoretically-grounded economic model for valuing securities based on the relationship between non-diversifiable risk and expected return. CAPM is based on the principle that investors need to be compensated in two ways; for the time value of money and for risk. In the model, the time value of money is represented by the rate that compensates the investor for placing money in a risk-free investment over a period of time (the risk-free rate). The second part of the model considers risk and estimates the compensation that the investor needs for taking on the risk that the expected return will not be realized. This element of risk is calculated by taking a risk measure (beta) based on the statistical relationship between the historical returns for the investment security relative to the historical returns for the market as a whole, over time. Beta is a risk measure that describes how sensitive the expected return of a security is to the market. Hence, CAPM calculates the expected return for a security as the rate of return on a risk free security plus a risk premium.

166 The 2009 formula-based calculation is also shown.

167 The utilities' and interveners' ROE recommendations were made in conjunction with their equity ratio recommendations.

168 ATCO Evidence, Exhibit 50.01, page 5. (Also in ATCO Argument, Page 4), ENMAX Evidence, Exhibit 55.01, page 6, Vander Weide Joint Evidence, Exhibit 57.04, page 36, Vilbert AUI Evidence, Exhibit 58.02, page 24.

169 Evidence of Drs. Kryzanowski and Roberts, Exhibit 179.02, page 9.

170 Booth Revised Evidence, Exhibit 292.03, pages 3, 86 and 112.

224. Dr. Booth explained the use of CAPM in his evidence as follows.

> Why the CAPM is so widely used is because it is intuitively correct. It captures two of the major "laws' of finance: the time value of money and the risk value of money…the time value of money is captured in the long Canada bond yield as the risk free rate. The risk value of money is captured in the market risk premium, which anchors an individual firm's risk. As long as the market risk premium is approximately correct the estimate will be in the right "ball-park." Where the CAPM gets controversial is in the beta coefficient; since risk is constantly changing so too are beta coefficients. This sometimes casts doubt on the model as people find it difficult to understand why betas change. Further it also makes testing the model incredibly difficult. However, the CAPM measures the right thing: which is how much does a security add to the risk of a diversified portfolio, which is the central idea of modern portfolio theory.[171]

225. Evidence to support proposed ROEs based on an application of CAPM was provided by Dr. Booth, Drs. Kryzanowski and Roberts, Mr. Coyne, and Dr. Vilbert. Dr. Vander Weide did not provide a CAPM estimate but he did propose that the appropriate beta for utilities is 0.93, based on data from the U.S. market.[172]

226. The following table sets out the recommended individual CAPM components and resulting ROE levels for each of the experts that presented evidence on CAPM.

[171] Booth Revised Evidence, Exhibit 292.03, page 70, lines 14-24.

[172] Transcript, page 2173, line 17 to page 2174, line 12 and Dr. Vander Weide Rebuttal Evidence, Exhibit 282.01, page 25.

## Table 7. CAPM Recommendations

| Expert Witness | Risk-free Rate (%) | MERP (%) | Market Return | Beta | Utility Risk Premium (%) | Flotation Allowance (%) | ROE (%) |
|---|---|---|---|---|---|---|---|
| Dr. Booth | 4.25[173] | 5.0[174] | 9.25 | 0.50[175] | 2.5[176] | 0.50[177] | 7.25[178] |
| Drs. Kryzanowski & Roberts[179] | 4.75 | 5.1 | 9.85 | 0.52 | 2.65 | 0.50 | 7.90 |
| Mr. Coyne U.S. Gas DCs[180] | 4.44 | 6.25[181] | 10.69 | 0.80 | 5.0 | 0.50 | 9.95 |
| Mr. Coyne U.S. Elec. DC | 4.44 | 6.25 | 10.69 | 0.81 | 5.1 | 0.50 | 10.0 |
| Mr. Coyne N.A. Gas Trans | 4.32 | 6.25 | 10.57 | 0.90 | 5.6 | 0.50 | 10.47 |
| Mr. Coyne Canadian Utilities | 4.13[182] | 6.25 | 10.38 | 0.72 | 4.3 | 0.50 | 9.14 |
| Dr. Vilbert Canadian Utilities[183] | 4.5 | 5.75 | 10.25 | 0.63 | 3.62 | 0.50 | 8.6 |
| Dr. Vilbert U.S. Gas DCs[184] | 4.5 | 5.75 | 10.25 | 0.78 | 4.49 | 0.50 | 9.5 |
| Dr. Vilbert U.S. MLPs[185] | 4.5 | 5.75 | 10.25 | 0.57 | 3.28 | 0.50 | 7.9 |

227. Dr. Booth based his CAPM analysis on Canadian data only, as did Drs. Kryzanowski and Roberts. Mr. Coyne provided multiple CAPM analyses based on U.S. and Canadian data, as did Dr. Vilbert. With respect to Dr. Vilbert's CAPM analysis for his U.S. proxy groups, the Commission will not consider his analysis of Master Limited Partnership (MLP) pipelines. Dr. Vilbert used his MLP pipeline proxy group to derive a recommended ROE for NGTL. Now that the Commission is no longer required to establish a fair return for NGTL, the Commission finds that this proxy group is not representative of the companies at issue in this proceeding. In addition, the Commission observes that Mr. Coyne, on behalf of the ATCO Utilities (including ATCO Pipelines) did not include MLP pipelines in his proxy groups. Finally, the MLPs have structural differences and investor tax implications which differentiate them from most Alberta utilities.

173 Booth Revised Evidence, Exhibit 292.03, page 18.
174 Booth Revised Evidence, Exhibit 292.03, page 82, Market Risk Premium higher than the experienced premium over almost any period but accounts for the unexpectedly high returns on bonds in recent decades.
175 Booth Revised Evidence, Exhibit 292.03, pages 79 and 82.
176 Booth Revised Evidence, Exhibit 292.03, page 82 (and 5% times 0.50 = 2.5%).
177 Booth Revised Evidence, Exhibit 292.03, page 86.
178 Booth Revised Evidence, Exhibit 292.03, page 86.
179 Exhibit 179.02, Evidence of Drs. Kryzanowski and Roberts, page 9.
180 Exhibit 50.01, Evidence of James M. Coyne, Table JMC-05.
181 Exhibit 50.01, Evidence of James M. Coyne, pages 29-30. Market risk premium based on the average of the experienced market risk premium of 7.1 percent in the U.S. from 1926 to 2007 and 5.4 percent in Canada from 1936-2007.
182 Exhibit 50.01, Evidence of James M. Coyne, page 27, based on October 2008 Consensus Forecasts of the 10-year rate plus the September 2008 average spread between 10-year and 30-year government of Canada bonds.
183 Exhibit 52.02, NGTL Evidence, Dr. Vilbert. Table MJV-10.
184 Exhibit 52.02, NGTL Evidence, Dr. Vilbert. Table MJV-20.
185 Exhibit 52.02, NGTL Evidence, Dr. Vilbert. Table MJV-26.

228. In considering the evidence on CAPM, the Commission reviewed the remaining proposals on the individual components of CAPM, as well as the overall ROE levels based on the CAPM approach.

### 5.2.1 Risk-Free Rate

229. The CAPM analysis starts from a forecast of the risk-free rate. Parties differed on their recommended forecast of the risk-free rate. Dr. Booth based his forecast on ten-year long Canada bond yields forecasted by Consensus Economics Inc. and added 0.89 percent for the current spread between the thirty and ten year bond. This resulted in a 4.00 percent forecast to which he added 0.25 percent based on his judgment that the economy will recover more quickly which will cause interest rates to increase. He submitted that his resulting 4.25 percent estimate "is more in line with that of the Bank of Canada."[186] Given that Dr. Booth's forecast aligns with that of the Bank of Canada, the Commission accepts it as a reasonable forecast.

230. Drs. Kryzanowski and Roberts based their forecast of the risk-free rate on the long Canada yield of 4.36 percent adopted by the National Energy Board, which was based upon the Consensus forecast, in setting its allowed ROE for 2009,[187] but added 40 basis points "to normalize this yield for the effects of the current easy money monetary policy designed to stimulate economic activity due to the current global credit and economic crises."[188] They rounded their result to a forecast of 4.75 percent, noting that the same result was found in a recent forecast by TD Economics[189]. The Commission does not agree with the 40 basis point adjustment proposed by Drs. Kryzanowski and Roberts, because the TD Economics forecast is already included in the Consensus Economics Inc.

231. Mr. Coyne formed his forecast by taking the average of the 3-month-out and 12-month-out forecasts of the respective 10-year government bond yields, as reported in October 2008 by Consensus Economics Inc. and adding the daily average of the previous month's historical spread between 10-year and 30-year bonds. Mr. Coyne thereby predicted a risk free rate of 4.13 percent for Canada and 4.44 percent for the U.S.[190]

232. Dr. Vilbert also adopted a forecast from Consensus Economics Inc., using their August 2008 forecast of 10-year Canadian government bond yields of 4.3 percent. To this forecast for 10-year bonds, Dr. Vilbert added an additional 20 basis points to adjust the forecast to the average maturity of the long-term bond yields used to estimate the long-term market risk premium, yielding a long term risk free interest rate forecast of 4.5 percent for Canada. Dr. Vilbert used this forecast of the Canadian long term risk free rate for both his Canadian and U.S. CAPM analyses.

233. The Commission recognizes that, at the time these forecasts were made, the volatility in capital markets made it difficult to establish a consistent forecast and forecasts from all sources varied depending on the day, week or month that the forecast was calculated. The Commission considers that, at the time of the Proceeding, forecasts of the risk-free rate in the range of 4.13 percent to 4.50 percent were reasonable for the Canadian market.

186 Dr. Booth Revised Evidence, Exhibit 292.03, page 18.
187 Exhibit 179.02, page 186.
188 Drs. Kryzanowski and Roberts Evidence, Exhibit 179.02, Section 3.3.3.
189 Ibid.
190 Exhibit 50.01, Section 3.0, Evidence of Mr. Coyne, page 27 lines 8-19.

### 5.2.2 Market Equity Risk Premium

234. The next element of the CAPM analysis is the market equity risk premium (MERP). Parties recommended different market equity risk premiums.

235. Dr. Booth estimated the market equity risk premium at 5 percent noting that "[t]his is significantly higher than the experienced market risk premium earned in Canada over almost any time period, but takes into account the unexpected performance of the bond market, due to declining long Canada bond yields, and the reduction in risk in the bond market compared to a few years ago."[191] Dr. Booth demonstrated, upon reviewing historical data, that conditions in the bond market prior to 1956 were substantially different from what they had been since. In his view, this was due to an increase in bond market returns, commensurate with an increased risk in investing in government bonds, arising from government deficits and inflation. Consequently, he said, much of the drop in the market risk equity premium since 1956 was caused by an increase in the risk of investing in long Canada bonds, not by a decline in equity returns. With a reduction in government deficits since the mid 1990s, the yields on government bonds have declined and, by comparison, the market risk equity premium has increased.[192]

236. Drs. Kryzanowski and Roberts employed four methods to estimate the market equity risk premium, relying primarily on the first and using the remaining methods to confirm the findings from the first. They based their initial analysis on a blended average of the arithmetic and geometric mean market equity risk premiums for the time period from 1952 to 2008 because "the exclusive use of the arithmetic mean MERP results in an overstatement of the prospective MERP, and that the exclusive use of the geometric mean MERP results in an understatement of the prospective MERP."[193] This analysis yielded a market equity risk premium of 4.20 percent. Drs. Kryzanowski and Roberts then conducted a survey of Canadian and U.S. market equity risk premium estimates as reported in recent studies published in refereed journals. From this survey, they concluded that a forward-looking market equity risk premium for Canada is not more than 5.10 percent.[194] Their third estimate was based on the DCF estimation method, again concluding that a forward-looking market equity risk premium for Canada is not more than 5.10 percent. Finally, Drs. Kryzanowski and Roberts undertook a survey of knowledgeable professionals to confirm their estimate of the market equity risk premium. They concluded, again, that a forward-looking market equity risk premium for Canada is not more than 5.10 percent. On the basis of their findings from these four analytical methods, and a number of other "balancing" considerations discussed in their evidence, and further providing for an allowance for estimation error, they forecast a market equity risk premium of 5.10 percent for an "average-risk" utility for 2009.[195]

237. Mr. Coyne estimated the market equity risk premium as the mid-point of the long horizon equity risk premium data averaged over the longest period for which data were available from Morningstar Ibbotson for both the U.S. and Canada. The analysis for the U.S. data from 1926 to 2007 yielded a 7.10 percent market equity risk premium. The results for Canada from 1936 to 2007 yielded a market equity risk premium of 5.40 percent; and from 1939 to 2007, the U.S. Ibbotson data yielded a 5.80 percent market equity risk premium. Based on this analysis,

[191] Dr. Booth Revised Evidence, Exhibit 292.03, page 82.
[192] Dr. Booth Revised Evidence, Exhibit 292.03, page 81, line 18 to page 82, line 10.
[193] Drs. Kryzanowski and Roberts Evidence, Exhibit 179.02, Section 3.3.1.1.3.
[194] Drs. Kryzanowski and Roberts Evidence, Exhibit 179.02, Section 3.3.1.2.2.
[195] Drs. Kryzanowski and Roberts Evidence, Exhibit 179.02, Section 3.3.1.5.

Mr. Coyne selected 6.25 percent as his market equity risk premium, viewing the result as "an appropriate North American indicator."[196]

238. Dr. Vilbert argued that "it is likely that investors risk aversion increases during times of financial distress so that the MRP currently is higher than in the recent past."[197] He maintained his estimate from the previous National Energy Board proceeding (RH-1-2008), with support from "the latest academic evidence" including a recent paper on the worldwide premium,[198] and concluded that the market equity risk premium is 5.75 percent.

239. In the Commission's view, the 6.25 percent recommendation of Mr. Coyne is unreasonably high. Mr. Coyne estimated a "North American indicator" based on what appears to be an average of the U.S. and Canadian market equity risk premium figures from the Ibbotson data. The Commission does not agree that Mr. Coyne's "North American indicator" is sufficiently representative of the market equity risk premium in the Canadian investment market. The Commission also notes that Mr. Coyne's own analysis of the Canadian market equity risk premium, based on the Ibbotson data, yielded a market equity risk premium of 5.40 percent, which is similar to the findings of the other expert witnesses, which were in the range of 5.00 percent to 5.75 percent.

240. Accepting Dr. Vilbert's assertion that the market equity risk premium may currently be higher than in the past, a market equity risk premium of 5.75 may be warranted. Therefore, the Commission finds the range of 5.00 percent to 5.75 percent market equity risk premium to be reasonable.

### 5.2.3 Beta

241. The next element of the CAPM analysis is the beta. Beta is a statistical measure describing the relationship of a stock's return with that of the stock market as a whole. In the Commission's view, the proper beta to use is that which represents the relative risk of stand-alone Canadian utilities. This is the element of CAPM where the estimates of the expert witnesses diverged the most, providing a recommended range of 0.50 to 0.93.

242. Based on his analysis of the relative standard deviation of ROEs, recent standard beta estimates for utility holding companies, recent beta estimates for utility sub-indexes and a two-factor analysis of utility returns against the TSX composite return, Dr. Booth observed that there is no statistical evidence that the risk of Canadian utility holding companies for the last ten years has consistently been within the "normal" range of 0.40 to 0.60 experienced in the mid to late 1990s. He opined that this is because "normal market conditions are becoming unusual as capital markets seem to be jumping from one bubble to another."[199] He concluded, on the basis of judgment and a consideration that betas tend to revert to their long run average, that the beta range should be estimated at 0.45 to 0.55. For his CAPM analysis, Dr. Booth employed a beta estimate of 0.50, stating that he found "nothing in the recent risk measures to indicate that this risk ranking has changed in any substantial way."[200]

196 Exhibit 50.01, Section 3.0, Evidence of J. Coyne, page 29, line 31 to page 30, line 7.
197 Vilbert Evidence, Exhibit 58.02, page 24.
198 Ibid.
199 Dr. Booth Revised Evidence, Exhibit 292.03, pages 78-79.
200 Ibid. page 79.

243. Mr. Coyne used adjusted betas from Value Line and Bloomberg to develop his beta estimates. He argued for the use of adjusted betas on the grounds that "an individual company beta is more likely than not to move towards the market average of 1.00 over time" and "it is necessary to adjust forecasted betas toward 1.00 in an effort to improve forecasts."[201] [202]

244. Mr. Coyne calculated betas for four proxy groups, a U.S. Gas Distribution proxy group at 0.80, a U.S. Electric Distribution proxy group at 0.81, a Gas Pipeline group with a mix of Canadian and U.S. utilities at 0.90, and a Canadian proxy group at 0.72.[203]

245. Dr. Vilbert used three proxy groups to estimate betas, a Canadian utilities sample, a gas local distribution company sample with both Canadian and U.S. companies and a sample of Master Limited Partnership pipelines with both Canadian and U.S. companies. He calculated rolling beta estimates using monthly excess returns over the previous 60 months. Market returns were represented by either the S&P/TSX or the S&P 500 indices, as appropriate, and risk-free rates were taken as Canadian and U.S. 91-day T-bill returns, as appropriate, employing Value Line unadjusted betas for his Gas LDC and MLP pipeline samples and Bloomberg unadjusted betas for the Canadian sample.[204] For the reasons noted previously, the Commission did not consider Dr. Vilbert's analysis for MLP pipelines.

246. Dr. Vilbert modified his Canadian beta estimates by using adjusted betas, noting that the result of his initial analysis did not yield "an accurate measure of the relative risk of the sample companies in many of the periods."[205] He argued for adjusted betas because he considered his Canadian sample to be sensitive to interest rate changes and noting that "the 60-month betas for the Canadian Utilities sample are still increasing from their lows of the "tech bubble" period."[206] On the basis of this analysis including the adjustments, Dr. Vilbert recommended a beta for Canadian utilities of 0.63 but qualified his estimate as downward biased because "the period of turmoil in the market that resulted in low or negative beta estimates is still included in the estimation period."[207]

247. Drs. Kryzanowski and Roberts based their beta estimate on an analysis of 60 months of return data on actual market transactions for a sample of ten Canadian publicly traded utility holding companies.[208] Drs. Kryzanowski and Roberts calculated the average betas of 0.315 for the period 1992 to 2008, and 0.583 for 1990 to 1994. The means of the mean cross-sectional betas for the first five, middle five, and the last (most recent) five rolling five-year periods were 0.539, 0.150 and 0.255, respectively. They stated that there is no evidence that the normal tendency of this sample of utility betas is to revert back to a market beta of one and therefore, there is no justification for using non-standard (adjusted or inflated) betas.[209] On the basis of

201 Exhibit 50.01, Section 3.0, Coyne Evidence, page 28.
202 Mr. Coyne referenced studies by Blume to support his use of adjusted betas, the same references cited by Drs. Kryzanowski and Roberts in their explanation of the rationale for using adjusted betas.
203 Exhibit 50.01, Section 3.0, Coyne Evidence, page 15.
204 Vilbert Evidence, Exhibit 52.02, page 50.
205 Ibid. page 51.
206 Ibid. page 55.
207 Ibid. page 56.
208 Exhibit 179.04, Evidence of Drs. Kryzanowski and Roberts, Schedule 3.13.
209 Exhibit 179.02, Drs. Kryzanowski and Roberts, pages 178-180.

their analysis, they concluded that the rationales supporting the use of non-standard betas, as advocated by Mr. Coyne, are incorrect in a Canadian context.[210]

248. Drs. Kryzanowski and Roberts also found that the average correlation between utilities in their sample and the S&P/TSX Composite has declined substantially from the most distant five-year period to the more recent five-year period (0.495 versus 0.247), and is quite low at 0.263 when averaged over 15 rolling five-year periods. They concluded from this finding that "an average utility is now more desirable as an investment because of its enhanced potential for portfolio risk reduction. A greater potential for risk reduction leads to a reduction in an asset's own equity risk premium all else held equal. This reduction in the correlations between the returns of the utilities and the market also contributes to the reduction in the betas of the sample of utilities."[211] They also noted that "the adoption of adjustment mechanisms to automatically adjust ROE on a generic basis by various Canadian regulatory bodies has most likely contributed to this reduction in risk."[212]

249. In addition, Drs. Kryzanowski and Roberts calculated the standard deviation of returns for their sample of utility holding companies and Dr. Vilbert's sample, over rolling five-year periods. They concluded that there is no evidence that the total investment risks of their sample of Canadian utility holding companies or Dr. Vilbert's sample of five Canadian utility holding companies have increased since the last generic proceeding.[213] They recommended, on the basis of their several analyses, that a beta of 0.52 is appropriate and that this estimate is conservatively high, and provides sufficient coverage for any estimation errors.[214]

250. Finally, Dr. Vander Weide recommended a beta for utilities of 0.93, based on data from the U.S.,[215] but he did not provide an overall CAPM estimate.

251. The Commission is persuaded by the empirical analysis of Drs. Kryzanowski and Roberts that there is insufficient evidence to support the use of adjusted betas for Canadian utilities if the purpose of the adjustment is to adjust the beta towards one and therefore, beta should not be adjusted towards one. Therefore, the Commission rejects Mr. Coyne's beta results as unreasonably high, because he adjusted his beta estimates on the assumption that they would revert to 1.00. In other words, his analysis assumes that, in time, utilities would be as risky as the market as a whole.

252. Likewise, the Commission rejects Dr. Vander Weide's recommendation of 0.93 as unreasonably high, noting that it is based strictly on U.S. data. In this regard, the Commission is also mindful of Dr. Vilbert's assertion during cross examination when commenting on Dr. Vander Weide's beta estimate, that he had never encountered a Canadian utility beta that high.

> As I say, I can't get my betas to get anywhere near that high when I estimate them, not that I'm trying to make them high but they don't come out that high. And my sense is that

[210] Ibid. page 185.
[211] Ibid. page 181.
[212] Ibid.
[213] Ibid. page 182.
[214] Ibid. page 185
[215] Dr. Vander Weide Rebuttal Evidence, Exhibit 282.01, page 25 and Transcript, pages 2173 to 2174.

> regulated utilities are generally not quite that risky relative to the market, that a .65 is a relatively reasonable market estimate of what the beta should be.[216]

253. The Commission understands that estimating a beta for Canadian stand-alone utilities is difficult. The experts in this proceeding have employed a variety of techniques, data sets and considerable professional judgment in their beta proposals. Dr. Vilbert's comments with respect to the challenges of calculating a beta for Canadian utilities speaks to this challenge.

> ... the concern I do have is that it's been consistently difficult over the last ten years or so that I've been working in Canada to estimate the betas for your utility companies ... I bet you I've tried a dozen different ways to estimate the betas and I will tell you that from proceeding to proceeding, the method I think I've finally figured out how to capture the essence of the risk of these companies as likely as not doesn't work the next time.[217]

254. In the Commission's judgment, Dr. Booth's recommended beta of 0.50 represents a reasonable lower bound for beta for stand-alone Canadian utilities. The Commission recognizes that Dr. Vilbert's analysis was intended to modify his unadjusted Canadian sample results to account for his judgment that the unadjusted results were not adequately representative of forward looking expectations, which is consistent with Dr. Booth's rationale for adjusting his beta recommendation. The Commission finds Dr. Vilbert's Canadian beta estimate of 0.63 to be a reasonable upper bound for beta for stand-alone Canadian utilities. The Commission notes that the beta recommendation of Drs. Kryzanowski and Roberts falls within the range of 0.50 to 0.63 discussed above.

### 5.2.4 Flotation Allowance

255. The parties all agreed that a flotation allowance is normally included in the CAPM model to account for the administrative costs and issuance costs for the investment banker, any impact of under-pricing a new issue, and the potential for dilution. The CAPM calculations presented in the Proceeding and included in the Commission's Table 7 above include the usual regulatory convention of adding 0.50 percent to the CAPM estimate. The Commission agrees that a flotation allowance of 0.50 percent is warranted.

### 5.2.5 The Commission's Resulting CAPM Estimate

256. Applying its findings on the individual components of CAPM, the Commission calculates a range of CAPM ROE results for stand-alone Canadian utilities of 6.63 percent to 8.12 percent, without the flotation allowance. With a flotation allowance the Commission calculates a CAPM ROE range of 7.13 percent to 8.52 percent.

## 5.3 Discounted Cash Flow Model

257. The Discounted Cash Flow Model is used to estimate the cost of a company's common equity based on the expected dividend yield of the company's shares plus the expected future dividend growth rates. The DCF method calculates ROE as the rate of return that equates the estimated future stream of dividends with the current share price.

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216 Transcript, page 2424.
217 Transcript, page 2422.

258. Mr. Coyne states in his evidence:

> The DCF model evolves from the basic premise that investors will value a given investment according to the present value of its expected returns over time. This model is widely used in valuing entire companies by discounting the projected cash flows for the enterprise. When valuing the entire enterprise, financial analysts discount the future stream of free cash flows. When considering the common stock of a company, investors consider the future stream of dividends as cash flow from this investment (characterized as the Dividend Discount Model).[218]

259. Evidence to support proposed ROEs based on an application of the DCF model was provided by Mr. Coyne, Dr. Vilbert and Dr. Vander Weide.

260. The following table sets out the individual DCF components and resulting ROE levels for each of the parties that presented evidence on the DCF model. The Commission notes that, with the exception of Mr. Coyne, the experts did not include a 0.50 percent increment for flotation costs in their DCF analyses. The Commission considers that the DCF results should be adjusted to include flotation costs. As with the CAPM analysis, the Commission adjusts the DCF results to include a 0.50 percent flotation allowance.

**Table 8. Summary of DCF Estimates**

| Expert Witness | Dividend Yield | Stage 1 Growth Rate | Stage 2 (if applicable) Growth Rate | Indicated ROE (%) | Flotation Allowance (%) | ROE (%) |
|---|---|---|---|---|---|---|
| Dr. Vander Weide 30 U.S. Electric Companies | See Exhibit 8 | See Exhibit 8 | n.a. | 11.8 | 0.50 | 12.3 |
| Dr. Vander Weide 11 U.S. Natural Gas Companies | See Exhibit 9 | See Exhibit 9 | n.a. | 10.8 | 0.50 | 11.3 |
| Mr. Coyne[219] 6 U.S. Gas LDCs | 4.24% | 5.5% | n.a. | 9.74 | 0.50 | 10.24 |
| Mr. Coyne 6 U.S. Electric Dist. | 4.82% | 4.88% | n.a. | 9.70 | 0.50 | 10.20 |
| Mr. Coyne 5 North America Gas Transmission | 3.12% | 8.11% | n.a. | 11.23 | 0.50 | 11.73 |
| Mr. Coyne 5 Canadian Utilities | 3.87% | 6.41% | n.a. | 10.29 | 0.50 | 10.79 |
| Mr. Coyne Average | | | | 10.24 | 0.50 | 10.74 |
| Dr. Vilbert 5[220] Canadian Utilities[221] - single-stage | 3.42% | 6.24% | n.a. | 10.04 | 0.50 | 10.54 |
| Dr. Vilbert 5 Canadian Utilities[222] -multi-stage | 3.42% | See Schedule[223] | 4.1% | 8.38 | 0.50 | 8.88 |

218 Exhibit 50.01, Section 3.0, Evidence of J. Coyne, page 16, lines 9-15 .
219 Exhibit 50.01 ATCO, Coyne Evidence Schedule JMC-04, PDF pages 193-196 of 393.
220 Exhibit 52.02, Table MJV-6, Canadian Utilities, Emera, Enbridge, Fortis Inc., and TransCanada Corp.
221 Exhibit 52.02, Table MJV-6 panel A, and MJV-7 panel A.
222 Exhibit 52.02, Table MJV-6 panel B, and MJV-7 panel B.
223 This refers to Dr. Vilbert's Schedules in Exhibit 52.02.

| Expert Witness | Dividend Yield | Stage 1 Growth Rate | Stage 2 (if applicable) Growth Rate | Indicated ROE (%) | Flotation Allowance (%) | ROE (%) |
|---|---|---|---|---|---|---|
| Dr. Vilbert 11 U.S. Gas LDCs - single-stage | See Schedule | See Schedule | n.a. | 8.8 | 0.50 | 9.3 |
| Dr. Vilbert 11 U.S. Gas LDCs - multi-stage | See Schedule | See Schedule | 4.8% | 8.8 | 0.50 | 9.3 |
| Dr. Vilbert Subset of the 11 U.S. Gas LDCs - single-stage | See Schedule | See Schedule | n.a. | 8.3 | 0.50 | 8.8 |
| Dr. Vilbert Subset of the 11 U.S. Gas LDCs[224] - multi-stage | See Schedule | See Schedule | 4.8% | 8.5 | 0.50 | 9.0 |

261. Mr. Coyne applied the DCF model to the same set of proxy groups he used in his CAPM analysis. He calculated the current dividend yield for each company in each proxy group by dividing the annualized current dividend by the 90-day average stock price. Mr. Coyne argued that the 90-day average period was long enough to eliminate short-term trading volatility but still short enough to reflect recent value. This calculated dividend yield was increased by one-half of the assumed growth rate to reflect the expected growth in dividends over the coming year.[225] To these dividend yields, he applied a growth rate forecast based on forward-looking growth estimates from Value Line, Zacks Investment Research, Thomson First Call and Bloomberg for each of the proxy companies,[226] in some cases averaging the estimates where they were not available for specific companies, and adjusting for any outliers in the data.

262. To calculate his final DCF results, Mr. Coyne added the expected dividend yield to the average growth rate. He calculated a low DCF result by taking the lowest of the available growth rates for a given company plus the expected dividend yield for that anticipated level of growth and the high DCF result in the same manner. He then averaged the low, mean and high company-specific DCF results to obtain "unadjusted DCF results" for each proxy group. Finally, Mr. Coyne added a 50 basis point allowance for flotation, as he had with the CAPM model.

263. Mr. Coyne's DCF analysis yielded the following ROEs for each of his proxy groups.[227]

**Table 9. Summary of Mr. Coyne's DCF Analysis**

| Proxy Group | Low (%) | Mean (%) | High (%) |
|---|---|---|---|
| U.S. Natural Gas Distribution Utilities | 8.82 | 10.24 | 11.77 |
| U.S. Electric Distribution Utilities | 9.78 | 10.20 | 10.60 |
| Gas Transmission Pipelines | 10.14 | 11.73 | 13.38 |
| Canadian Utilities | 10.02 | 10.79 | 11.69 |
| **Average** | **9.69** | **10.74** | **11.77** |

224 Exhibit 52.02, Tables MJV-17 and 18.
225 Exhibit 50.01, Section 3.0, Coyne Evidence, page 98.
226 Ibid. page 99.
227 Exhibit 50.01, Section 3.0, Evidence of J. Coyne. page 26, line 22.

264. Mr. Coyne employed the results of his DCF analysis and his CAPM analysis to determine "the relative ranges of ROE for each sector." His remaining analyses were intended to corroborate his findings from these two methods.[228]

265. Dr. Vander Weide applied the DCF model to two proxy groups of Value Line U.S. gas and electric utilities. To establish his proxy groups, Dr. Vander Weide selected companies that paid dividends during every quarter and did not decrease dividends during any quarter of the previous two years; had at least three analysts included in the Institutional Investors Estimation Service mean growth forecasts; were not in the process of being acquired; had a Value Line Safety Rank of 1, 2, or 3; and had investment grade S&P bond ratings.

266. Dr. Vander Weide's DCF analysis for his proxy group of U.S. natural gas companies produced an ROE of 10.8 percent. His analysis for his proxy group of U.S. electric companies produced an ROE of 11.8 percent. Dr. Vander Weide calculated that the average DCF result for his comparable groups was 11.3 percent, and he concluded that the ROE for his comparable companies was 11.3 percent, before flotation.

267. Dr. Vilbert included multi-stage forms of the DCF model which allowed for varying dividend growth rates in the near term before assuming a perpetual growth rate, beginning in year eleven. He used the applicable forecast growth of GDP for his Canadian and U.S. analysis respectively as the long-term growth rate beyond year eleven.[229] Dr. Vilbert applied his DCF analysis to the same sample of proxy companies that he used for his CAPM analysis. His analysis, using his multi-stage approach to calculating the expected dividend growth rate, produced ROEs of between 9.0 percent and 9.3 percent for his U.S. proxy groups and 8.88 percent for his set of Canadian proxy companies, after flotation.

268. Drs. Kryzanowski and Roberts argued that implementing the DCF method at the individual utility level, as the utility experts had done, is fraught with implementation biases.[230] Among these alleged biases are problems with using analysts' "bottom-up" growth rate forecasts that may be optimistic. Dr. Booth also spoke to similar problems with estimating growth rates in DCF analyses, arguing that "it is generally accepted that analysts' earnings forecasts are biased high."[231] On the contrary, however, Mr. Coyne argued that "[w]hether growth rates are higher or lower than what is actually achieved is irrelevant to what we are measuring – investor expectations and the influence of those expectations on required returns."[232]

269. The Commission is concerned that many of the proxy companies used by the experts in their DCF analyses are holding companies that are engaged in significant unregulated activities and is also concerned with the potential upward bias in analysts' growth estimates. Nonetheless, the Commission considers that a multi-stage DCF analysis that adjusts the long run growth expectations to a reasonable level can provide some guidance to the Commission. The Commission will, therefore, consider the results of some of Dr. Vilbert's multi-stage DCF analyses in its deliberations, as further explained below.

228 Ibid. page 13.
229 Dr. Vilbert Evidence, Exhibit 52.02, page 37.
230 Drs. Kryzanowski and Roberts, Exhibit 179.02, page 263.
231 Dr. Booth Revised Evidence, Exhibit 292.03, Page 104
232 Exhibit 50.01, Section 3.0, Evidence of Mr. Coyne, page 30.

270. With respect to the analyses of Dr. Vander Weide and Mr. Coyne, the Commission considers that DCF growth estimates that exceed the expected growth in GDP over the long run are unrealistic, particularly for a stand-alone regulated utility. Dr. Vander Weide's DCF estimates assumed dividend growth rates that frequently exceeded the expected Canadian GDP nominal growth rate of 5 percent to 6 percent, including inflation.[233] Mr. Coyne's DCF analyses similarly forecast dividend growth rates that are, for all but one of his proxy groups, above the expected GDP nominal growth rate. For this reason, the Commission rejects the results of the DCF analyses of both Dr. Vander Weide and Mr. Coyne.

271. Dr. Vilbert provided DCF results for both a sample of Canadian utilities and a sample of U.S. gas utilities. He provided single-stage and multi-stage growth estimates in his DCF analyses. The Commission considers his multi-stage growth estimates, which employed a growth assumption of 4.1 percent beyond 11 years, to be informative. Dr. Vilbert's Canadian sample multi-stage DCF rate of return estimate was 8.38 percent before flotation. Dr. Vilbert's multi-stage DCF estimate, based on 11 U.S. gas utilities, was 8.8 percent before flotation.

272. In Dr. Vilbert's Canadian proxy sample, the unadjusted DCF results for Emera Inc., with holdings consisting of mostly regulated utilities, was 8.8 percent including a 0.50 percent flotation adjustment. Dr. Vilbert's unadjusted DCF result for Fortis Inc., with holdings that are largely Canadian regulated utilities, was 9.2 percent including a 0.50 percent flotation adjustment. Notwithstanding the concerns raised by Drs. Kryzanowski and Roberts with respect to the application of the DCF method to individual companies, the Commission is prepared to take into account the returns expected for these companies in its assessment of a fair return for Alberta utilities. In addition, the Commission recognizes that, in Dr. Vilbert's DCF analyses of both U.S. and Canadian utilities employing a multi-stage growth estimate, the calculated ROE is in the range of 8.9 percent to 9.3 percent, including 0.50 percent flotation.

273. Overall the Commission finds that the DCF results suggest a range of ROEs for Canadian stand-alone utilities of 8.8 percent to 9.3 percent, assuming that the equity ratio has been set to target a credit rating in the A range.

## 5.4 Comparable Earnings

274. The comparable earnings test examines the accounting returns of a company as a percentage of its book value. The ATCO expert witnesses provided comparable earnings for a proxy group of companies that, in their view, were comparable to Alberta stand-alone utilities. Comparable earnings evidence provided by Mr. Coyne and Ms. McShane showed a range of comparable earnings from 11.2 percent to 13.6 percent.

275. Dr. Booth included, in his evidence, Statistics Canada's estimated average accounting earnings for Corporate Canada, for the period from 1998 to 2007. This data showed an average accounting return of 9.1 percent for the period.

233 Exhibit 179.04, Schedule 3.8, Panel A.

276. The comparable earnings results are set out in Table 10, below.

**Table 10. Summary of Comparable Earnings Results**

| Expert Witness | Method | Sample Description | Comparable or Reference ROE |
|---|---|---|---|
| Mr. Coyne[234] | Achieved recent ROE on Canadian low risk industrials | 14 low risk companies all of which were in Consumer Products or Media segment | 13.6% |
| Dr. Booth | Past ROE on overall Equity Market | Statistics Canada ROE for Corporate Canada | 9.1%[235] |
| Ms. McShane[236] | Achieved ROEs of U.S. Electric Utilities | 29 U.S. Electric Utilities Rated A- or higher 49% average equity ratio | 12.4% average 11.6% median 2005-2007 |
| Ms. McShane[237] | Achieved ROEs of U.S. Gas Utilities | 14 U.S. Natural Gas Utilities Rated A- or higher 48% average equity ratio | 12.1% average 11.2% median 2005-2007 |

277. Mr. Coyne measured returns in relation to book value for a proxy group of assumed low risk industrial companies headquartered in Canada. Mr. Coyne used Globe Investor to compile a list of all publicly-traded media, consumer products, and utility holding companies in Canada. He considered these sectors "to represent industrial consumer staples with relatively stable demand and significant capitalization."[238] He obtained quarterly earnings per share data and quarterly return on common equity data for the trailing 12 months going back 5 years for all companies, and then selected only the companies with steady positive annual EPS and ROE for all years; and eliminated companies with a coefficient of variation for earnings per share of greater than 50 percent. This was intended to mimic the stable earnings of the utilities. He reported results that both included and excluded utility companies, recognizing the circularity arising from results that include utilities. The Commission included in the table above his sample that excluded utilities to avoid circularity.

278. Ms. McShane's ROE estimates were developed from two separate samples: all U.S natural gas utilities rated A- or higher and all U.S. electric utilities rated A- or higher. Ms. McShane's results for natural gas utilities were on average 12.1 percent. Her results for electric utilities were on average 12.4 percent. ATCO submitted that the evidence of Ms. McShane[239] demonstrated that A- rated U.S. utilities on average have achieved earnings higher than have been allowed by regulators in Canada and, to a greater extent, higher than the earnings of the ATCO Utilities.[240]

234 Exhibit 50.01, Section 3.0, Coyne Evidence, page 34 and Schedule JMC-07.
235 Booth Revised Evidence, Exhibit 292.03, page 28.
236 Exhibit 50.01, Section 4.0, McShane Evidence, Schedule 4.
237 Exhibit 50.01, Section 4.0, McShane Evidence, Schedule 5.
238 Exhibit 50.01, Section 3.0, Coyne Evidence. page 34.
239 Exhibit 279.01, McShane Rebuttal at pages 14-15.
240 ATCO Argument, Exhibit 390.02, page 92.

279. Drs. Kryzanowski and Roberts did not provide a comparable earnings test because they state that "it is of dubious scientific merit …and thus unsuitable for use in determining a fair ROE for a utility." They argued that there is neither any theoretical underpinning nor any empirical support for the comparable earnings method for estimating a regulated fair rate of return for a utility. In their view, "as an accounting-based measure, comparable earnings will only coincide with the investor's opportunity cost (required rate of return) by accident. There is no conceptual reason to expect that comparable earnings represent a rational expectation of an investor's desired rate of return from investing in the firm."[241]

280. In Decision 2004-052, the Board rejected the comparable earnings test results as a measure of return on a comparable investment.

> The CE [comparable earnings] test measures **actual** earnings on **actual book value** of comparable companies, which in the Board's view does not measure the return "*it* ***would*** *receive if it* ***were*** *investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise*" (emphasis added) (unless the securities were currently trading at book value).[242]

281. The Commission agrees with the Board that the comparable earnings test examines accounting earnings on book value for companies, but not returns actually available to, or required by investors in the market. In the Commission's view, because the comparable earnings test does not deal with returns available to investors in capital markets, it is not consistent with the comparable investment standard and is not a test upon which any weight should be placed. Consequently, the Commission will not consider the comparable earnings evidence.

### 5.5 Returns Awarded by Other Regulators

282. With respect to awarded returns for other Canadian utilities, a number of the utilities[243] argued that taking into consideration awards from regulators employing an adjustment mechanism similar to that used by the Commission would be circular. Accordingly, they recommended that the Commission place no weight on these awards. Mr. Coyne stated that:

> In Canada, the majority of utilities are bound by the same ROE formula, as are the utilities in Alberta, which is linked to the change in government bond yields. To evaluate the fairness of those ROE awards by looking to other Canadian utilities is analogous to looking in the mirror to compare your appearance to the reflection's. The potential for circularity of such a benchmarking analysis renders it, for the most part, meaningless as an independent source of comparability.[244]

283. CAPP took the position that awards by other regulators, in both Canada and the U.S., should not be considered:

> … reference to either sets of decisions – Canadian and U.S. – as benchmarks of what is a fair return is unnecessary since the better approach is to examine the evidence of required returns estimated by experts using techniques founded on sound principles of finance.[245]

241 Exhibit 179.02, Evidence of Drs. Kryzanowski and Roberts, page 324.
242 Decision 2004-052, page 23.
243 AltaLink, EPCOR utilities, FortisAlberta and ATCO utilities.
244 Written Evidence of Mr. Coyne, Exhibit 50.01, Section 3.0, page 41.
245 Written Argument of CAPP, Exhibit 388.02, paragraph 403.

284. The Commission agrees with CAPP that the better approach is to examine the direct evidence of the experts in this proceeding, particularly because the awards of other regulators were established on the basis of a different record.

285. In Section 3.2.3 of this Decision, the Commission determined that it would not consider return awards by U.S. regulators, although it expected market determined returns for U.S. utilities may be examined on a market risk-adjusted basis in assessing a fair return for stand-alone Alberta utilities.

286. The Utilities generally recommended that the Commission give careful consideration to the NEB's recent TQM Decision, which set an allowed return for 2007 and 2008. As noted in Section 3.3 of this Decision, the Commission has distinguished the TQM Decision and indicated it would not consider that decision in determining a fair return for Alberta utilities.

287. The Commission observes that the determination to place no weight on Canadian allowed returns was also made by the NEB in the TQM Decision.

> On the question of whether litigated Canadian utility returns are similar because of problems of circularity, or whether they provide a valid signal because they represent independent conclusions reached on similar questions, the Board finds that there was no evidence that conclusively supported either view. Faced with contrasting opinions on the matter, and with the option of relying on returns from other submitted comparables, the Board placed no weight on Canadian litigated returns.[246]

### 5.6 Price-to-Book Ratios

288. An equity price-to-book ratio is calculated by dividing the current market price of a stock by its current book value per share. It is often used to compare a stock's market value to its book value. There was considerable debate during the proceeding as to the relevance, if any, of price-to-book ratios.

289. Calgary stated "as Dr. Booth noted … a price to book ratio does not indicate that precise level of the required fair return; rather it is indicative of the general level of the return. If the price to book ratio is below 1 then generally one would consider that the return is too low, while if it is above 1.2 it would generally indicate an adequacy to somewhat above that required or the fair return."[247] Dr. Booth also noted that the price-to-book data in the proceeding generally did not relate to stand-alone utilities and was therefore of little value.[248] Dr. Booth provided his calculations of the implied price-to-book ratios for a number of recent corporate purchases of utilities, which ranged from 1.31 to 1.80.[249]

290. Mr. Engen quoted from the text on *Public Utility Regulation* by Dr. James C Bonbright as follows:

> It follows that the common stocks of public companies which actually succeed in earning a fair rate of return as derived by a cost of capital technique can be expected to command

246 TQM Decision, page 69.
247 Calgary Argument, Exhibit 386.02, page 18.
248 Transcript, pages 3544-3547.
249 Dr. Booth Revised Evidence, Exhibit 292.03, pages 119-120.

substantial premiums over their book values or rate base values except in periods of a seriously depressed stock market.[250]

291. Mr. Engen provided a table which summarized his estimate of recent price-to-book values for a number of Canadian utility holding companies, which ranged from 0.6 to 1.7.[251]

292. Dr. Vander Weide questioned the relevance of the price-to-book ratios and submitted that:

> According to the DCF model, a company's stock price is equal to the present value of the company's expected future dividends, which, in turn, depend on its expected future ROEs. Thus, market-to-book ratios greater than 1.0, at best, imply that investors expect the company to earn more than its cost of equity at some time in the future. There is nothing in the DCF model that allows the analyst to draw inferences about the relationship between a company's historical ROE and its cost of equity from evidence on market-to-book ratios."[252]

293. Mr. Edmondson, appearing for ATCO, stated that when a company is valuing investment opportunities, price-to-book ratios would be one of the last tools it would employ.[253] With respect to corporate disposition and acquisition values, ATCO submitted that "while corporate acquisition transactions provide an indication of price-to-book ratios that investors have been willing to pay for utility assets, that information does not tell us whether investors consider the current return on regulated assets fair".[254]

294. Mr. Coyne submitted that a price paid to acquire a utility above book value may reflect some premium based on the acquiring company's belief that the acquisition will result in improved cost efficiency, or that the acquisition will provide them with an opportunity to serve an expanding territory or customer base, or that the acquisition provides a good strategic fit with other businesses in their corporate portfolio.[255] Both Mr. Coyne and Dr. Vander Weide indicated that in periods of inflation historical costs would be less than the current market cost and could account for price-to-book differences.[256]

295. The Commission considers that a price-to-book ratio of approximately 1.2 for a stand-alone utility would generally indicate that the return is at least fair. However, the Commission is unable to derive any useful information about the price-to-book ratios of stand-alone utilities from the price-to-book ratios for utility holding companies.

296. AltaGas indicated that AltaGas Utilities Group Inc. trades significantly below its book value,[257] which discourages new investment as any dollar invested is worth less than a dollar to market investors[258] and is dilutive to existing shareholders.[259] However, the Commission notes

250 Exhibit 52.02, Evidence of Aaron M. Engen, page 111 of 120.
251 Exhibit 279.01, Rebuttal Evidence of Aaron Engen, pages 21-22.
252 Exhibit 282.01, Vander Weide Rebuttal Evidence, page 10.
253 Transcript, pages 1328-1329.
254 Exhibit 128.02, AUC-ATCO UTL-6(b).
255 Exhibit 128.02, AUC-ATCO UTL-15(d).
256 Exhibit 128.02, AUC-ATCO UTL-15(b)b; Exhibit 282.01, Vander Weide Rebuttal Evidence, Exhibit 282.01, page 75.
257 Exhibit 58.02, Tab 2, Vilbert Evidence, pages 16-17 and 22.
258 Ibid.

that AltaGas Utilities Group Inc.'s financial statements dated December 31, 2007[260] indicate that AltaGas Utilities Group Inc. had substantial goodwill on its balance sheet. Because AltaGas is regulated on the basis of a return on rate base, which excludes goodwill, the price-to-book value of AltaGas Utilities Group Inc. is not of assistance.

297. The (equity) price-to-book ratio for the 2007 Fortis acquisition of Teresen Inc. was discussed on the record of the proceeding as a potential indicator of the price-to-book ratio for a stand-alone utility. However, there was considerable disagreement as to the correct calculation of the price-to-book value for this transaction. Price-to-book values in the range of 1.27[261] to 3.99[262] were provided. Despite the lack of agreement with respect to the exact calculation, the evidence is that the price paid for Teresen Inc. was at a price-to-book ratio above 1.2. It appears therefore that the awarded return for Teresen was at least fair, at the time of the transaction. However, there is ample evidence on the record that conditions in the market have changed significantly since the Teresen transaction in 2007, and the Commission cannot rely on this transaction as indicative of a fair return for 2009.

## 5.7 Returns Available on High Grade Corporate Bonds

298. Returns available on Canadian corporate bonds with investment grade ratings of BBB or higher were continuously changing over the course of this proceeding. The spread between the yield on high grade corporate bonds over the risk free rate spiked upward during the last quarter of 2008 and the first quarter of 2009. Mr. Engen for the ATCO Utilities referred to the historical A- corporate bond spread and the effects of the financial crisis on that historical spread as at the end of March 2009 as follows:

> The current credit spread for Canadian A-rated corporate bonds is 308 basis points (for the two quarters ending March 2009), whereas historically that average spread was approximately 125 basis points.[263]

299. CAPP acknowledged that high grade Canadian corporate bond spreads had indeed widened during the financial crises but observed that spreads were trending downwards as at the close of the oral hearing:

> Corporate bond spreads have come down significantly since the dark days when CAPP's evidence was prepared. Generic corporate bond spreads had come down to about 200 basis points in early June with utility bond spreads at 170, 175 basis points. CU Inc.'s spreads as of early June were down to 168 basis points. … The effect of the financial crisis is temporary and the evidence of the ability to attract capital during the crisis demonstrates that regulatory support is sufficient.[264]

259 Exhibits 157.01, AUC-AUI-10(a) and 163.01, UCA-AUI-12(a). The UCA argued that the ratio is only below one if goodwill and other intangibles are included in its book value. UCA Reply Argument, page 12

260 Exhibit 58.02, AltaGas Evidence, Section 1.9.4, page 1.

261 Transcript, page 1319, line 17.

262 Exhibit 117.03, UCA-EPC, page 120, lines 10-11.

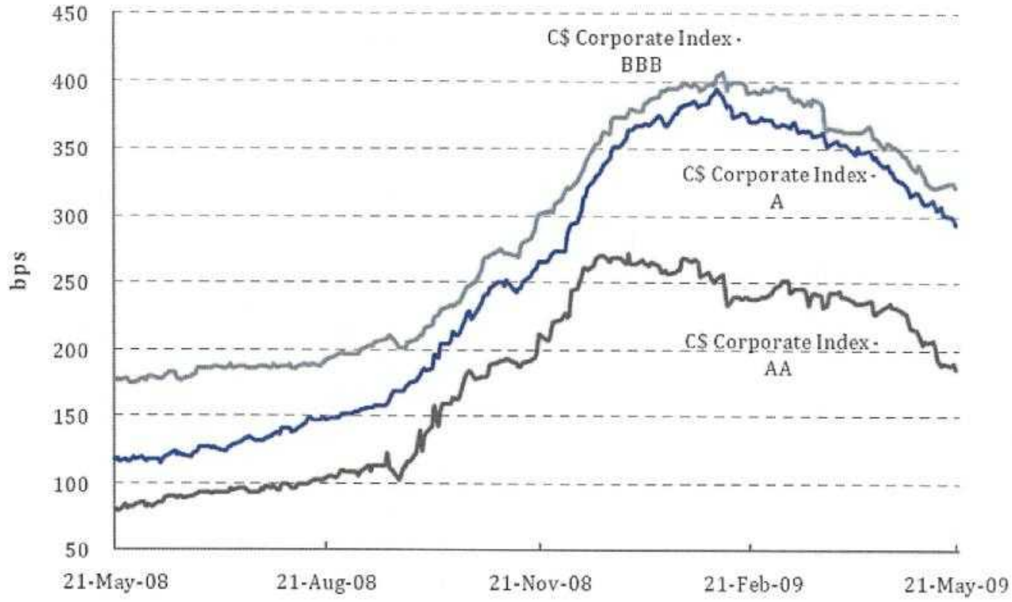
263 Coyne Rebuttal Evidence, Exhibit 279.01, page 3.

264 CAPP Written Argument, Exhibit 388.02, pages 6-7.

300. Figure 1 below was provided in an undertaking response by Dr. Roberts. It demonstrated that the high grade corporate bond credit spreads have recovered significantly since the peak of the financial crisis:[265]

**Figure 1 Canadian Bond Spreads**

Exhibit 2: C$ bond indices continue their march to tighter levels



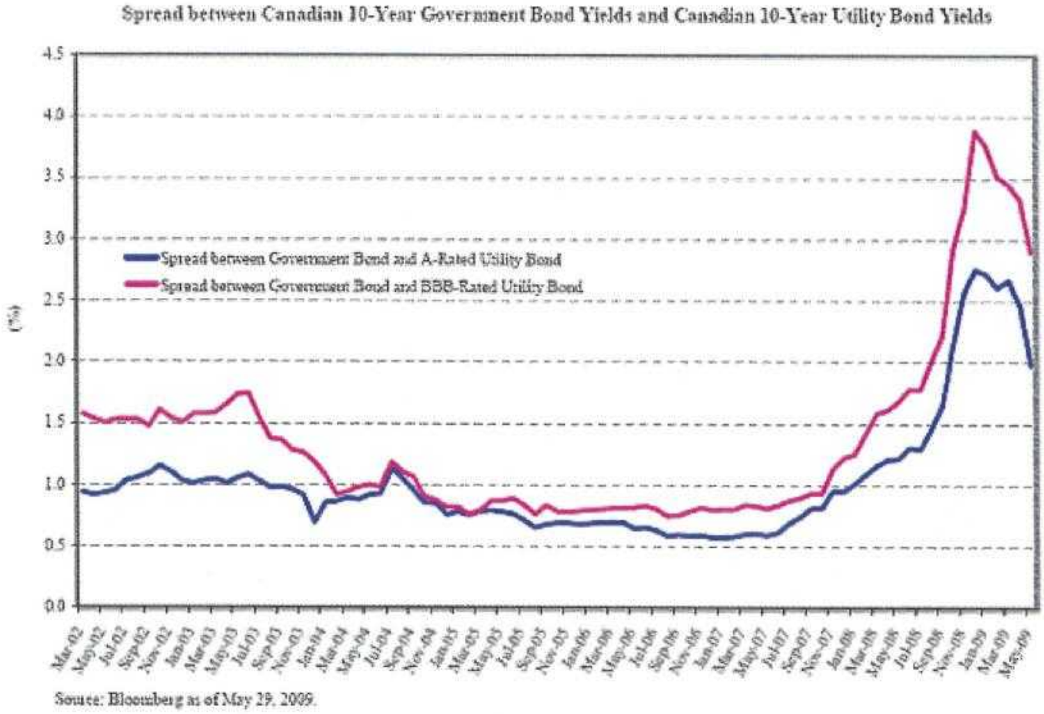

Source: Bloomberg

301. Canadian utility bonds are a subset of Canadian high grade corporate bonds. As demonstrated in Figure 2 below the experience of Canadian utility bonds has been similar to Canadian corporate bonds in general with spreads to long Canada bonds widening in the spring of 2008 and starting to decline in the later half of 2008. Figure 2 below was provided by Dr. Vilbert in an undertaking response by Dr. Vilbert to counsel for the UCA:[266]

265 Undertaking given at Transcript, page 3018, line 1 to provide most recent RBC Capital Markets Credit Weekly Report. Chart appears in Exhibit 368.04, the RBC Credit Weekly Report Volume 20 (May 22, 2009) at page 3.

266 Undertaking given at Transcript Volume 14, page 13, Chart appears in Exhibit 359.01.

**Figure 2 Canadian Utility Bond Spreads**




Source: Bloomberg as of May 29, 2009.

**Figure 2**

302. Mr. Engen, on behalf of the ATCO Utilities, responded to a questions about recent decline in corporate bond spreads as follows:

> There's no question that spreads have tightened in, and for some issuers, materially, since the beginning of the year. Whether they go back to more normal spreads, difficult to say. Partly because I'm not sure what we mean when we say "normal spreads." There's no expectation, and that doesn't mean it won't happen, but there is no expectation amongst the various debt capital market groups, the investment banks, that we're going to go back to the spreads we saw last spring, last summer, where they were very, very tight. There was abundant capital. At the time, it appeared that investors either mispriced risk, didn't care about risk, or misunderstood the risks they were assuming.
>
> Our expectation is that we are seeing a repricing of risk. There may be some more tightening in, but we don't expect to see it going back to the ten-year average spreads that we saw, which for 30-year bonds stood around 100 basis points for A minus rated entities last spring, early summer.[267]

303. The utilities asserted that a re-pricing of risk on high grade Canadian corporate bonds as demonstrated by the increased spreads must mean that there has been at least a similar increase in the cost of equity capital given that future return expectations of equity investors must always be higher than the lower risk expectations of debt investors. Dr. Booth appearing on behalf of CAPP appeared to accept the premise in the following exchange with Commission Counsel:

[267] Transcript, page 1048, line 13 to page 1049, line 8.

> Q. So, sir, if I understand your position correctly, the utility equity issuer must be competing for the expected return on utility bonds, and that's what they are competing against, not the yield on bonds?
> A. DR. BOOTH: That's absolutely correct.[268]

304. Dr. Booth asserted however that it was not possible to draw direct linkages between increased credit spreads in the Canadian bond market and increase return expectations by equity investors. In his opening statement at the oral hearing Dr. Booth stated:

> However, as I say in my testimony, it is a fundamental error to assume that you can simply compare promised yields on default risky bonds with expected returns on stocks as if they are the same; they are not. Default spreads on A bonds are driven by different factors to those that drive equity risk premia.[269]

305. Dr. Booth stated in his evidence that trading liquidity less than that of Government of Canada bonds cause Canadian corporate bond spreads to suffer from a liquidity premium. Corporate bond spreads are wider partially because there is less trading liquidity in corporate bonds which is exacerbated by the many various tranches of corporate debt resulting in further liquidity premiums.[270] He further stated:

> It is quite obvious that unlike the fixed income market where there have been and always are serious liquidity problems during a recession and consequent flight to quality, no such liquidity problems are apparent in the equity market. Rewarding equity holders with a higher ROE as a result of liquidity problems in the bond market does not have any economic justification.[271]

306. Mr. Engen disagreed with Dr. Booth's contention that higher bond spreads in Canada were a result of a liquidity problem brought on by the financial crisis and that it was improper to make assumptions about increased equity investor expectations from increased expectations of bond holders. In his Rebuttal Evidence Mr. Engen stated:

> ...arguments suggesting that trading illiquidity is the driver behind the higher yield spreads for the Canadian generic A-rated corporate and utility spreads point to a fundamental misunderstanding of the bond market and how bonds are priced.[272]

307. Mr. Engen explained that corporate bonds do not need to be as frequently traded as Government of Canada bonds to avoid a liquidity premium. As an investment banker, Mr. Engen stressed that the Commission should have regard to actual capital market expectations by stating:

> ...BMO Capital Markets is of the view that the proportion of corporate trading volumes relative to outstanding corporate bonds (or bid/offer indications) are sufficiently high that liquidity premiums are not required by the market for the corporate and utility bonds used to develop its Canadian generic A-rated corporate and utility bond spreads.[273]

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268 Transcript, page 3357 lines 3-7.
269 Transcript, page 3148 lines 8-14.
270 Revised Evidence of Dr. Booth, Exhibit 292.03, pages 88-95.
271 Revised Evidence of Dr. Booth, Exhibit 292.03, page 95.
272 Engen Rebuttal Evidence, Exhibit 279.01, page 19.
273 Engen Rebuttal Evidence, Exhibit 279.01, page 20.

308. As has occurred throughout this Proceeding, the Commission must weigh conflicting expert testimony on various factors impacting the determination of a fair return for Alberta utilities. The Commission considers the increased high grade Canadian corporate bond spreads which occurred during the financial crisis and which continued to occur, albeit on a downward trend, at the close of the Proceeding demonstrate that there has indeed been some re-pricing of risk on debt securities. Equity investors in high grade rated companies have more default risk than do debt investors. An increase in debt investor return expectations ordinarily must be considered to result in an increase in return expectations for equity investors otherwise equity investors would not accept the incremental risk associated with equity ownership. The Commission finds that there is insufficient evidence on the record of the proceeding that illiquidity in the Canadian bond market during the financial crisis can account for a significant portion of the increased risk premium demanded by bond investors.

309. While high grade Canadian corporate bond spreads have declined materially since the peak of the financial crisis, the evidence available at the close of the proceeding indicated that some degree of increased corporate bond spread continued compared with pre-financial crisis levels. As described by Mr. Engen above, the high grade Canadian corporate bond spread prior to 2007 averaged 125 basis points[274]. At the close of the oral hearing, CAPP stated "Generic corporate bond spreads had come down to about 200 basis points in early June with utility bond spreads at 170, 175 basis points."[275] It appears that corporate bond spreads remained at the close of the Proceeding approximately 50 basis points higher than pre-financial crisis levels.

310. The Commission notes the observation of Dr. Booth in the following exchange with counsel for the ATCO Utilities that 50 basis points is the approximate level of "excess spread" required in the debt market for high grade Canadian utility bonds at the time of the oral hearing.

> Right now the yields on utility debt in Canada are down to 170, 175 basis points. The yields on CU debts (sic) below that, about 168 basis points. That was as of last week and they've been dropping 10, 20 basis points in the last week or so. So what's happening is utility spreads are tightening dramatically. What I would expect, given that where we are in the economy, I would expect those utility spreads to be more like 125 basis points. So I would guess there's still about a 50 basis point, what I would regard as excess spread. And most of the people writing newsletters are saying there's still value to be had in buying corporate bonds.[276]

311. It remains an open question whether corporate bond spreads will quickly, if ever, return to pre-financial crisis levels. In particular, it remains uncertain that the re-pricing of risk observed in high grade Canadian corporate bond spreads in the period up to the close of the Proceeding will end in either 2009 or 2010. In these circumstances, it is reasonable to conclude that the actual return expectations of utility equity investors in 2009 and 2010 would be at least 50 basis points higher than estimates of equity return expectations derived from methodologies like CAPM which rely solely upon historical data and the risk free rate.

274 Coyne Rebuttal Evidence, Exhibit 279.01, page 3.
275 CAPP Written Argument, Exhibit 388.02, pages 6-7.
276 Transcript, pages 3218-3219.

## 5.8 Pension, Investment Manager and Economist Return Expectations

312. In Decision 2004-052, the Board considered evidence on the expectations of pension and investment managers. There was relatively little evidence of, or discussion on, the expectations of pension and investment managers in this proceeding.

313. The UCA argued that the Commission should accept survey results from pension and investment managers and other knowledgeable sources as valid benchmarks against which ROE or MERP recommendations can be assessed.[277] Specifically, the UCA referred to the evidence of Drs. Kryzanowski and Roberts, who used the return expectations from surveys of professional economists and portfolio managers provided by Watson Wyatt. The UCA stated that the most recent forecasts collected by Watson Wyatt reported median total return expectations of 7.5 percent for the S&P/TSX Composite Index for both the mid-term (2010-2013) and long-term (2014-2023).[278] They concluded that the ROE recommendation of 7.9 percent for 2009 from Drs. Kryzanowski and Roberts is conservatively high.[279]

314. Mr. Engen indicated that, from his discussions with the major Canadian pension funds, he understood that pension funds expect energy infrastructure investment returns on capital in the order of a minimum of 7.5 percent to 8.5 percent with returns on equity in the range of 10.0 percent to 12.0 percent.[280] ATCO argued that this evidence demonstrates that potential investors in infrastructure are looking for returns that are significantly higher than recommended by Drs. Kryzanowski and Roberts. However, the Commission finds that the evidence of Mr. Engen, on pension fund expectations, is anecdotal and cannot be relied upon.

315. With respect to the Watson Wyatt evidence relied upon by Drs. Kryzanowski and Roberts, the Commission takes this as one indication that professional economists and portfolio managers expect that returns for the market as a whole may decline, over the medium to long run, once the effects of the financial crisis have dissipated. At issue for the Commission, however, is the speed at which the effects of the financial crisis will indeed abate.

## 5.9 Negotiated Settlements

316. There was no suggestion by any party to the proceeding that the Commission should take any guidance from the results of recently negotiated general rate application settlements when establishing a fair return for the utilities. The UCA recommended that the Commission not place any weight on negotiated settlement evidence presented in this proceeding, and that all negotiated settlements cannot be used to set any precedents because they are made up of a series of compromises.[281]

317. CAPP argued that the Commission should not have regard to negotiated settlements because:

> … settlements involve tradeoffs. Using negotiated agreements as precedents would take agreements negotiated as package deals and that are only acceptable to the parties as a complete package and cherry pick one item, the return opportunity, as the precedent. It would completely chill the freedom to negotiate within established regulatory

[277] UCA Argument, Exhibit 387.01, page 38.
[278] Ibid.
[279] UCA Argument, Exhibit 387.01, page 38.
[280] Exhibit 52.02, Engen Evidence, page 85.
[281] UCA Argument, Exhibit 387.01, page 90.

> frameworks if those same agreements were used as precedents to ratchet or re-jig the regulatory framework itself. That would turn without prejudice agreements into with prejudice agreements. Finally, the confidential nature of such negotiations prevents any ability to look through the agreements and see all the tradeoffs being made.[282]

318. ATCO, in response to a question from Mr. McNulty with respect to the relevance of the recently negotiated ATCO Pipelines settlement, appeared to agree with the interveners on this matter.

> The suggestion that the settlement could be taken as evidence that ATCO Pipelines considered a lower ROE to be a fair return is, with respect, improper and lacks balance, unfairly prejudicing the utility. The language in the settlement is perfectly clear that the return and capital structure, which were deemed values for purposes of the settlement, could not be taken as precedential or prejudicial to positions taken, specifically, in this generic cost of capital proceeding.[283]

319. The Commission agrees with parties that negotiated general rate applications settlements cannot be considered in setting the allowed ROE for a utility, because they are made up of a series of compromises and are not of assistance in determining the expected market return for a stand-alone utility.

### 5.10 Expected Canadian Average Stock Market Returns

320. Dr. Booth's forward looking ROE for the Canadian equity market was developed by assuming that the average dividends since 1961 for the TSX, at 2.4 percent of GDP, and after tax corporate profits of 6.4 percent, imply an average real Canadian growth rate since 1961 of approximately 3.53 percent. Dr. Booth assumed that the "Bank of Canada's inflation rate forecast of 2.0%, implying a long-run growth rate in dividends and earnings of about 5.60%."[284] He then added the assumed long run growth rate to the current dividend yield on the TSX of 4.04 percent to derive a DCF estimate of approximately 10.0 percent. However, Dr. Booth argued that this result over-estimates the required rate of return because "short run growth prospects are considerably poorer than the long run rate."[285] To counteract this he applied a two-stage growth model where the current dividend is expected to be constant for the first two years then recover in 2010, at which time the growth rate is assumed to be the long run growth rate of 5.60 percent. As a result, Dr. Booth estimates a return on the S&P/TSX of 9.25 percent.

321. Dr. Vander Weide disagreed with Dr. Booth's application of the DCF method to the Canadian market as a whole stating the assumptions of the DCF model do not apply to the Canadian market as a whole. He reasoned that the DCF model is based on the fundamental assumption that a company's stock price is equal to the present value of the cash flows investors expect to receive from investing in the company's stock, that it is very difficult, if not impossible, to match stock prices and cash flows for the Canadian market as a whole, and that the DCF model cannot be applied to companies in the Canadian market that do not pay dividends. The TSX includes companies that do not pay dividends and the TSX companies may

282 CAPP Argument, Exhibit 388.02, page 35.
283 ATCO Argument, Exhibit 390.02, page 105.
284 1.02*1.0353.
285 Dr. Booth Revised Evidence, Exhibit 292.03, page 101.

grow for many years at a growth rate that is significantly different from that of the Canadian economy.[286]

322. The Commission rejects Dr. Vander Weide's concerns that Dr. Booth's application of the DCF method to the Canadian stock market as a whole is fundamentally flawed. The Commission finds Dr. Booth's forecast to be reasonable, and will take it into consideration in its determination of the utilities' required ROE because all that is required to calculate returns using the DCF model is an initial dividend yield and justifiable short- and long-term forecast dividend growth rate.

### 5.11 The Commission's Awarded ROE

323. The Commission is required to establish a fair rate of return on equity for 2009 and going forward for the utility companies it regulates. In keeping with the Commission's determinations above, the Commission will establish a generic ROE to be applied to each of the utility businesses it regulates as if they were stand-alone utilities. The Commission has reviewed the models and approaches adopted by the various parties and, based on the analysis above, has found that some of the CAPM and DCF results filed in this proceeding (including an analysis of the expected overall Canadian stock market returns) will form the primary basis for its ROE determinations. All of the Commission's analysis has been conducted in the context of, and having regard to, the uncertainties created by the current financial crisis that began in the third quarter of 2007.

324. The generic ROE established by the Board in 2004 and the annual adjustment formula adopted at that time were developed based on the assumption that certain key relationships in the financial markets would continue. In particular, the Board relied on CAPM as the primary basis for the 2004 awarded ROE and annual adjustment formula. As explained in Section 7 of this Decision the Commission accepts that, during the current financial crisis, the traditional relationship between the risk free rate (measured as the yield on long Canada bonds) and the required market return on equities has not continued. Therefore, the Commission has found it necessary to make certain adjustments to its CAPM analysis and also considered some of the DCF analysis, as well as other factors in arriving at a fair ROE.

325. Based on the Commission's findings with respect to CAPM, the Commission found a reasonable range of CAPM results of 7.13 percent to 8.62 percent. However, given the Commission's observations with respect to the impacts of the financial crisis on the traditional relationships in the financial market, the Commission considers that these CAPM may be unreasonably low.

326. The Commission's analysis of the performance of high grade bonds relative to the risk free rate during the financial crisis, as explained in Section 5.7, reveals that the traditional spread between the long Canada bond yield and the yield on high grade bonds had increased to well above the traditional spread of one percent and by the close of the record in the proceeding had moved back to a spread of approximately 1.5 percent. As a result, the Commission concludes that the CAPM results likely underestimate the required market equity return by at least 50 basis points. Accordingly, the Commission has adjusted its CAPM results to arrive at a range of 7.63 percent to 9.12 percent.

286 Exhibit 282.01, Dr. Vander Weide Rebuttal Evidence, pages 55-56.

327. The Commission has also considered some of the DCF results on the record of this proceeding to be relevant to its consideration of a fair rate of return. In doing so, the Commission is mindful of some of the shortcomings of DCF expressed by parties. Specifically, the Commission is concerned that it is necessary to perform the analysis on proxy companies that may have significant unregulated assets. In addition the Commission recognizes that the DCF analysis depends on potentially optimistic forecasts of financial analysts. Nevertheless, the Commission does have DCF results for two Canadian utility holding companies with close to one hundred percent of their assets in regulated businesses. Dr. Vilbert's multi-stage DCF analysis for these two companies (Emera Inc. and Fortis Inc., which were part of his Canadian proxy group) yielded results of 8.80 percent and 9.20 percent respectively.[287] The Commission also examined the results of multi-stage DCF studies provided by Dr. Vilbert for his Canadian proxy group and two U.S. proxy groups. These results gave the Commission comfort that the DCF results for Emera Inc. and Fortis Inc. are reasonable. The Commission finds the DCF results for these two companies instructive because the companies closely resemble stand-alone regulated utilities. Overall the Commission found that the DCF results suggest a range of ROEs for Canadian stand-alone utilities of 8.8 percent to 9.3 percent, assuming that the equity ratio has been set to target a credit rating in the A range.

328. The Commission also considered the evidence of Dr. Vander Weide on the historical returns for the TSX from 1956 to 2008 which determined that the average stock market return over that period was 10.30 percent. This result largely mirrored the analysis of Dr. Booth that estimated the historical return on the TSX at 10.14 percent.[288] The Commission also considered Dr. Booth's forward-looking DCF analysis of the expected average stock market return for the S&P/TSX, which showed a result of 10 percent, which Dr. Booth adjusted downward to 9.25 percent on the assumption that the returns for the first two years of his study period would be depressed.[289] The Commission recognizes that stand-alone utility companies, because of their relatively low risk, would be expected to earn returns over the long run that are lower than the expected return for the overall Canadian stock market. This conclusion is supported by the fact that every expert witness in the Proceeding recommended a beta of less than one. In addition, the Commission notes that Mr. Engen, appearing for the ATCO Utilities, when discussing the requests of the utilities in this proceeding stated that "... I don't think anybody is looking to achieve the same kinds of returns long term or otherwise that you would expect in the marketplace generally."[290] Accordingly, the Commission considers that it would be unreasonable to award stand-alone utilities an ROE in excess of 9.775, being the midpoint of the range of 9.25 percent to 10.30 percent.

329. The Commission recognizes that monopoly utility companies are generally considered by many to be relatively low risk investments. The Commission heard evidence during the Proceeding that the non-utility company share values fluctuated significantly during the financial crisis while the shares for utility holding companies remained fairly stable.[291] In the Commission's view, this demonstrates that the utility holding companies are perceived by investors to have less risk than non-utility holding companies. This conclusion is borne out by the fact that the unadjusted beta for utility holding companies during the peak of the financial

287 These numbers include a floatation allowance of .50 added by the Commission.
288 Dr. Booth Revised Evidence, Exhibit 292.03, page 85.
289 Dr. Booth Revised Evidence, Exhibit 292.03, page 101.
290 Transcript, page 1511.
291 Dr. Booth Revised Evidence, Exhibit 292.03, page 80 and Mr. Engen, Exhibit 310.

crisis dropped to very low levels.[292] It follows that stand-alone utilities would have less risk than the utility holding companies and therefore must have even lower betas.

330. The Commission is mindful that evidence on professional economists' and portfolio managers' expectations suggests that returns for the market as a whole may decline over the medium to long run once the effects of the financial crisis have dissipated. The Commission also recognizes that there remains a considerable amount of uncertainty in the financial markets and the Commission is concerned that awarding a generic ROE that does not take these uncertainties into account would be unreasonable.

331. Having considered and weighed all of the evidence and assessed it in the context of the current financial crisis, it is the Commission's judgment that the generic ROE for 2009 should be set at 9.0 percent.

# 6 CAPITAL STRUCTURE

## 6.1 Introduction

332. To satisfy the fair return standard, the Commission is required to determine a capital structure (equity ratio) for each of the utilities that are the subject of this Proceeding. In this Decision, the Commission has established a generic ROE of 9.0 percent which will be applied uniformly to all of the utilities. As the Board did previously, the Commission will account for the differences in risk among the individual utilities by adjusting their capital structures.

333. In general, the return required by investors on debt is lower than the return required on equity. This is because debt holders have priority over equity holders in the distribution of earnings from operations and, in the event of bankruptcy, in the disposition of the assets of the firm. As the proportion of debt in the capital increases, a greater portion of the earnings from operations of the firm are required to cover the increased interest costs on debt. As the proportion of debt rises, both debt and equity investors will perceive an increase in risk. Debt holders will be concerned that the debt obligations of the firm may not be met, and equity investors will be concerned that there will be insufficient earnings from operations to both cover the debt obligations of the firm and pay them their expected return. This risk is usually assessed by various interest coverage calculations that measure the ability of the firm to pay its debt obligations. Bond rating agencies, such as Dominion Bond Rating Services (DBRS) assess the risk of individual firms on the basis of various interest coverage metrics and an overall assessment of the risk that the firm will not be able to both cover its debt obligations and pay a return to its shareholders.

334. In this Decision, the Commission will establish, for each utility, the capital structure that, in the Commission's judgment, would allow a stand-alone utility to maintain a credit rating in the A range subject to company-specific circumstances. To do so, the Commission will first consider the record of the Proceeding on the overall risk of regulated utilities posed by the current credit environment and current utility credit metrics. The Commission will then assess, on the basis of the record of the Proceeding, the risk of each of the utility sectors and determine a relative ranking of risk for each sector and the commensurate equity ratio that, in the Commission's judgment, will allow the utilities in each sector to maintain the desired credit

292 Dr. Booth Revised Evidence, Exhibit 292.03, page 73.

rating. Finally, the Commission will turn to an assessment of each individual utility to determine whether specific adjustments to each company's equity ratio are warranted.

335. The following table (grouped by sector) compares the equity ratios that were approved by the Board in Decision 2004-052 (and in the case of EEAI, in its most recent GTA) with the equity ratios recommended by the applicants and interveners in this Proceeding.

**Table 11. Recommended Equity Ratios vs. Last Board Approved Equity Ratios**

| | Last Approved (%) | Recommended by Utility[293] (%) | Recommended by UCA & CCA[294] (K&R) (%) | Recommended by Calgary[295] (Booth) (%) | Recommended by CAPP[296] (Booth) (%) |
|---|---|---|---|---|---|
| **Electric and Gas Transmission** | | | | | |
| ATCO Electric TFO | 33.0 | 38.0 | 33.0 | <35.0 | |
| AltaLink | 33.0 | 38.0 | 33.0 | <35.0 | |
| ENMAX TFO | 35.0 | 40.0 | 30.0 | | |
| EPCOR TFO | 35.0 | 40.0 | 30.0 | | |
| ATCO Pipelines | 43.0 | 43.0 | 42/34[297] | | 37/33[298] |
| **Electric and Gas Distribution** | | | | | |
| ATCO Electric DISCO | 37.0 | 40.0 | 35.0 | | |
| ENMAX DISCO | 39.0 | 44.0 | 35.0 | | |
| EPCOR DISCO | 39.0 | 44.0 | 35.0 | | |
| ATCO Gas | 38.0 | 40.0 | 34.0 | 35.0 | |
| ATCO Gas for 2008 | 38.0 | 40.0 | 38.0[299] | | |
| FortisAlberta | 37.0 | 42.0(+ 2)[300] | 35.0 | | |
| AltaGas | 41.0 | 46.0 | 40/37[301] | 40.0 | |
| **Retailers** | | | | | |
| EEAI | 37[302] | 42.0 | 35.0 | | |

336. The CCA did not sponsor evidence but, in argument, supported the equity ratios submitted by Drs. Kryzanowski and Roberts. Calgary indicated in argument that it generally supported the positions taken by the UCA. CAPP submitted in argument that it had limited its capital structure recommendation to ATCO Pipelines.

## 6.2 Credit Environment

337. During the hearing, evidence was introduced by the utilities and generally accepted by the interveners regarding the financial crisis that affected the world beginning late in 2007. The parties, however, disagreed over whether the crisis had ended or whether there were some lingering and potentially long-term effects.

293 ATCO Evidence, Exhibit 50.01, page 5, Dr. Vander Weide Joint Evidence, Exhibit 57.04, page 37, Dr. Vilbert, Exhibit 58.02, page 24, ENMAX Evidence, Exhibit 55.01, page 6.
294 Evidence of Drs. Kryzanowski and Roberts, Exhibit 179.02, page 6.
295 Calgary Argument, Exhibit 386.02, pages 12-13.
296 CAPP Argument, Exhibit 388.02, page 94.
297 42.0 percent without NGTL Integration Agreement, 34.0 percent with NGTL Integration Agreement.
298 37.0 percent without NGTL Integration Agreement, 33.0 percent with NGTL Integration Agreement.
299 UCA Argument, Exhibit 387.01, page 97.
300 42.0 percent Recommended by Dr. Vander Weide, 44.0 percent Requested by FortisAlberta for non-taxable status.
301 40.0 percent without weather deferral account, 37.0 percent without weather deferral account.
302 Exhibit 53.04, Evidence of Dr. Vander Weide, page 37.

338. Interveners argued that "since the dark days when interveners filed their evidence, there have been significant improvements in capital markets."[303] They pointed to a number of improving financial and economic indicators that supported their claims. Hence, the Commission, the interveners urged, "should not be concerned with the allegations that any problems raising capital are not short term."[304]

339. The utilities argued that what the world experienced in terms of economic and financial meltdown was something of an unprecedented nature that fundamentally altered the perception of risk and that it will have long-term consequences. ATCO, for example, argued that "[e]quity risk has been re-priced pure and simple."[305] Furthermore, citing Mr. Coyne's rebuttal evidence, ATCO argued that "the faith of investors has been severely shaken by the sudden downturn in equity valuations and dislocations in the financial system, and such shifts in investor sentiment may take years or decades to return to 'normal'."[306]

340. AltaGas also argued that even though "the worst of the crisis is perhaps behind us," risk-averse investors have not restored their confidence in the market to where they were before the crisis.[307] Similarly, AltaLink's Mr. Bronneberg testified at the hearing that the capital markets "are still under tremendous pressure and remain volatile and unpredictable."[308] In a cautionary fashion, he warned that given the nature of the financial crisis, "another unexpected event could trigger a material reversal in this recovery."[309]

341. In light of this and other exchanges during the hearing, the Commission accepts that the financial markets have not returned to typical pre-2007 behavior, and the long term effects of the crisis, ranging from the continued elevated corporate bond spreads, short-term interest rates close to zero, the rapidly increasing size of government deficits, and the continuing job losses in the U.S., are still present.[310]

342. The Commission must also consider that the events that drove the original crisis will be factored into investors' perceptions. Companies will therefore protect their balance sheets and investors will adjust risk perceptions whether unexpected events present themselves again or not. In order to protect investors' and ratepayers' interests, the Commission must award equity ratios that recognize the need for the ongoing viability of the utility even in adverse conditions. Therefore, the Commission will increase allowed equity ratios.

### 6.3 Credit Metrics and Actual Credit Ratings

343. Credit-ratings measure the credit-worthiness of a firm. A higher credit rating signals higher confidence in the firm's ability to meet its interest payments. This, in turn, allows the company to borrow at a lower interest rate. Utilities usually seek to maintain a credit rating in the A range.

303 CAPP Argument, Exhibit 388.02, paragraph 274.
304 UCA Argument, Exhibit 387.01, page 83, paragraph 379.
305 ATCO Argument, Exhibit 390.02, page 48, line 14.
306 ATCO Argument, Exhibit 390.02, page 48, lines 20-23.
307 AltaGas Reply Argument at page 8.
308 Transcript at page 201, lines 2-4.
309 Transcript at page 201, lines 5-6.
310 See paragraph 46 above.

344. A number of Canadian utility companies finance their debt requirements directly in the debt market independently of any affiliated companies, thereby ameliorating the "dirty window" challenges. Therefore, the Commission will examine the credit ratings of such companies, for which credit rating reports were available on the record, in order to gain some insight into the credit metrics required to achieve an investment grade credit rating for a stand-alone Canadian utility.

345. There are three principal credit metrics. They are:

- EBIT Coverage (interest coverage ratio), which is the company's earnings measured before deducting interest and taxes divided by total interest costs;
- FFO/Debt, which is the company's funds from operations as a percentage of total debt;
- FFO Coverage, which is the company's funds from operations divided by total interest costs.

346. The utilities argued that it was necessary for their companies to meet or exceed minimum standards for these metrics in order to maintain a credit rating in the A range. The utilities pointed to some minimum credit metrics published by the bond rating agencies as providing guidance to the Commission.[311] The Commission observes that these "minimum credit metrics" are more in the nature of general guidelines and that they are no longer consistently published by credit rating agencies.[312]

347. The following table provides the actual credit ratings and corresponding key financial ratios (or credit metrics) for the Canadian utility companies that raise debt independently and for which credit reports were available on the record. The Commission did not include government-owned entities in this table because their credit ratings are heavily influenced by their government ownership status.

311 Testimony of Susan Abbott, Exhibit 57.05, page 8, lines 148-150.
312 Ibid. page 16, line 317 to page 17, line 319.

Table 12. Credit Rating Metrics

| Segment or Utility | Actual Debt Rating(s) | Provider | EBIT Interest Coverage | FFO / Debt (%) | FFO Coverage |
|---|---|---|---|---|---|
| AltaLink[313] | A- Stable | S&P | 1.7 | 11.1 | 3.0 |
| AltaLink[314] | A Negative Trend | DBRS | 2.07 | | |
| AltaLink Investments L.P.[315] (Parent of AltaLink) | BBB Negative Outlook | DBRS | 1.53 | 10.5[316] | |
| Fortis Inc.[317] | A- | S&P | 2.2 | 11.5 | 2.9 |
| FortisAlberta[318] | A (low) | DBRS | 2.03 | | |
| FortisAlberta[319] | A- | S&P | 2.3 | 14.3 | 4.2 |
| CU Inc.[320] | A | S&P | 2.7 | 18.7 | 3.6 |
| CU Inc.[321] | A (high) | DBRS | 2.38 | | |

348. The Commission observes from the above table that EBIT coverage ratios of approximately 2.0 to 2.3 appear to be sufficient to obtain credit ratings in the lower A range.

349. EPC submitted that based on S&P guidelines, an interest coverage ratio of 2.3 to 2.8 is required to maintain an A credit rating for "S&P business risk positions 2 to 3" which would be applicable to the distribution business of EPC, and an interest coverage ratio of 1.8 to 2.3 times is required for the lower risk "S&P business risk position of 1 to 2" which would be applicable to the transmission business of EPC. The "business risk positions" to which EPC referred, are business risk rankings formerly employed by S&P. S&P no longer publishes business risk positions. Nevertheless, the Commission observes that if S&P were still using the guidelines cited by EPC, it appears that all of the utilities listed in Table 7 (all of which have investment grade ratings) would be considered in a lower risk category given that their EBIT coverage ratios range from 1.7 to 2.7. In the case of AltaLink Investments L.P., DBRS has assigned a credit rating of BBB with a negative outlook where the EBIT coverage ratio is 1.53 times and the "cash flow to debt" (a term used by DBRS that appears to be equivalent to FFO/Debt) is 10.5 percent. This gives the Commission some indication that the lower end of the EBIT coverage range necessary to maintain a credit rating in the A range is approximately 1.8.

350. Below, the Commission reviews its analysis of the sensitivity of three key credit rating metrics to changes in the equity ratio. The Commission notes that the credit rating metrics are not very sensitive to changes in the ROE. Credit metrics are more sensitive to the amount of debt and equity in the capital structure than they are to the return on equity.

### 6.3.1 EBIT Interest Coverage Ratio

351. The Commission has calculated and set out in Table 13 below, interest coverage ratios that would result from different equity ratios assuming an embedded cost of debt of 6.5 percent,

313 Exhibit 57.06, pages 25 to 35 of 83, S&P credit report dated May 9, 2008.
314 Exhibit 57.06, AltaLink Minimum Filing Requirements, DBRS credit report of May 28, 2008.
315 Exhibit 57.06, AltaLink Minimum Filing Requirements, DBRS credit report dated May 28, 2008.
316 DBRS described this number as measuring cash flow/debt, which appears to be the same as FFO/Debt.
317 Exhibit 53.05, S&P credit report October 25, 2007 and Fortis Inc. Balance Sheet, page 107 of 283.
318 Exhibit 53.05 FortisAlberta Minimum Filing Requirements, section 4, DBRS credit report, May 30, 2008.
319 Exhibit 53.05 FortisAlberta Minimum Filing Requirements, section 4, S&P credit report, March 26, 2008.
320 Exhibit 50.02, CU Inc. S&P report dated October 26, 2007.
321 Exhibit 50.02, CU Inc. DBRS report dated May 13, 2008.

an ROE of 8.75 percent (the 2009 placeholder level) and assuming an income tax rate of 29 percent.[322] The assumed debt cost is conservative for 2009 because, according to the utility reports on finances and operations provided in the minimum filing requirements, the average cost of debt in 2007 was 6.22 percent.

**Table 13. EBIT Interest Coverage Ratios Compared to Equity Ratios**

| Equity Ratio (%) | EBIT Interest Coverage |
|---|---|
| 30 | 1.8 |
| 31 | 1.9 |
| 32 | 1.9 |
| 33 | 1.9 |
| 34 | 2.0 |
| 35 | 2.0 |
| 36 | 2.1 |
| 37 | 2.1 |
| 38 | 2.2 |
| 39 | 2.2 |
| 40 | 2.3 |
| 41 | 2.3 |
| 42 | 2.4 |
| 43 | 2.4 |
| 44 | 2.5 |
| 45 | 2.6 |

352. Table 13 shows that at a 6.5 percent cost of debt, the minimum equity ratio to achieve a 2.0 EBIT coverage ratio is 34 percent. The table also shows that to achieve an EBIT coverage ratio of 2.3 with a 6.5 percent embedded debt cost would require a minimum equity ratio of 40 percent.[323] The Commission has compared the results shown in Table 13 to the results shown in Table 9 of EUB Decision 2004-052[324] and observes that the equity ratio required in 2004 to obtain a given EBIT coverage ratio is lower than the equity ratio required today to achieve the same EBIT coverage ratio. The equity ratio required today is higher than in 2004 because income tax rates and allowed ROE declined during the period. For example, achieving an EBIT coverage ratio of 2.0 in 2004 at a 6.5 percent embedded cost of debt would have required a 30 percent equity ratio, whereas in 2009 it would require an equity ratio of 34 percent. The Commission recognizes that lower debt costs would lower the required increase in the equity ratios. Testimony given during the hearing indicated that the average cost of debt has declined since 2004 which would somewhat offset the required increase in the equity ratios indicated here.

322 Transcript, page 1870.

323 The Commission recognizes that the required equity ratio to achieve the interest coverage levels in the table would be somewhat higher in the presence of CWIP or when the effective tax rate is lower than 29 percent due to the Commission's use of the flow-through tax method for revenue requirement purposes in the case of some utilities.

324 EUB Decision 2004-052, Table 9 entitled Pretax Interest Ratios at Varying Embedded Debt Costs, shown at page 41.

### 6.3.2 Funds From Operation/Debt Ratio

353. The Commission has also calculated, and set out in Table 14 below, the ratio of the Funds From Operations (FFO) (net income plus depreciation) divided by debt that would result[325] at different equity ratios assuming an ROE of 8.75 (the 2009 placeholder level) and assuming a range of depreciation rates (as a percentage of invested capital) from 4 percent to 9 percent based on actual depreciations rate results calculated from the 2007 reports on finances and operations. These range from 4.8 percent to 8.5 percent and average 6.0 percent.

**Table 14. Funds From Operations to Debt Compared to Equity Ratios**

| Depreciation Rate | 4.00% | 5.00% | 6.00% | 7.00% | 8.00% | 9.00% |
|---|---|---|---|---|---|---|
| Equity Ratio (%) | | | | | | |
| 30 | 9.5 | 10.9 | 12.3 | 13.8 | 15.2 | 16.6 |
| 31 | 9.7 | 11.2 | 12.6 | 14.1 | 15.5 | 17.0 |
| 32 | 10.0 | 11.5 | 12.9 | 14.4 | 15.9 | 17.4 |
| 33 | 10.3 | 11.8 | 13.3 | 14.8 | 16.3 | 17.7 |
| 34 | 10.6 | 12.1 | 13.6 | 15.1 | 16.6 | 18.1 |
| 35 | 10.9 | 12.4 | 13.9 | 15.5 | 17.0 | 18.6 |
| 36 | 11.2 | 12.7 | 14.3 | 15.9 | 17.4 | 19.0 |
| 37 | 11.5 | 13.1 | 14.7 | 16.3 | 17.8 | 19.4 |
| 38 | 11.8 | 13.4 | 15.0 | 16.7 | 18.3 | 19.9 |
| 39 | 12.2 | 13.8 | 15.4 | 17.1 | 18.7 | 20.3 |
| 40 | 12.5 | 14.2 | 15.8 | 17.5 | 19.2 | 20.8 |
| 41 | 12.9 | 14.6 | 16.3 | 17.9 | 19.6 | 21.3 |
| 42 | 13.2 | 15.0 | 16.7 | 18.4 | 20.1 | 21.9 |
| 43 | 13.6 | 15.4 | 17.1 | 18.9 | 20.6 | 22.4 |
| 44 | 14.0 | 15.8 | 17.6 | 19.4 | 21.2 | 22.9 |
| 45 | 14.4 | 16.3 | 18.1 | 19.9 | 21.7 | 23.5 |

354. Table 14 shows that when the annual depreciation expense as a percentage of invested capital is equal to the utility average of 6 percent, minimum equity ratios in the range of 30 to 36 percent will achieve FFO/Debt percentages of 11.1 to 14.3, which Table 12 shows is associated with credit ratings in the lower A range.[326]

### 6.3.3 Funds From Operations Coverage Ratio

355. The Commission has calculated, and set out in Table 15, the coverage ratio of the Funds From Operations (net income plus deprecation) divided by interest expense that would result at different equity ratios and depreciation rates assuming an ROE of 8.75 percent (the 2009 placeholder level) and an embedded interest cost of 6.5 percent.

325 The Commission recognizes that this is theoretical since it omits consideration of CWIP (which lowers the FFO/ debt ratio when present) and does not consider that some utilities actually collect more taxes than paid in cash which increases the FFO/Debt ratio.

326 This omits consideration of CWIP or cash flows created by positive or negative differences between tax collected and tax paid.

Table 15. Funds From Operations Coverage Compared to Equity Ratios

| Depreciation Rate | 4.00% | 5.00% | 6.00% | 7.00% | 8.00% | 9.00% |
|---|---|---|---|---|---|---|
| Equity Ratio (%) | | | | | | |
| 30 | 2.46 | 2.68 | 2.90 | 3.12 | 3.34 | 3.55 |
| 31 | 2.50 | 2.72 | 2.94 | 3.17 | 3.39 | 3.61 |
| 32 | 2.54 | 2.76 | 2.99 | 3.22 | 3.44 | 3.67 |
| 33 | 2.58 | 2.81 | 3.04 | 3.27 | 3.50 | 3.73 |
| 34 | 2.63 | 2.86 | 3.09 | 3.33 | 3.56 | 3.79 |
| 35 | 2.67 | 2.91 | 3.14 | 3.38 | 3.62 | 3.86 |
| 36 | 2.72 | 2.96 | 3.20 | 3.44 | 3.68 | 3.92 |
| 37 | 2.77 | 3.01 | 3.26 | 3.50 | 3.74 | 3.99 |
| 38 | 2.82 | 3.07 | 3.31 | 3.56 | 3.81 | 4.06 |
| 39 | 2.87 | 3.12 | 3.37 | 3.63 | 3.88 | 4.13 |
| 40 | 2.92 | 3.18 | 3.44 | 3.69 | 3.95 | 4.21 |
| 41 | 2.98 | 3.24 | 3.50 | 3.76 | 4.02 | 4.28 |
| 42 | 3.04 | 3.30 | 3.57 | 3.83 | 4.10 | 4.36 |
| 43 | 3.10 | 3.37 | 3.63 | 3.90 | 4.17 | 4.44 |
| 44 | 3.16 | 3.43 | 3.71 | 3.98 | 4.26 | 4.53 |
| 45 | 3.22 | 3.50 | 3.78 | 4.06 | 4.34 | 4.62 |

356. It appears from Table 15 that when the annual depreciation expense as a percentage of investment capital is equal to the utility average of 6 percent, a minimum equity ratio of 33 percent is required to achieve an FFO coverage ratio of at least 3, which Table 7 shows is the minimum FFO coverage associated with credit ratings in the lower A range.

### 6.4 Credit Rating Metric Conclusions

357. The credit metric analysis of relatively pure-play Canadian utilities indicates that in order to target a credit rating in the A range: (i) the minimum equity ratio for Alberta Utilities should be 34 percent based on EBIT analysis, (which is 1 percentage point higher than the existing level awarded to transmission companies), 30 to 36 percent based on FFO/Debt analysis and 33% based on FFO interest coverage analysis; (ii) as a result of lower income tax rates and lower ROEs, a 4 percentage point equity ratio increase would be required to maintain credit metrics at the same level as the 2004 levels; and (iii) the 4 percentage points equity ratio increase would be offset to some degree by the lower debt costs in 2009 versus 2004.

### 6.5 Equity Ratios and Actual Credit Ratings

358. This section examines the actual credit ratings achieved by Canadian regulated utilities and the equity ratios associated with such credit ratings. The Commission considers that this information provides important factual evidence regarding the equity ratios required for a regulated utility to achieve its actual reported credit ratings. The following table has been prepared by the Commission from information on the record to assist in the analysis. In the table, the Commission has included utilities that are comparable to the utilities regulated by the Commission and that raise their debt independently of an affiliate and for which credit information was available on the record. The Commission did not include government-owned entities.

**Table 16. Summary of Canadian Utility Credit Ratings and Equity Ratios**

| Segment or Utility | Actual Debt Rating(s) | Provider | Equity % | Nature of Rating. | Nature of Business |
|---|---|---|---|---|---|
| AltaLink[327] | A- Stable | S&P | 36.3 | Stand-alone | fully regulated |
| AltaLink[328] | A Negative Trend | DBRS | 38.4 | Stand-alone | fully regulated |
| AltaLink Investments L.P.[329] (Parent of AltaLink) | BBB Negative Outlook | DBRS | 27.2 | Stand-alone | fully regulated |
| Fortis Inc.[330] | A- | S&P | 32.9 | Stand-alone | Largely regulated |
| FortisAlberta[331] | A (low) | DBRS | 39.5 | Stand-alone | fully regulated |
| FortisAlberta[332] | A- | S&P | 36.4 | Stand-alone | fully regulated |
| CU Inc.[333] | A | S&P | 41.0 | Rating factors in parent support | fully regulated |
| CU Inc.[334] | A (high) | DBRS | 39.1 | Stand-alone | fully regulated |
| Newfoundland Power[335] | A | DBRS | 44.1 | unknown | fully regulated |

359. Table 16 shows that the actual equity ratios of the companies with a credit rating of A- or better range from 32.9 percent to 44.1 percent with a mid point of 38.5 percent.

360. Other information about equity ratios and related credit ratings was provided on the record by Dr. Neri, on behalf of EPC. He submitted that based on his "Canadian Wires-only Peer Group," the median credit rating was "A" and the actual equity ratios ranged from 38.1 percent to 59.6 percent with the median for the group being 44.1 percent[336] (and the midpoint being 48.8 percent). The Commission notes however that Dr. Neri's seven utilities included four government-owned utilities (Hydro One, Hydro Ottawa Holdings, Toronto Hydro and Viridian Corporation). The Commission agrees with those parties (including utilities) that expressed doubts about the usefulness of data that includes the equity ratios and the credit ratings of government-owned utilities for the purposes of a proceeding dealing with investor-owned utilities.[337] Therefore, the Commission does not consider Dr. Neri's equity ratio range to be representative of stand-alone investor-owner utilities.

361. As set out in Table 11, the utilities have applied for equity ratios ranging from 38 percent (AltaLink and ATCO Electric Transmission) to 46 percent (AltaGas) and argued that these equity ratios are needed to ensure credit ratings in the A range.

327 Exhibit 57.06, pages 25 to 35 of 83, S&P credit report dated May 9, 2008, indicates a debt /(debt and equity) ratio of 63.7 percent and states that "[h]owever, the company does carry C$200 million in goodwill on its balance sheet; a more conservative measure of leverage relative to rate base is about 70%."

328 Exhibit 57.06, AltaLink Minimum Filing Requirements, DBRS credit report of May 28, 2008.

329 Exhibit 57.06, AltaLink Minimum Filing Requirements, DBRS credit report dated May 29, 2008, AILP's consolidated debt to capital is indicated as 72.8 percent (and the Commission notes that this is with no adjustment for goodwill).

330 Exhibit 53.05, S&P credit report October 25, 2007 and Fortis Inc. Balance Sheet, page 107 of 283.

331 Exhibit 53.05, FortisAlberta Minimum Filing Requirements, section 4, DBRS credit report, May 30, 2008.

332 Exhibit 53.05, FortisAlberta Minimum Filing Requirements, section 4, S&P credit report, March 26, 2008.

333 Exhibit 50.02, CU Inc. S&P report dated October 26, 2007.

334 Exhibit 50.02, CU Inc. DBRS report dated May 13, 2008.

335 Exhibit 55.01, Evidence of Dr. Neri, Schedule 1.

336 Exhibit 55.01, Evidence of Dr. Neri, page 26 of 26.

337 Dr. Neri also included a DBRS credit rating for Newfoundland Power and referenced its credit reports and financial statements.

362. In conducting its analysis, the Commission has observed that credit rating agencies typically adjust the debt/equity ratios of companies to account for items such as asset retirement obligations and capitalized leases. In some cases, adjustments are also made for goodwill. Goodwill on the balance sheet of a utility company may arise when a utility is purchased by another entity at an amount that exceeds its rate base value. The results of these adjustments are important to consider for utility companies because utility regulators do not award a rate of return on goodwill. In the case of TransCanada Pipelines the Moody's credit rating[338] focused on a debt or equity ratio excluding goodwill. As noted in footnote 328, in the case of AltaLink, S&P indicated that after excluding goodwill from the balance sheet "a more conservative measure of leverage to rate base is approximately 70 percent" (30 percent equity).[339] As shown in Table 11, AltaLink has an equity ratio of 36.3 percent (according to S&P) and 38.4 percent (according to DBRS) and has a credit rating of A- stable (S&P) and A with negative trend (DBRS). As noted in footnote 328, S&P subtracted $200 million in goodwill from AltaLink's balance sheet thereby estimating an equity ratio of 30 percent which is 3 percentage points lower than the awarded equity ratio (even though AltaLink on an unadjusted basis has an equity ratio above its awarded 33 percent).

363. In the same table DBRS indicates that FortisAlberta had an equity ratio of 39.5 percent and had a credit rating of A (low). S&P indicated an equity ratio of 36.4 percent and an A- credit rating for FortisAlberta. This compares to an awarded equity ratio of 37 percent. S&P indicated in its FortisAlberta credit report provided in Exhibit 53.05, that if an asset retirement obligation is treated as debt and if capitalized operating leases are considered then the debt to total capital ratio is 70 percent (which implies a 30 percent equity level). This adjustment does not include any reduction for goodwill similar to the reduction S&P discussed for AltaLink. If such an adjustment were made, the FortisAlberta equity ratio would be 27.8 percent,[340] 9 percentage points below its awarded equity ratio.

364. These observations suggest that if AltaLink and FortisAlberta (or other utilities) had not had goodwill on their balance sheets, then their equity ratios would have been somewhat lower than their current levels but would still have been sufficient to generate financial metrics necessary to maintain their current credit ratings.

### 6.6 Ranking Risk by Regulated Sector

365. In 2004, the EUB ranked the riskiness of the various utility sectors in Alberta based on an analysis of business risk. Business risk affects the perceived uncertainty in future operating earnings and hence determines the capacity for a business to be financed with debt as opposed to equity. Credit rating agencies take into account business risks, and therefore the equity ratios associated with the credit ratings of various utilities provide a good indication of the market's view of the equity ratios required.

366. A number of witnesses commented on the relative risk of the various utility sectors. Dr. Booth expressed the view that electric transmission remains the lowest risk.[341] Ms. Abbott,

338 Exhibit 52.03, page 78 of 348, Moody's credit rating report.

339 Exhibit 57.06, S&P Credit Report dated May 9, 2008.

340 The Commission calculated the adjusted equity ratio from page 7 of the May 30, 2008 DBRS credit report by excluding goodwill i.e. (460-189)/(460-189+696+8) =0.280.

341 Booth Revised Evidence, Exhibit 292.03, page 62, lines 13-19, pages 57-59.

appearing for AltaLink, stated that transmission and distribution companies are regarded as having similar business risk."[342]

367. Mr. Johnson, witness for Calgary, submitted that the least risky entities are the electric transmission companies AltaLink and ATCO Electric Transmission. Mr. Johnson rated gas and electric distribution as slightly more risky than electric transmission and the municipal owned companies more risky than gas and electric distribution companies. Mr. Johnson also stated that ATCO Pipelines (the only gas transmission entity regulated by the Commission) has significantly less risk now than in 2004 due to its proposed integration with NGTL, and if the agreement is implemented, Mr. Johnson states that ATCO Pipelines' risk will be similar to that of NGTL[343] (which is no longer regulated by the Commission but which was considered by the Board to have less risk than ATCO Pipelines in 2004).

368. The UCA stated that the business risk of gas transmission is low-moderate although somewhat elevated since 2004 due to an increase in supply risk. The UCA also submits that the business risk of gas distribution is low to moderate and similar to 2004 with the exception of lower operating leverage risk resulting from the introduction of a weather deferral account for ATCO Gas.[344]

369. Ms. McShane compared the utilities to industry sector-specific benchmarks for ranking purposes.[345] She rates AE Transmission, AE Distribution, and ATCO Gas as all having similar business risk to the industry benchmark. Ms. McShane rates ATCO Pipelines as having higher business risk relative to its sector-specific benchmark.[346]

370. The Commission observes that there is a general consensus on the rank ordering of risk by sector. The electric transmission sector is considered to have the least risk. No party argued otherwise and the Commission agrees.

371. The Commission also finds in general that the electricity distribution segment is slightly more risky than electricity transmission. The Commission agrees with ATCO that ATCO Gas has a similar level of business risk compared to electric distribution companies. The Commission is persuaded that due to its small size, AltaGas is more risky than ATCO Gas. The Commission agrees with ATCO that ATCO Pipelines (transmission) is more risky than ATCO Gas (distribution).

### 6.7 Company-Specific Considerations

372. The Commission now turns to a consideration of adjustments to the equity ratios of individual companies based on their specific business risks.

#### 6.7.1 Adjustment for Non-taxable Status

373. In Decision 2004-052 the EUB approved a 2 percent increment in the common equity ratio for non-taxable utilities. The Board said, at page 45 of Decision 2004-052:

342 Exhibit 170.01,UCA-AML-19(c).
343 Exhibit 180.02 and 180.03, Evidence of Mr. Johnson, pages 2-3.
344 UCA Argument, Exhibit 387.01, pages 62-64.
345 Exhibit 50.01, McShane Evidence, Section 4.0, page 15.
346 Exhibit 50.01, McShane Evidence, Section 4.0, page 3, table 1.

> The Board agrees that a non-taxable entity has a higher volatility of earnings than an otherwise equivalent taxable company, arising from the lack of an income tax component in its forecast revenue requirement. The Board notes that there was no disagreement that the absence of taxation, while lowering costs, increases the volatility of earnings.

374. This issue was discussed by Commissioner Kolesar and Ms. McShane as follows:

> Q So the logic of giving the non tax-paying company an extra 2 percent of equity thickness is because the tax-paying company is actually collecting in its rates the expected income tax. So it kind of gives them that extra layer of buffer so that on an after-tax basis, they would -- or sorry, on a pretax basis, they actually have more cash flow that they could use to pay debt with. That's, I believe, the fundamental logic of why they get that – why the non tax-paying company gets the extra 2 percent because they don't have the benefit of that additional buffer.
> MS. McSHANE: What you say is true, and if I go back to Decision 2004-052, at the time of the decision, we had basically three -- what I'll call three types of utilities: Non taxable, fully taxable and AltaLink, which was semi taxable.[347]

375. ENMAX and EPCOR submitted that they should continue to be awarded an additional 2 percent of equity to account for their status as a non-taxable utility. ENMAX submitted that the EUB's previous decision remains valid today and that an additional 2 percent equity should still be awarded to account for the higher business risks and earnings volatility of a non-taxable entity.[348]

376. The UCA's witnesses Drs. Kryzanowski and Roberts did not support a 2 percent addition of equity thickness for non-taxable utilities. The UCA argued that an adjustment to equity thickness suffers from two major flaws:

> First, it is based on the same overly simplistic view of financial markets that they (Kryzanowski and Roberts) debunked in the earlier discussion of ratio guidelines employed by rating agencies. S&P itself neither states nor acts as if it believed that having a key ratio below a certain target level (due to non-taxable status or other reasons) is grounds for a downgrade. Second, the UCA's witnesses demonstrate that there is a positive side to non-taxable status as it can lead to greater upside when a utility overearns its allowed returns.[349]

377. Drs. Kryzanowski and Roberts also argued that utilities under Alberta's regulatory regime are more likely to over-earn than under-earn. Their Schedule 2.10, Average Actual and Approved Return on Equity for Applicant Utilities 2001–2007, showed that out of five non-taxable utilities three of them over-earned (actual ROE was greater than allowed ROE.).

378. The CCA supports the arguments of the UCA and states in its Reply that it does not support an increase in equity ratio for non-taxable status utilities.[350] The CCA also submitted that there is benefit to the utility from over earning because there are no associated taxes. As a result the non-taxable utility would earn a greater return than a taxable utility when it earns more than its approved rate of return.[351] Calgary also submits in its Argument that an adjustment for

347 Transcript, page 1872, line 19.
348 EPC Argument, Exhibit 385.02, page 15.
349 Evidence of Drs. Kryzanowski and Roberts, Exhibit 179.02, page 240, lines 1-24.
350 CCA Reply Argument, page 14, paragraph 52.
351 CCA Reply Argument, page 14, paragraph 52.

non-taxable utilities is likely not needed and its witness, Mr. Johnson, went on to question whether the 2 percent adjustment should be changed in light of lower corporate tax rates.[352]

379. Dr. Vander Weide, stated in his evidence that he agreed with an additional 2 percent deemed common equity that the Alberta regulators have been recognizing. Dr. Vander Weide states:

> I agree with the EUB's decision that non-taxable utilities should have higher deemed equity ratios because, other things equal, they have greater variability in net income and return on equity and lower interest coverage ratios than fully taxable utilities.[353]

380. Dr. Vander Weide further states:

> Other things equal, a utility whose revenue requirement does not include an income tax allowance (i.e., a Non-Taxable Utility) has a lower interest coverage ratio, higher variability in operating income, and higher variability in return on equity.[354]

381. Fortis submitted that, due to combined effects of its flow-through tax approach adopted for rate making and its large capital programs, it anticipates being a non-taxable entity until at least 2013.[355] Fortis submits that the rationale applied from Decision 2004-052 for a utility to be considered for non-taxable applies to Fortis and that logic, consistency, and fairness indicate that the 2 percent addition to equity thickness should apply to Fortis in its current situation.[356]

382. The CCA disagrees with granting the two percent increment to Fortis. The CCA submits that Dr. Vander Weide was not asked to provide an opinion on this and considers that Fortis has not provided expert evidence to justify its position on non-taxable status.[357] The CCA stated in Argument that it is alarmed over the use of non taxable status as an argument for increased risk of the utility and a higher equity ratio requirement.

383. The Commission agrees that entities with tax exempt status have a higher volatility of earnings than otherwise equivalent taxable companies because of the absence of an income tax component in their forecast revenue requirements. There was no disagreement among participants in the proceeding that while income tax exempt status lowers a company's costs, it increases the volatility of earnings and decreases interest coverage ratios. Therefore, the Commission will continue to add two percentage points to the equity ratios of income tax exempt utilities.

384. The Commission agrees with Fortis that since it is currently non-taxable and expects to be so at least for the near-term future, it too qualifies for the addition of two percentage points to its equity ratio. This status would change if Fortis became an income tax paying entity or if the Commission were to change from the flow through method of accounting for income taxes for revenue requirement purposes to the normalized tax or another similar method in the future.

352 Transcript. page 3658, lines 3-8.
353 Exhibit 56.04, Supplemental Evidence Dr. Vander Weide, pages 2-3.
354 Exhibit 282.01, Reply Evidence Dr. Vander Weide, pages 46-51.
355 Exhibit 53.03, Fortis Evidence, pages 1-2.
356 Fortis Argument, Exhibit 382.03, pages 2-11.
357 CCA Argument, Exhibit 391.01, page 29.

### 6.7.2 ATCO Gas 2008 Capital Structure

385. ATCO Gas's equity ratio for 2008 remains to be determined in this proceeding. In Argument, ATCO explained how it had filed its evidence as follows:

> ATCO Gas is requesting a common equity ratio of 40% with an ROE of 11.0% for 2009. The same factors which support an increase in AG's common equity ratio for 2009 are applicable to 2008 as discussed in Ms. McShane's evidence attached as Appendix F to the ATCO Utilities' application (wherein a common equity ratio of 40% - at the 2008 formula ROE - is requested).[358]
>
> …..the ATCO Utilities present their own analysis of what a Fair Return for 2009 should be for each utility sector; and what an appropriate capital structure should be for 2008 for ATCO Gas.[359]

386. The UCA stated that it had specifically studied the required equity ratio for ATCO Gas (ATCO Gas and ATCO Pipelines) for 2008.[360] In Argument the UCA stated:

> To ensure fairness across applicant utilities to this proceeding, the UCA recommends that the Commission apply the 2004 Generic Cost of Capital decision to these two utilities. In other words, it would be "consistent to leave it where it is now just for 2008".[361]

387. The Commission has examined ATCO Gas's request to adjust the 2008 equity ratio from 38 percent to 40 percent. The Commission recognizes that the effects of the financial crisis were beginning to be felt during 2008 and that, as a result, some increase in ATCO Gas's equity ratio would have been warranted. Therefore, the Commission allows an equity ratio of 39 percent for ATCO Gas in 2008.

### 6.7.3 Adjustments for Smaller Utilities

388. During the proceeding AltaGas had observed that due to its small size it was exposed to greater business risk than larger companies which operate in the same sector. In its Evidence, AltaGas stated:

> The AUI evidence in the case does not compare its business risks in 2004 to those experienced today. It reasonably and properly compares the risk of AUI relative to other utilities. As a result of its small size, regulatory risk, service territory (operating) risk and financial market risks, the overall risk of AUI is higher than its larger utility peers, justifying a higher equity component of its capital structure and a higher return.

389. AltaGas also submitted that smaller firms have greater difficulty accessing public debt and, as a result, they often must rely on short-term loans from banks. This makes small firms more sensitive to fluctuations in interest rates than larger companies that can access longer term debt and exposes smaller companies to greater interest-rate risk, and other financial risks.[362] The Commission agrees that AltaGas's small size continues to warrant a higher equity ratio compared to ATCO Gas.

358 ATCO Argument, Exhibit 390.02, page 98.
359 ATCO Argument, Exhibit 390.02, page 1.
360 Transcript, page 2947.
361 UCA Argument, Exhibit 387.01, page 97.
362 Exhibit 58.02, page 158, lines 11-15.

### 6.7.4 ATCO Pipelines' System Integration with NGTL

390. In August 2008, ATCO Pipelines entered into a memorandum of agreement for the integration of its system with that of NGTL.[363] During the course of the proceeding, Mr. Jansen stated that definitive agreements had been signed subject to customer and regulatory approval. A number of parties discussed how the agreement might affect the business risks of ATCO Pipelines. Calgary submitted that the agreement reduces ATCO Pipelines' risk significantly because it significantly reduces competition between ATCO Pipelines and NGTL.[364] In light of the agreement, both Dr. Booth and Drs. Kryzanowski and Roberts have made two separate capital structure recommendations for ATCO Pipelines, one with integration (33 and 34 percent respectively) and one without integration (37 and 42 percent respectively).[365]

391. ATCO responded in Reply Argument that it is difficult to ascertain with any degree of confidence what the risk profile of ATCO Pipelines would be post-integration. ATCO went on to say that it is unreasonable to leap to conclusions about the business risk of ATCO Pipelines after integration and that the only thing which is certain is that there will be change.[366]

392. The Commission agrees with ATCO that until the agreement has been finalized and has received regulatory approvals, it is difficult to determine what changes to ATCO Pipelines' risks might occur. Therefore, the Commission will not make adjustments for changes in risk that might result from the agreement. The Commission will re-evaluate business risk following implementation of the agreement.

### 6.7.5 ATCO Gas 2009 Capital Structure

393. In Decision 2008-113,[367] the Commission approved a weather deferral account for ATCO Gas effective January 1, 2008. In her evidence, Ms. McShane for ATCO concluded that business risk for ATCO Gas had not changed since 2004 because any reduction in risk from a weather deferral account has been offset by other risks. She stated:

> Any reduction in risk due to the proposed weather deferral account is offset by increasing cost recovery risks associated with declining customer usage and a high growth economy.[368]

394. During the proceeding, UCA stated that the weather deferral account approved for ATCO Gas has reduced its level of risk since the last Generic Cost of Capital Proceeding.[369] Drs. Kryzanowski and Roberts rate ATCO Gas's operational risk as low-moderate and also note that it has been reduced by the approval of a weather deferral account.[370]

395. Bond rating agencies also view weather deferral accounts as risk-reducing tools. Drs. Kryzanowski and Roberts referred to a DBRS report as follows:

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363 Exhibit 50.01, Section 4.0, Evidence of Ms. McShane, page 45.
364 Calgary Argument, Exhibit 386.02, page 21.
365 Evidence of Drs. Kryzanowski and Roberts, Exhibit 179.02, page 6; CAPP Argument, Exhbit 388.02, page 94.
366 ATCO Reply Argument, pages 41-42.
367 Decision 2008-113 - ATCO Gas 2008-2009 General Rate Application Phase I (Application No. 1553052, Proceeding ID. 11) (Released: November 13, 2008).
368 Exhibit 50.02, Appendix F, Capital Structure for ATCO Gas, Kathleen C. McShane, page 3.
369 Exhibit 178.02, Evidence of B. Marcus, page 20.
370 UCA Argument, Exhibit 387.01, page 62.

Writing prior to its approval, DBRS states the rationale for a weather deferral account as a risk-reducing tool:

> The Company's earnings and cash flows, particularly at ATCO Gas where residential customers account for nearly 50% of volume distributed, are sensitive to the weather. Significant changes in weather from one year to the next can impact earnings and cash flows. A 10% change in normal temperatures impacts annual earnings by approximately $10 million. ATCO Gas is seeking approval from the AUC to set up a deferral account mechanism that would, if approved, eliminate the impact of temperature on ATCO Gas earnings.[371]

396. Drs. Kryzanowski and Roberts conclude that this indicates that DBRS would consider ATCO Gas's weather deferral account to reduce its risk.[372]

397. During the proceeding Dr. Vilbert observed that weather risk is not a risk that affects the cost of capital and that only non-diversifiable business risks should be reflected in cost of capital determinations.[373] CAPP's expert Dr. Booth agrees with Dr. Vilbert and stated that weather is the "ultimate" in a completely diversifiable risk.[374]

398. The Commission considers that weather risk is diversifiable for equity investors but is not diversifiable for debt investors. Debt returns to investors are capped at the contracted interest rates and do not benefit from potential unexpected profits (or losses) than can accrue to equity. Therefore, debt investors have lower diversification opportunities. The Commission finds that a weather deferral account does reduce business risk. In the case of ATCO Gas specifically, the Commission agrees that its business risks have been reduced and therefore a reduction in its equity ratio is warranted.

### 6.7.6 Transmission Facility Owners and Section 42 of the *Transmission Regulation*

399. Transmission facility owners (TFO) are facing an unexpected period of substantial capital investment and have indicated that they need to be in a position to attract capital to finance these large construction projects. AltaLink states in its Argument that:

> With the introduction of the AESO's New 10 Year Transmission Plan and with the introduction of Bill 50 in June of 2009, AltaLink's capital estimates proved to be seriously understated. Under Bill 50, the need for critical transmission infrastructure will be determined by the Province including mandating the need for two HVDC lines between Edmonton and Calgary and two 500 kV lines between Fort McMurray and Edmonton.[375]

400. Ms. McShane as well as Drs. Kryzanowski and Roberts have stated that ATCO Electric's business risk has increased because of the risks associated with the forthcoming large

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371 Exhibit 179.02, Evidence of Drs. Kryzanowski and Roberts, page 92, DBRS Rating Report, CU Inc., May 13, 2008, page 3.
372 Exhibit 179.02, Evidence of Evidence of Drs. Kryzanowski and Roberts, page 92, DBRS Rating Report, CU Inc., May 13, 2008.
373 AltaGas Argument, Exhibit 384.01, page 25, lines 9-12.
374 Transcript, pages 3630-3631
375 AltaLink Argument, Exhibit 389.03, page 2.

construction builds.[376] During the Proceeding parties observed that the provincial government had enacted section 42 of the *Transmission Regulation* to deal with the challenges that might be faced by TFOs building large transmission projects to support Alberta's competitive electricity generation market. Section 42 states:

> In addition to the matters taken into account by the Commission under section 122 of the [Electric Utilities] Act, when considering an application for approval of a TFO tariff, the Commission must consider that it is also in the public interest to provide consumers the benefit of unconstrained transmission access to the competitive generation market
>
> (a) by providing sufficient investment to ensure the timely upgrade, enhancement or expansion of transmission facilities, and
>
> (b) by fostering a stable investment climate and a continued stream of capital investment for the transmission system.

401. During the Proceeding, the Commission heard varying perspectives of the interpretation of section 42 of the *Transmission Regulation* and the relationship between section 42 and section 122 of the *Electric Utilities Act*.

402. AltaLink argued that section 42 of the *Transmission Regulation* is to be considered as providing financial assurances in addition to section 122. In its Argument AltaLink stated:

> Section 42 is **in addition to the matters** to be taken into account by the Commission under section 122. Therefore, on its face, section 42 of the Transmission Regulation is not simply duplicative of section 122 of the *Electric Utilities Act*.[377]

403. Mr. Weismiller, company witness for ENMAX, stated at the hearing that his understanding of section 42 was that it did not add much in relation to section 122.[378] EPCOR and ATCO both stated at the hearing that as long as the applicant utility was consistently awarded a fair return then it would be able to go out and raise capital at anytime and if a fair return was awarded then no additional consideration would be required by the Commission in terms of return, increase in ROE or increase in capital structure.[379] In response to a question from Commission Counsel at the hearing, Mr. Stout of EPCOR stated:

> …and now I will get back to Section 42, which I see there is really as a reminder to the regulator and a reminder to the companies that the regulatory compact still exists, that we've gone through a cycle in transmission building of little investment, even of neglect, if you like, to one where we need to do a lot of catch-up investment and strengthen that transmission system, and it now becomes critically important that the TFOs are able to finance and gather the capital necessary to build that. But I don't see it as anything more than that. I don't see it as suggesting there should be some extra juice or extra favour in terms of return on equity or anything else. I think it simply is an underscoring of, hey, there's a regulatory compact here in times of slowdown and in times of rapid growth."[380]

376 ATCO Argument, Exhibit 390.02, page 94.
377 AltaLink Argument, Exhibit 389.03, page 26, paragraph 59.
378 Transcript, page 2603, line 25 to page 2604, line 2.
379 Transcript, page 471, line 22 to page 472, line 19 and page 1790, lines 11-25.
380 Transcript, page 471, line 22 to page 472, line 11.

404. The Commission does not interpret section 42 of the *Transmission Regulation* to require it to provide TFOs with additional returns. Rather, it is meant to provide authorization to the Commission to consider a wide range of regulatory mechanisms that could assist the TFOs in financing their transmission builds. A number of options, including an increased allowed ROE, a higher equity ratio and the inclusion of construction work in progress (CWIP) in rate base are available to TFOs to assist in the transmission builds.

405. Ms. Abbott (appearing for AltaLink as a former credit analyst) was of the opinion that the ability to include CWIP in rate base would be viewed as a positive by the credit rating agencies.[381] CWIP for a regulated utility provides an opportunity to capitalize, through an Allowance for Funds Used during Construction (AFUDC), the interest and ROE on the utility's investment in CWIP. In this manner the utility receives a non-cash return through AFUDC. The AFUDC is added to rate base and the utility receives its cash return on this cost of financing its CWIP over the life of the constructed assets.

406. Where immediate cash flow is more important to the utility than the opportunity to add to rate base through AFUDC on CWIP, the ability to put CWIP in rate base would be beneficial to a utility because it advances the non-cash AFUDC associated with the assets under construction to current cash flows for the utility. This in turn lowers the risk of the utility.

407. Counsel for AltaLink, in final Argument, stated that:

> AltaLink appreciates the Commission's interest in exploring novel approaches to addressing the cash flow issues caused by significant transmission expansion. While CWIP in Rate Base has some merit and provides some improvements in cash flow, it is not a substitute for fair return. It is AltaLink's view that more must be undertaken to fully understand CWIP in rate base.[382]

408. Accordingly, the Commission will defer any decision about inclusion of CWIP in rate base until such time as an application is made to it by a TFO. This approach is consistent with the Commission's approach in the recent AltaLink Management Ltd. TFO Tariffs decision.[383] In that decision, the Commission approved AltaLink's proposal to continue to utilize the Future Income Tax (FIT) method. Neither a 38 percent equity ratio as a placeholder nor a CWIP in rate base solution to AltaLink's credit rating concerns was awarded. The Commission stated:

> If, after the effects of the Commission's decision in the GCOC proceeding have been assessed, further measures are required to obviate the potential for a downgrade of AltaLink's credit rating, the Commission is prepared to consider the adoption of measures such as the suspension of normal CWIP accounting procedures on AltaLink's large anticipated capital program. This is the Commission's preferred method of addressing any remaining credit metric concerns identified by AltaLink in the Application because it directly addresses the fundamental cause of the cash flow problem that is impacting credit metrics.[384]

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381 Transcript, pages 396-397.
382 AltaLink Argument, Exhibit 389.03, paragraph 70.
383 Decision 2009-151 – AltaLink Management Ltd. and TransAlta Corporation 2009-2010 Transmission Facility Owner Tariffs, (Released October 2, 2009), paragraph 563.
384 Decision 2009-151, paragraph 617.

409. The Commission concludes, as stated above, that it does not interpret section 42 of the *Transmission Regulation* to require it to provide TFOs with additional returns and the Commission will defer any decision to consider regulatory mechanisms that could assist the TFOs in financing their transmission builds to such time when an application is made by a TFO.

## 6.8 Conclusion Regarding Required Capital Structures

410. The Commission has examined a number of factors that are relevant to determining required equity ratios. These include a consideration of the impacts of the financial crisis, the ranking of the utility segments based on business risk, the levels of key credit metrics that are associated with the actual credit ratings of relatively pure-play Canadian utilities, and the levels of equity ratios that are associated with the actual credit ratings of relatively pure-play Canadian utilities. Two factors that particularly impacted the electric transmission sector were also examined; the impact of CWIP and the impact of the Transmission Regulation. Finally, three factors specific to certain individual utilities were examined; the non-taxable status of a number of the utilities, the small size of AltaGas, and the competitive situation facing ATCO Pipelines.

411. Accordingly, the Commission makes the following findings:

1. The credit crisis warrants an increase in the equity ratios for all utilities to reflect increased risk and the re-pricing of risk.
2. The credit metric analysis of relatively pure-play Canadian utilities indicates that in order to target a credit rating in the A range: (i) the minimum equity ratio for Alberta Utilities should be 34 percent based on EBIT analysis, (which is 1 percentage point higher than the existing level awarded to transmission companies), 30 to 36 percent based on FFO/Debt analysis and 33 percent based on FFO interest coverage analysis; (ii) as a result of lower income tax rates and lower ROEs a 4 percentage point equity ratio increase would be required to maintain credit metrics at the same level as the 2004 levels; and (iii) the 4 percentage points equity ratio increase would be offset to some degree by the lower debt costs in 2009 versus 2004.
3. The analysis of the equity ratios of relatively pure play Canadian utilities and their actual credit ratings does not indicate that any equity ratio increase is required.
4. The business risk analysis does not indicate that there have been major changes in the relative risks of the various utilities segments. Hence, any increase in equity ratios should be relatively uniform across the sectors and individual utilities unless utility-specific considerations require otherwise.

412. After considering all of the above the Commission awards a 2 percentage point base increase in the equity ratios of the Alberta utilities. Company specific adjustments to this base increase are as follows:

**AltaLink, ATCO Electric and TransAlta**

These electric transmission utilities are awarded a 3 percentage point increase to their equity ratios. This consists of the 2 percentage point base increase discussed above plus an additional 1 percentage point increase in recognition of the impacts of the large capital additions forecast by these utilities and the resulting negative impacts on their credit metrics.

### ATCO Gas

In respect of 2008, ATCO Gas is awarded a 1 percentage point increase in its equity ratio. For 2009, it is awarded a 1 percent increase. This is based on the 2 percentage point base increase and a deduction of 1 percentage point to recognize that it now has a weather deferral account.

### FortisAlberta

As determined in section 6.7.1, FortisAlberta is awarded an additional 2 percentage points in its equity ratio since it is currently non-taxable.

**Table 17. Equity Ratio Findings**

| | Last Approved (%) | Requested (%) | 2009 (%) |
|---|---|---|---|
| **Electric and Gas Transmission** | | | |
| ATCO Electric TFO | 33 | 38 | 36 |
| AltaLink | 33 | 38 | 36 |
| ENMAX TFO | 35 | 40 | 37 |
| EPCOR TFO | 35 | 40 | 37 |
| RED Deer TFO | 35 | n.a. | 37 |
| Lethbridge TFO | 35 | n.a. | 37 |
| TransAlta | 33 | n.a. | 36 |
| ATCO Pipelines | 43 | 43 | 45 |
| **Electric and Gas Distribution** | | | |
| ATCO Electric DISCO | 37 | 40 | 39 |
| ENMAX DISCO | 39 | 44 | 41 |
| EPCOR DISCO | 39 | 44 | 41 |
| ATCO Gas | 38 | 40 | 39 |
| ATCO Gas for 2008 | 38 | 40 | 39 |
| FortisAlberta | 37 | 44 | 41 |
| AltaGas | 41 | 46 | 43 |
| **Retailers** | | | |
| EEAI | 37 | 42 | 39 |

## 6.9 Future Adjustments to Capital Structure

413. The equity ratios awarded in this Proceeding will remain in place until changed by the Commission. Individual utilities, or interveners, may apply for changes to equity ratios on the basis of significantly changed circumstances.

# 7 ADJUSTMENT FORMULA

414. Having determined the fair generic rate of return on equity for 2009, the Commission must consider how that rate of return might be adjusted in future years. One of the principal purposes of this proceeding has been to consider whether the annual adjustment formula adopted by the EUB in 2004 should be retained, and if not, whether a new formula for annual adjustments to ROE or any formula at all should be adopted by the Commission.

415. The utilities appearing at the hearing unanimously asserted that the 2004 formula is broken. Some utilities argued that the formula no longer produces a fair ROE because

Ontario Energy Board

# EB-2009-0084

# Report of the Board

## on the Cost of Capital for Ontario's Regulated Utilities

December 11, 2009

## The Role of the Comparable Investment Standard

Continued investment in network utilities does not, in itself, demonstrate that the FRS has been met by a regulator's cost of capital determination, and in particular, whether the determination of the equity cost of capital meets the requirements of the FRS. This is a particular challenge – how does the regulator determine when investment capital is not allocated to a rate regulated enterprise? These decisions are typically made within the utility/corporate capital budgeting process and rarely, if ever, broadly communicated to stakeholders. The Board notes that acquisition and divestiture activities of regulated utilities are not definitive in this regard, one way or the other, and notes that there are many reasons why investors are willing to acquire or desirous of selling utility assets, notwithstanding their view of whether an allowed ROE meets the FRS.

The primary tool available to the regulator to rectify this lack of transparency is the comparable investment standard. By establishing a cost of capital, and an ROE in particular, that is comparable to the return available from the application of invested capital to other enterprises of like risk, the regulator removes a significant barrier that impedes the flow of capital into or out of, a rate regulated entity. The net result is that the regulator is able, as accurately as possible, to determine the opportunity cost of capital for monies invested in utility works, with the ultimate objective being to facilitate efficient investment in the sector.

There are a number of specific issues relating to the comparable investment standard that the Board considers are relevant in the context of this cost of capital policy.

First, "like" does not mean the "same". The comparable investment standard requires empirical analysis to determine the similarities and differences between rate-regulated entities. It does not require that those entities be "the same".

Second, there was a general presumption held by participants representing ratepayer groups in the consultation that Canadian and U.S. utilities are not comparators, due to differences in the "time value of money, the risk value of money and the tax value of money."[15] In other words, because of these differences, Canadian and U.S. utilities cannot be comparators. The Board disagrees and is of the view that they are indeed comparable, and that only an analytical framework in which to apply judgment and a system of weighting are needed. The analyses of Concentric Energy Advisors and Kathy McShane of Foster Associates Inc. are particularly relevant in this regard, and substantially advance the issue of establishing comparability to meet the requirements of the FRS. Further, the Board notes that in the consultation session on October 6, 2009, Dr. Booth stated that it is "absolutely possible" to form a sample from a risky universe that is low risk and compare it to the universe or the population of Canadian utilities.[16] All participants agreed.

The Board notes that Concentric did not rely on the entire universe of U.S. utilities for its comparative analysis. Rather, Concentric carefully selected comparable companies based on a series of transparent financial metrics, and the Board is of the view that this approach has considerable merit. Commenting on Concentric's analysis, Union Gas noted that no one else in the consultation performed this kind of detailed analysis of U.S. comparators.[17] The use of a principled, analytical, and transparent approach to determine a low risk comparator group from a riskier universe for the purpose of informing the Board's judgment was supported by various participants in the consultation.

The PWU commented that the position taken by Dr. Booth on the question of the comparability of US utility returns is not based on an appropriate empirical foundation.[18] The PWU further commented that:

> On the other hand, it is the view of the PWU that the analysis produced by Concentric, as summarized in one of their charts presented at the conference, represents a far more comprehensive analysis of the key characteristics of distribution utilities in Ontario vs. a North American

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[15] Professor L.D. Booth. Written Comments on behalf of Consumers Council of Canada, the Vulnerable Energy Consumer's Coalition, the Industrial Gas Users Association, the Canadian Manufacturers & Exporters (CME), the London Property Management Association and the Building Managers and Owners Association of the Greater Toronto Area. September 8, 2009. p. 25.
[16] Ontario Energy Board. Transcript of Consultation Process on Cost of Capital Review. October 6, 2009. Comments of Dr. Booth at p. 60. Lines 24-26.
[17] Written Comments of Union Gas Limited. October 30, 2009. p. 14.
[18] Final Comments of the Power Workers' Union. October 30, 2009. p. 3.

> proxy group. Differences and similarities were thoroughly considered before arriving at the conclusions that based on a careful selection of like companies, a proxy group which includes US distribution utilities adheres to the Comparable Investment Standard. Moreover, Concentric was better suited to complete such as an analysis, having recognized expertise in the risks faced by both Ontario and US electricity distributors.[19]

Dr. Vander Weide indicated that since Canadian utility bonds tend to have more covenants than US utility bonds, they would receive a slightly higher credit rating. The PWU observed that it the slight variance in ratings can be attributed to specific features of debt instruments, rather than fundamental differences in the underlying business or regulatory risks faced by the utilities. This observation was also made by Ms. Zvarich of Sun Life Financial, who presented evidence that Canadian utility bonds generally have more restrictive covenants than U.S. utility bonds.[20]

The Board is of the view that the U.S. is a relevant source for comparable data. The Board often looks to the regulatory policies of State and Federal agencies in the United States for guidance on regulatory issues in the province of Ontario. For example, in recent consultations, the Board has been informed by U.S. regulatory policies relating to low income customer concerns, transmission cost connection responsibility for renewable generation, and productivity factors for 3rd generation incentive ratemaking.

Finally, the Board agrees with Enbridge that, while it is possible to conduct DCF and CAPM analyses on publicly-traded Canadian utility holding companies of comparable risk, there are relatively few of these companies. As a result, the Board concludes that North American gas and electric utilities provide a relevant and objective source of data for comparison.

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[19] Final Comments of the Power Workers' Union. October 30, 2009. p. 6.
[20] Ontario Energy Board. Transcript of Consultation Process on Cost of Capital Review. September 21, 2009. Comments of Ms. Zvarich at pp. 24 -25.

## 3.2 The Cost of Capital in Theory and Practice

### *The Cost of Capital*

The Ontario Energy Board has been engaged in the rate regulation of utilities for many years. Over this extended period, the Board notes that there continues to be any of a number of misconceptions about the cost of capital concept, particularly what the cost of capital is and why it is an important consideration.

The Board is of the view that the following points articulated by Dr. Bill Cannon in his presentation at CAMPUT's 2009 Energy Regulation Conference on July 3, 2009, are principally relevant to defining and understanding the cost of capital concept.

> At its simplest, the cost of capital is the minimum expected rate of return necessary to attract capital to an investment. The rate of return includes the income received during the time the investment is held plus any capital gain or loss, realized or accruing during this period, all as a percentage of the initial investment outlay.
>
> The cost of capital can be viewed from both: (a) a company or utility perspective; and (b) from the investor's or capital provider's perspective. From the company's perspective, the cost of capital is the minimum rate of return the company must promise to achieve for investors on its debt and equity securities in order to preserve their market values and, thereby, retain the allegiance of these investors.
>
> [There is interest] in the cost of capital...because all utilities – private or public – at some time... must raise financial capital to pay for investments, and both fairness and practical considerations dictate that the private and/or government investors who provide these capital funds must be adequately compensated. Raising capital is a competitive process. Private investors are under no obligation to buy a particular utility's securities, and government-owned utilities must compete with other government spending priorities. A utility will be able to secure new capital and replace maturing securities only if investors believe that they will be adequately rewarded for providing new capital funds. That required reward, in turn, must compensate the investors for a least two things: (1) for postponing the consumption of the goods and services that they might otherwise have enjoyed had they not made the investment; and (2) for exposing their funds to the risk that they may not

> get all their money back or not get it back as promptly as they anticipated. The reward demanded by investors is therefore a necessary cost of doing business from the utility's point of view, just as much as the cost of labour or fuel.
>
> From the viewpoint of investors as a group, however, the cost of capital can be defined more clearly and operationalized as "the expected rate of return prevailing in the capital markets on alternative investments of equivalent risk and attractiveness." There are four concepts embedded in this operational definition:
>
> First, it is *forward-looking*. Investment returns are inherently uncertain and the ex post, actual returns experienced by investors may differ from those that were expected ahead of time. The cost of capital is therefore an *expected* rate of return.[21]
>
> Second, it reflects the *opportunity cost* of investment. Investors have the opportunity to invest in a wide range of investments, so the expected rate of return from a given utility-company investment must be sufficient to compensate investors for the returns they might otherwise have received on foregone investments.
>
> Third, it is *market-determined*. This market price - expressed as the expected return per dollar of invested capital - serves to balance the supply of, and demand for, capital for the firm.
>
> And, fourth, it reflects the *risk* of the investment. It reflects the expected returns on investments in the marketplace that are exposed to equivalent risks. Another way of expressing this principle is to say that the cost of capital depends on the *use* of the capital – or, more precisely, the risk associated with the use of the funds – and not on the *source* of the funds.

In Ontario, utilities regulated by the Board in the gas and electricity sectors are structured to operate as commercial entities. As such, the rate setting methodologies used by the Board apply uniformly to all rate-regulated entities regardless of ownership. The determination of rate-regulated entities' cost of capital is no exception. It follows that the opportunity cost of capital should be determined by the Board based on a systematic and empirical approach that applies to all rate-regulated utilities regardless of ownership. The Board sees no

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[21] The word "expected" is used in the statistical sense (i.e., the probability-weighted rate of return). It does not refer to a "hoped for" or "most likely" rate of return.

compelling reason to adopt different methods of determining the cost of capital based on ownership.

### *The Equity Risk Premium Approach*

As previously indicated, the Board has determined that the ERP approach remains the most appropriate approach in the current circumstances. The ERP approach is one of four main approaches that are traditionally used by experts during regulatory cost of capital reviews to establish a fair ROE: (1) the comparable earnings approach; (2) discounted cash flow approach; (3) the capital asset pricing model; and (4) ERP approach. These methods are all used in varying degrees to formulate and/or test an opinion regarding a fair return to investors.[22] The Board's current formulaic approach is a modified Capital Asset Pricing Model methodology and ERP approach.

Each of these four main approaches has well documented strengths and weaknesses. Notwithstanding the known weaknesses of these differing approaches, the Board agrees with Ms. McShane when she states: "each of the various types of tests brings a different perspective to the estimation of a fair return. No single test is, by itself, sufficient to ensure that all three requirements of the fair return standard are met."[23]

Through the consultative process which began in February 2009 and has culminated in this report, the Board has been informed by a number of ex-post analytical approaches, including analysis of experienced ERPs on investments in Canadian utility stocks. The Board observes from these analyses that the ROE produced by various approaches can be expressed as an absolute ROE number or as an ERP over a risk-free rate. Also, the Board agrees that expressing the ROE in terms of a premium above the long-term Canada bond yield does not mean that the initial ROE needs to be estimated by using a single test or a number of tests that might be defined as ERP tests.

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[22] Ontario Energy Board. Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities. March 1997. p. 2.
[23] McShane, K., Foster Associates, Inc. Written comments on behalf of the Electricity Distributors Association. September 8, 2009. p. 2.

### *A Formulaic Approach*

The Board has used a formula-based methodology to determine the rate of ROE since 1998. The advantages identified in the 1997 Draft Guidelines remain appropriate today and include:

- Simplification of the hearing process;
- Is relatively free from conflicting interpretation and is readily understood by all participants;
- Reduces the need for complex, annual risk assessments, while still reflecting major changes in the capital markets; and
- Is capable of producing a rate of return that approximates the result which would have been produced through the traditional process.[24]

The Board also notes that a formula-based approach:

- Is transparent, resulting in predictable and consistent outcomes, and meets the needs of stakeholders broadly, particularly those in the capital market; and
- Is a practical necessity in Ontario, given the large number of rate regulated entities.

The Board also acknowledges that a formula-based ROE methodology and mechanical approaches in general, have a number of disadvantages, as identified in the 1997 Draft Guidelines:

- Establishing the initial parameters of the generic formula will have a profound influence on the potential success or failure of the process. Over time, these parameters and adjustment factors will have a cumulative or compounding effect on the

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

results of the formulaic ROE mechanism. The use of an inappropriate initial ROE will either inflate or understate subsequent rate determinations;

- The present formulaic ROE generally relies predominantly on the ERP method to the exclusion of other methods;

- Adjustment for the impact of timing differences for utilities with different year-ends is a challenge; and

- The Board's ability to make discretionary adjustments to a utility's return for the purpose of creating incentives for particular behaviours or sending signals to the marketplace may be restricted. [25]

Notwithstanding these concerns, the Board is of the view that it is appropriate to continue to use a formulaic approach to determine the equity cost of capital and that the overall advantages of the approach outweigh potential disadvantages.

### *An Empirical Foundation*

The essential elements of a formulaic approach must be empirically derived – the initial ROE, implied ERP and the adjustment factor are determined by the Board based on empirical analysis. It is essential that sufficient empirical analysis be provided periodically to ensure that assumed relationships are not misspecified. This includes the construction and application of a framework to evaluate the degree of comparability between rate regulated natural gas distribution and electricity distribution and transmission utilities in Canada and the United States.

To be clear, the approach to be used by the Board in setting the essential elements of a formula-based rate of ROE (i.e., base ROE, formula terms and adjustment factors) will be based on "economic theory and empirically derived from objective, data-based analysis."[26] As such, it is not sufficient for a formulaic approach for determining ROE to produce a

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[25] Ibid. p. 7.
[26] Ontario Energy Board. Report of the Board on 3rd Generation Incentive Regulation. July 14, 2008. p. 19

numerical result that satisfies the FRS on average, over time. The Board is of the view that each time a formulaic approach is used to calculate an allowed ROE it must generate a result that meets the FRS, as determined by the Board using its experience and informed judgment.

This principle is supported by the *Hope* decision, which states: "Under the statutory standard of 'just and reasonable' it is the result reached not the method which is controlling..."[27]

[27] Federal Power Commission v. Hope Natural Gas 320 U.S. 591 (1944). p. 602

# 4 The Board's Approach

## 4.1 Summary of Key Principles

As discussed previously, the Board confirms the following key principles with respect to its cost of capital policy. The Board has analyzed submissions, discussions at the consultation and the final written comments of participants to the consultation with these general principles in mind.

1. **Fair Return Standard.** All three requirements – comparable investment, financial integrity and capital attraction – must be met and none ranks in priority to the others. It is not sufficient for a formulaic approach for determining ROE to produce a numerical result that satisfies the FRS on average, over time. The Board is of the view that each time a formulaic approach is used to calculate an allowed ROE; it must generate a number that meets the FRS, as determined by the Board using its experience and informed judgment.

2. **The overall ROE must be determined solely on the basis of a company's cost of equity capital**. It does not mean that in determining the cost of capital that investor and consumer interests are balanced. The opportunity cost of capital should be determined by the Board based on a systematic and empirical approach that applies to all rate-regulated utilities regardless of ownership. The Federal Court of Appeal was clear that the overall ROE must be determined solely on the basis of a company's cost of equity capital and that the impact of any resulting toll increase is an irrelevant consideration in that determination.

3. **Efficient amount of investment.** As it relates to a rate regulated entity's cost of capital, the role of the regulator is to determine, as accurately as possible, the opportunity cost of capital to ensure that an efficient amount of investment occurs in the public interest for the purpose of setting utility rates.

4. **Predictability, transparency, and stability**. The approach adopted by the Board to determine the opportunity cost of capital should result in an environment where outcomes are predictable and consistent so that investors, utilities and consumers are better able to plan and make decisions.

5. **Systematic and empirically-based approach**. The methodology used by the Board to determine the cost of debt and equity capital should be a systematic approach that relies on economic theory and is empirically derived from objective, data-based analysis. For example, in establishing comparability, it is possible to build a low-risk sub-set from a higher risk universe using an empirically based approach.

6. **Minimize the time and cost of administering the framework.** Costs imposed on all participants, including the regulated entity and the regulator, should not exceed the benefits available. This objective could be met through a simple process that reflects the concerns of interested participants and reduces the formal process requirements.

## 4.2 Return on Equity

### 4.2.1 Need to Reset and Refine Existing ROE Formula

In order to ensure that on an ongoing basis changing economic and financial conditions are adequately and appropriately accommodated in the Board's formulaic approach for determining a utility's equity cost of capital, **the Board has determined that its current formula-based ROE approach needs to be reset and refined**. As previously indicated, **the Board will continue to use a formula-based ERP approach**. However, informed by the discussion at the consultation and the written comments of participants generated by the consultation, as well as its own analysis, the Board has concluded that the formula needs to be reset to address the difference between the allowed ROE arising from the application of the formula and the ROE for a low-risk proxy group that cannot be reconciled based on differences in risk alone. The formula also needs to be refined to reduce its sensitivity to changes in government bond yields due to monetary and fiscal conditions that do not reflect changes in the utility cost of equity.

The Board's current approach to estimating the cost of equity has been in effect for 12 years. The Board notes that in the 1997 Draft Guidelines, the Board stated that "it is persuaded that there exists a non-linear relationship between interest rates and the ERP." [28] The existing formula approximates this relationship using a linear specification. The Board is of the view that it is unreasonable to conclude that the current formula correctly specifies this relationship, based on the passage of time, changes in financial and economic circumstances generally, and the empirical analyses provided by participants to the consultation and the discussion at the consultation itself. However, the Board is of the view that its current formulaic approach for determining the equity cost of capital should be reset and refined, not otherwise abandoned or subject to wholesale change.

The events that unfolded earlier this year that triggered this review effectively illustrated that the Board's approach needs to be refined to reduce the sensitivity of the formula to changes in government bond yields due to monetary and fiscal conditions that do not reflect changes in the utility cost of equity. The Board concludes that the current approach could be more robust and better guide the Board's discretion in applying the FRS. The Board notes that while the current formula today produces results similar to that in 2008, it does not address the observed behaviour of the formula during the financial crisis – lowering the allowed ROE when the amount and price of risk in the market was increasing.

The view expressed by some participants in the consultation that the Board must wait to be provided with evidence from a regulated utility in Ontario of financial hardship due to the current allowed ROE before its adapts its policies to better reflect market realities is not consistent with the Board's approach.

The Board is of the view that resetting and refining the current formula-based ERP approach maintains the transparency, predictability and stability associated with the current

[28] Ontario Energy Board. Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities. March 1997. p. 31.

approach, and avoids sudden changes in regulatory policy to address potentially transitory capital market conditions. [29]

The Board has been informed by the numerous approaches used by various participants to the consultation to determine whether the formula continues to produce results that meet the FRS. The sum of the elements supporting the Board's decision to reset and refine its formulaic ROE is independent of the recent financial crisis and whether or not the crisis has abated.

### 4.2.2 The Initial Set Up

***Use of Multiple Tests***

The Board's current formulaic approach for determining ROE is a modified Capital Asset Pricing Model methodology, and in his written comments, Dr. Booth recommended that this practice be continued. Dr. Booth recommended that "the Board base its fair ROE on a risk based opportunity cost model, with overwhelming weight placed on a CAPM estimate"[30].

This view was not shared by other participants in the consultation, who asserted that the Board should use a wide variety of empirical tests to determine the initial cost of equity, deriving the initial ERP directly by examining the relationship between bond yields and equity returns, and indirectly by backing out the implied ERP by deducting forward-looking bond yields from ROE estimates.

Participants argued from a number of different perspectives that a variety of methods should be used to develop the ERP:

- "The Board should not limit itself to one specific method of calculating an ERP; rather it should consider the results produced by multiple approaches in order to

[29] Written Comments of the Industrial Gas Users Association, October 30, 2009, p. 2.
[30] Ibid. p. 20.

generate a range of reasonable results from which it may select an appropriate ERP. This process requires the exercise of informed judgment"[31].

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

  Multiple approaches for determining ROE provide greater assurance that the end result will be just and reasonable, as conditions that may bias results could be detected or mitigated by considering alternative results."[32]

- "The Board should consider comparable utilities' rates of return and a minimum spread to long-term debt rates, as well as resetting the reference rate".[33]

- "The Board should establish the initial ROE by looking at the best available evidence on the utilities' required return. This evidence should include results of various cost of capital methodologies...The Board would be remiss to predetermine a single methodology for establishing the initial allowed ROE without reviewing alternative methods for determining cost of equity."[34]

- "We propose that the Board, in reviewing cost of capital, would hear the evidence of the various experts with their different views of the ERP result, but would also look at

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[31] Concentric Energy Advisors. Written Comments on behalf of Enbridge Gas Distribution, Hydro One, and the Coalition of Large Distributors, September 8, 2009. September 8, 2009. p. 59.
[32] Ibid. p. 47.
[33] Written Comments of the Power Workers' Union. September 8, 2009. p. 6.
[34] Dr. J. H. Vander Weide. Written Comments on behalf of Union Gas. pp. 7-8.

other ways in which the market directly speaks about returns…they (the examples provided) and many other examples – are ways in which the market communicates the returns for investment comparable to utility investments. These sources are therefore useful in testing whether the results of various ERP or other market studies of cost of capital are realistic." [35]

- "If the utility is not a stand-alone entity and/or does not have traded shares, then the Board has no alternative but to look at total rates of return earned by investors in a relevant sample of companies." [36]

- "Expressing the ROE in terms of a premium above…long-term Canada bond yield… does not mean that the initial ROE need be estimated solely using a test or tests that might be defined as ERP tests." [37]

  "No single model is powerful enough to produce 'the number' that will meet the fair return standard. Only by applying a range of tests along with informed judgment can adherence to the fair return standard be ensured." [38]

- "…use of multiple tests. The tests all measure different factors that should be considered in setting a fair return on equity that is consistent with the comparable investment standard, the financial integrity standard and the capital attraction standard. The OEB should not rely on a single method or test." [39]

The Board agrees that **the use of multiple tests to directly and indirectly estimate the ERP is a superior approach to informing its judgment than reliance on a single methodology.** In particular, the Board is concerned that CAPM, as applied by Dr. Booth, does not adequately capture the inverse relationship between the ERP and the long

[35] Written Comments of the School Energy Coalition. September 2009. pp. 2-3.
[36] Written Comments of Energy Probe Research Foundation. September 8, 2009. p. 14.
[37] McShane, K., Foster Associates, Inc. Written Comments on behalf of the Electricity Distributors Association. September 8, 2009. p. 2.
[38] Ibid. p. 23.
[39] Written Comments of Ontario Power Generation Inc. September 8, 2009. p. 3.

Canada bond yield. As such, the Board does not accept the recommendation that it place overwhelming weight on a CAPM estimate in the determination of the initial ERP.

### *Setting the Initial Equity Risk Premium*

The Board is of the view that the initial ERP should be reset to address the difference between the allowed ROE arising from the application of the formula and the ROE for a low risk proxy group that cannot be reconciled based on differences in risk alone.

Therefore, based on the ERP recommendations provided by all participants in this consultation the **Board has determined that an initial ERP of 550 basis points** is appropriate for the purposes of deriving the initial ROE to be embedded in the Board's reset and refined ROE formula. This includes an implicit 50 basis points for transactional costs.

Consequently, **assuming a forecast long term government of Canada bond yield of 4.25%, the initial ROE to be embedded in the Board's reset and refined ROE formula will be 9.75%** (i.e., 4.25% + 550 basis points = 9.75%).

The Board has assessed the various empirical tests and recommendations submitted by participants and translated each of the recommended approaches as an ERP assuming a forecast long term government of Canada bond yield of 4.25%, where appropriate, as summarized in Table 1.

The empirical tests of each of the participants to the consultation are also described below. Although the Board maintains its view that each of the tests has empirical strengths and weaknesses, the diversity of approaches tabled and discussed in the consultation was helpful. As a result, the Board has given each test weight in the process to establish the initial ERP to be embedded in the Board's formula.

**Table 1: Summary of Participant Recommendations**

| Direct/Indirect Equity Risk Premium | Low | Medium | High |
|---|---|---|---|
| **Dr. L.D. Booth** | | | |
| CAPM (Adjusted Using CoC Formula to Reflect 4.25% GOC, 0.75 Adj) | 3.31% | 3.31% | 3.31% |
| **Average Dr. L.D. Booth** | **3.31%** | **3.31%** | **3.31%** |
| **Concentric Energy Advisors** | | | |
| DCF Analysis for Low-Risk Proxy Group (US Gas, Elec, Cdn) | 6.03% | 6.78% | 7.83% |
| CAPM Analysis for Low-Risk Proxy Groups (US Gas, US Elec, Cdn) | 4.58% | 4.72% | 4.86% |
| ERP Econometric Model (Average Gas and Electric) | 6.35% | 6.35% | 6.35% |
| **Average Concentric Energy Advisors** | **5.65%** | **5.95%** | **6.35%** |
| **J. Dalton - Power Advisory LLC** | | | |
| ERP Econometric Model #1 and ERP Econometric Model #2 | 6.05% | 6.45% | 6.85% |
| **Average J. Dalton - Power Advisory** | **6.05%** | **6.45%** | **6.85%** |
| **K. McShane - Foster Associates** | | | |
| New Formula for Calculating Allowed ROE (NEB Initial Formula Metrics) | 6.38% | 6.38% | 6.38% |
| Illustrative method | 5.75% | 5.75% | 5.75% |
| **Average: K. McShane** | **6.07%** | **6.07%** | **6.07%** |
| **Dr. J.H. Vander Weide** | | | |
| Experienced Equity Risk Premium | 4.30% | 5.50% | 6.60% |
| 2008 Awarded ROEs Vs. Avg 2008 US LT T-Bills - Gas | 6.16% | 6.16% | 6.16% |
| 2006-8 Awarded ROEs Vs. Avg 2006-8 US LT T-Bills - Gas | 5.61% | 5.61% | 5.61% |
| 2008 Awarded ROEs Vs. Avg 2008 US LT T-Bills - Electric | 6.26% | 6.26% | 6.26% |
| 2006-8 Awarded ROEs Vs. Avg 2006-8 US LT T-Bills - Electric | 5.71% | 5.71% | 5.71% |
| Forecast $E(R_e)$ = DCF Expected Return - LT Treasury Yield | | | |
| Gas | 6.19% | 6.19% | 6.19% |
| Electric | 6.21% | 6.21% | 6.21% |
| Regression - Ex-ante ERP (Above) with YTM LT Treasury Yields | | | |
| Gas (Modified to use Canadian LT GOC bond) | 6.97% | 6.97% | 6.97% |
| Electric (Modified to use Canadian LT GOC bond) | 7.33% | 7.33% | 7.33% |
| DCF Analysis for Value Line Utility Companies | | | |
| Gas | 7.81% | 7.81% | 7.81% |
| Electric | 8.71% | 8.71% | 8.71% |
| **Average: Dr. J.H.Vander Weide** | **6.48%** | **6.59%** | **6.69%** |
| **Average ERP All Submissions** | **5.51%** | **5.67%** | **5.85%** |

**Analyses of Dr. J. H. Vander Weide**

Dr. Vander Weide performed a number of empirical analyses. The average experienced ERP on an investment in Canadian utility stocks from data on returns earned by investors in Canadian utility stocks compared to interest rates on long-term Canada bonds was approximately 5.50 percent, as set out below:

| Comparable Group | Period of Study | Average Stock Return | Average Bond Yield | Risk Premium |
|---|---|---|---|---|
| S&P/TSX Utilities | 1956 - 2008 | 11.84% | 7.54% | 4.3% |
| BMO CM Utilities Stock Data Set | 1983 - 2008 | 14.31% | 7.66% | 6.6% |
| **Average** | | | | **5.5%** |

Source: Written comments of Dr. J.H. Vander Weide. Page 14.

He also provided information on recent allowed ROEs for U.S. utilities which demonstrated implicit ERPs:

| | Natural Gas Distribution | | Electric Utilities | |
|---|---|---|---|---|
| | 2008 | 2006 - 2008 | 2008 | 2006 - 2008 |
| Average U.S. ROE Awarded (%) | 10.4 | 10.3 | 10.5 | 10.4 |
| Spread to OEB September 2009 Long Bond Estimate of 4.25% | 6.15 | 6.05 | 6.25 | 6.15 |
| Spread to Average Long-Term Canada Bond Yield in 2008 of 4.06% | 6.34 | NA | 6.44 | NA |
| Spread to Average Long-Term Canada Bond Yield in 2006 to 2008 of 4.21% | NA | 6.09 | NA | 6.19 |
| Spread to Average Long-Term U.S. Treasury Bill Yield in 2008 of 4.24% | 6.16 | NA | 6.26 | NA |
| Spread to Average Long-Term U.S. Treasury Bill Yield in 2006 to 2008 of 4.69% | NA | 5.61 | NA | 5.71 |

Sources: Government of Canada Bond Yields: Bank of Canada; U.S. Long-Term Treasury Bill Yields: U.S. Department of Treasury

Further, forecast expected required returns by investors were calculated by Dr. Vander Weide by deducting the long-term Treasury bond yield from the DCF expected return (Exhibit 5, Dr. Vander Weide) over the period September 1999 to February 2009. This calculation produced an average ERP of 621 basis points for electric utilities and an average expected ERP of 619 basis points for natural gas utilities (Exhibit 6, Dr. Vander Weide) over the period June 1998 to February 2009.

However, regressing the relationship between the *ex ante* risk premium and the yield to maturity on long-term U.S. Treasury bond produced an ERP equation of:

- ERP = 12.10 – 1.123 x $I_B$ for Electric Utilities. Assuming an estimated Canadian Long-Term Bond yield of 4.25%, the Ex-Ante expected ERP is 7.33% and an ROE of 11.58%; and

- ERP = 10.26 – 0.773 x $I_B$ for Natural Gas Distribution Utilities. Assuming an estimated Canadian Long-Term Bond yield of 4.25%, the Ex-Ante expected ERP is 6.97% and an ROE of 11.22%.

Finally, Dr. Vander Weide conducted a DCF Analysis for Value Line Natural Gas Companies that resulted in an estimated ROE of 11.5% (Exhibit 9, Dr. Vander Weide) or an ERP of approximately 7.81%, using the average February 2009 long-term composite Treasury bond yield of 3.69%. His DCF Analysis for Value Line Electric Companies (Exhibit 8, Dr. Vander Weide) resulted in an estimated ROE of 12.4% or an ERP of approximately 8.71%, assuming the same long-term composite Treasury bond yield.

**Analysis of Kathy McShane of Foster Associates Inc.**

Ms. McShane proposed a new formula for calculating the allowed ROE: $ROE_{New}$ = Initial ROE + 50% (Change in Forecast GOC Bond Yield) + 50% (Change in Corporate Bond Yield Spread), which reflects the analysis provided in her comments.

Ms. McShane also demonstrated that using her recommended approach for 2009, based on the NEB formula contained in RH-2-94 Decision, the ROE would have been 10.73%[40], equal to an ERP of 638 basis points and assuming a forecast GOC yield of 4.35% for 2009.

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[40] McShane, K., Foster Associates Inc. Written Comments on behalf of the Electricity Distributors Association. Schedule 4.

For illustrative purposes in her analysis, she linked a forecast long-term Canada bond yield of 4.5% and a corporate bond yield spread of 175 basis points to an ROE of 10%. Implied in this ROE is an ERP of 550 basis points.

**Analysis of Power Advisory LLC**

Power Advisory evaluated a range of different model specifications in an effort to come up with a formula that will yield more reasonable results than the existing formula under a range of different credit and financial market conditions.[41] Two models performed the best in terms of standard econometric considerations (i.e., goodness of fit, highly significant parameter values, and plausible statistical relationships)[42]:

1. ROE = 7.008% + (US Corp BAA Bond Yield with 6 month lag x 0.5356); and
2. ROE = 7.451% + (US Gov 30 Year Bond yield with 6 month lag x 0.5122) + (VIX index value with 6 month lag x 0.0077).

Using current values for these variables produces ROE estimates of 10.5% to 11.3%. Using Canadian values in these models results in ROE estimates of 10.3% to 11.1%. The implied ERP using the results of the models run using a forecast long-term government of Canada bond yield of 4.25% is 605 basis points to 685 basis points.

**Analysis of Concentric Energy Advisors**

Concentric's overall recommended ROE for natural gas distribution utilities, assuming a 40% deemed equity capital structure is 10.5% and for electric transmission and distribution utilities is 10.3%, also assuming 40% deemed equity. The implied ERP assuming a 4.25% forecast GOC bond yield is 625 basis points and 605 basis points, for natural gas and electric transmission and distribution, respectively. These recommendations are supported by multiple analytical approaches; each calculated using data for a specific proxy group for

[41] Power Advisory LLC. Written Comments on behalf of Great Lakes Power Transmission LP. September 8, 2009. p. 16.
[42] Ibid. p. 17.

the natural gas and electric transmission and distribution utilities established by Concentric.[43]

The results of Concentric's DCF analysis are presented in the table below[44].

| Proxy Group | Low | Mean | High |
|---|---|---|---|
| U.S. Natural Gas Distribution Utilities | 9.70% | 10.44% | 11.57% |
| U.S. Electric Distribution Utilities | 10.08% | 10.96% | 12.09% |
| Canadian Utilities | 9.97% | 10.60% | 11.47% |
| Average | 9.92% | 10.67% | 11.71% |
| Implied ERP at 4.25% forecast LT GOC Yield | 5.67% | 6.42% | 7.46% |
| Implied ERP Including 50 basis points Flotation Costs | **6.17%** | **6.92%** | **7.96%** |

The results of Concentric's CAPM analysis are presented in the table below. The results reflect a Market Risk Premium of 586 basis points, which is supported by material provided in Appendix F (page F-10) and Exhibit Concentric-06 of their written comments.

| Proxy Group | Low | Mean | High |
|---|---|---|---|
| U.S. Natural Gas Distribution Utilities | 9.05% | 9.18% | 9.32% |
| U.S. Electric Distribution Utilities | 8.54% | 8.68% | 8.82% |
| Canadian Utilities | 7.80% | 7.95% | 8.10% |
| Average | 8.46% | 8.61% | 8.75% |
| Implied ERP at 4.25% forecast LT GOC Yield | 4.21% | 4.36% | 4.50% |
| Implied ERP Including 50 basis points Flotation Costs | **4.71%** | **4.86%** | **5.00%** |

The results of Concentric's ERP analysis are presented in the table below and are explained in detail in Appendix F of their written comments.

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[43] Concentric Energy Advisors. Written Comments on behalf of Enbridge Gas Distribution, Hydro One, and the Coalition of Large Distributors. September 8, 2009. Appendix C.
[44] Ibid. p. F-6.

Concentric's ERP regression formula is as follows: ROE = Constant = U.S. Gov 30-year Bond • $x_1$ + Moody's Utility A-rated Spread • $x_2$ + % Generation • $x_3$ + Natural Gas Dummy Variable • $x_4$.[45]

| | **U.S. Natural Gas Distribution Proxy Group** | **U.S. Electric Distribution Proxy Group** |
|---|---|---|
| Constant | 7.634 | 7.634 |
| U.S. Government 30-year Bond Yield | 0.428 x 4.18 | 0.428 x 4.18 |
| Moody's Utility A-rate Spread (July 2009) | 0.310 x 1.56 | 0.310 x 1.56 |
| % Generation | 0.008 x 0.00 | 0.008 x 49.76 |
| Natural Gas Dummy (Electric = 0,Gas = 1) | 0.384 x 1.00 | 0.384 x 0.00 |
| Authorized ROE | 10.29% | 10.30% |
| Implied ERP at 4.25% forecast LT GOC Yield | 6.04% | 6.05% |
| Implied ERP Including 50 basis points Flotation Costs | **6.54%** | **6.55%** |

The tables below summarize Concentric's recommended ROEs prior to any adjustment for changes in leverage:[46]

| U.S. Electric T & D Utilities | **Low** | **Mean** | **High** |
|---|---|---|---|
| DCF | 10.08% | 10.96% | 12.09% |
| CAPM | 8.54% | 8.68% | 8.82% |
| Average | 9.31% | 9.82% | 10.46% |
| Differential between Vertically Integrated and T&D Utilities | (0.40%) | (0.40%) | (0.40%) |
| Return before Leverage and Flotation Cost Adjustments | 8.91% | 9.43% | 10.06% |
| Flotation Cost Adjustment 0.50% | 0.50% | 0.50% | 0.50% |
| Benchmark T&D ROE | 9.41% | 9.93% | 10.56% |
| Benchmark T&D Equity Ratio | 46.32% | 46.32% | 46.32% |
| Implied ERP using 4.25% forecast LT GOC Yield | 5.16% | 5.68% | 6.31% |

| U.S. Natural Gas Distribution Utilities | **Low** | **Mean** | **High** |
|---|---|---|---|
| DCF | 9.70% | 10.44% | 11.57% |
| CAPM | 9.05% | 9.18% | 9.32% |
| Return before Leverage and Flotation Cost Adjustments | 9.37% | 9.81% | 10.45% |
| Flotation Cost Adjustment 0.50% | 0.50% | 0.50% | 0.50% |
| Benchmark Natural Gas Distribution ROE | 9.87% | 10.31% | 10.95% |
| Benchmark Natural Gas Distribution Equity Ratio | 44.47% | 44.47% | 44.47% |
| Implied ERP using 4.25% forecast LT GOC Yield | 5.62% | 6.06% | 6.70% |

Adjusting for leverage that is higher than the benchmark equity ratio, i.e., deemed equity of 40%, the recommended ROEs increase to 10.5% for natural gas distribution and 10.3% for electric transmission and distribution, representing implied ERPs of 625 basis points and 605 basis points, respectively.

[45] Ibid. p. F-14.
[46] Ibid. p. F-16.

## Analysis of Dr. Booth

Dr. Booth recommended a fair ROE of 7.75%. This number is based on the following key assumptions.[47]

First, a market risk premium of 5.0%. However, Dr. Booth noted that many of his peers believe it to be 6.0%. Second, beta is estimated to be 0.5. Dr. Booth indicated that he "is not using the current beta coefficient"[48]; i.e., the beta of 0.5 used to derive the recommended ERP of 325 (assuming a 4.50% long-term government of Canada bond yield) is not supported by Dr. Booth's recent beta estimates, where beta is less than 0.5. Thirdly, Dr. Booth also noted that the range of fair return cost of equity estimates could vary by 0.50%. His unadjusted estimate of a fair return was 7.00% and he noted that the estimates of his colleagues would be 7.50%. He therefore added 0.25% to his estimate to "split this difference", resulting in his ROE recommendation of 7.25%. Finally, Dr. Booth added 0.50% for issuance costs, bringing his fair recommended return to 7.75%.

The Board notes that in the course of the consultation, Dr. Booth indicated that he would be prepared to recommend "fixing ROE at 8.5% or 8.75% over the business cycle, for say, a five-year period."[49] Dr. Booth did not support this estimated ROE with empirical analysis, and as such, there is no principled basis upon which the Board can rely on Dr. Booth's recommendation of 8.5% or 8.75%.

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[47] Professor L.D. Booth. Written Comments on behalf of Consumers Council of Canada, the Vulnerable Energy Consumer's Coalition, the Industrial Gas Users Association, the Canadian Manufacturers & Exporters, the London Property Management Association and the Building Managers and Owners Association of the Greater Toronto Area. September 8, 2009. p. 40.

[48] Ontario Energy Board. Transcript of Consultation Process on Cost of Capital Review. October 6, 2009. p. 100. Lines 12 and 13.

[49] Ontario Energy Board. Transcript of Consultation Process on Cost of Capital Review. October 6, 2009. p. 98. Lines 10 – 12.

### 4.2.3 The Formula-based Return on Equity

#### 4.2.3.1 Long Canada Bond Forecast

**The Board is of the view that the LCBF continues to be an appropriate base upon which to begin the ROE calculation**. In particular, the Board is of the view that the sensitivity of the allowed ROE to changes in government of Canada bond yields arising from monetary and fiscal conditions that do not reflect changes in utility cost of equity will be addressed, in part, by the use of multiple methods to determine the initial ERP or ROE in the formula. The Board also agrees with Ms. McShane's comment that the LCBF provides an important forecast component to the formula[50] and with the Industrial Gas Users Association's comment that "there is an intrinsic logic to using the same parameter to adjust ROE as was used to set the ROE in the first place."[51]

#### 4.2.3.2 Long Canada Bond Forecast Adjustment Factor

In its 1997 Draft Guidelines, the Board determined that the difference between the LCBF for the current test year and the corresponding rate for the immediately preceding year should be multiplied by a factor of 0.75 to determine the adjustment to the allowed ROE.[52] In that same document, however, the Board noted that there was a significant difference of opinion concerning the relationship between interest rates and the ERP and that ratios contained in the evidence from generic rate of return proceedings in other Canadian jurisdictions ranged from 0.5:1 to 1:1.[53] Moreover, the Board notes that the selection of the 0.75 adjustment factor is described in the 1997 Draft Guidelines as "admittedly somewhat arbitrary."[54]

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[50] Ontario Energy Board. Transcript of Consultation Process on Cost of Capital Review. September 22, 2009. Ms. McShane's presentation, pp. 161-162;
[51] Final Written Comments of the Industrial Gas Users Association. October 30, 2009. p. 10.
[52] Ontario Energy Board. Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities, March 1997. p. 31.
[53] Ibid.
[54] Ibid. p. 32.

The Board views **the determination of the LCBF adjustment factor to be an empirical exercise, and as such, based on the empirical analysis provided by participants in conjunction with the consultation, the Board is of the view that the LCBF adjustment factor should be set at 0.5**. The Board notes that four participants in this consultation empirically tested the relationship between government bond yields and ROE:

- Dr. Vander Weide determined that when the yield to maturity on long-term government bonds increases by 100 basis points, the allowed ERP tends to decrease by approximately 55 basis points, and when the yield to maturity on long-term government bonds decreases by 100 basis points, the allowed ERP tends to increase by approximately 55 basis points.[55]

- Kathy McShane of Foster Associates, Inc. submitted that a regression analysis used to estimate the relationship between government bond yields and the utility cost of equity indicates that the ROEs increased (decreased) by approximately 50 basis points for every one percentage point increase (decrease) in long-term government bond yields.[56]

- Concentric Energy Advisors also conducted a regression analysis in which the litigated ROEs of U.S. LDC utility returns demonstrated an elasticity factor to government bond yields of 0.45. This implies that the risk premium should have actually increased by approximately 0.55 for each percentage point drop in the government bond yield (as opposed to the 0.25 implied by the current formula).[57]

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[55] Dr. J.H. Vander Weide. Written Comments on behalf of Union Gas. September 8, 2009. p. 21.
[56] K. McShane. Foster Associates, Inc. Written Comments on behalf of the Electricity Distributors Association. September 8, 2009. p. 26.
[57] Concentric Energy Advisors. Written Comments on behalf of Enbridge Gas Distribution, Hydro One, and the Coalition of Large Distributors. September 8, 2009. pp. 41-42.

- John Dalton of Power Advisory also used a regression analysis to determine that the ERP changes by less than 50% of the change in the long-term government bond rate.[58]

The Industrial Gas Users Association also stated that it sees some merit in further consideration of adjusting downwards to 0.5 the coefficient for application of changes in long Canada bond yields to ROE.

#### 4.2.3.3 Additional Term – Changes in Utility Bond Spread

The Board is of the view that the sensitivity of the formula to changes in government bond yields due to monetary and fiscal conditions that do not reflect changes in the utility cost of equity is addressed, in part, by using multiple methods to determine the initial ERP and ROE in its formulaic ROE approach and by reducing the LCBF adjustment factor to 0.5 from 0.75. The Board also is of the view, however, that **the specification of the relationship between interest rates and the ERP in the formula would be improved by the addition of a further term to the formula**.

In particular, the Board is of the view that there is a relationship between corporate bond yields and the equity return, and the Board agrees with Dr. Booth, who stated, with respect to corporate bond spreads, that "this is not to say that spreads have no information about required risk premium."[59] The Board notes that three participants to the consultation conducted empirical analysis to specify the relationship between corporate bond yields and the equity return:

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[58] Power Advisory LLC. Written Comments on behalf of Great Lakes Power Transmission LP. April 17, 2009. p. 15.
[59] Professor L.D. Booth. Written Comments on behalf of Consumers Council of Canada, the Vulnerable Energy Consumer's Coalition, the Industrial Gas Users Association, the Canadian Manufacturers & Exporters (CME), the London Property Management Association and the Building Managers and Owners Association of the Greater Toronto Area. September 8, 2009. p. 29.

- Concentric demonstrated by using a regression analysis that there is a statistically significant relationship between ROE and corporate bond yields and specified that the sensitivity of allowed returns to corporate bond yields is about 0.45 to 0.55[60]. Concentric also demonstrated empirically that Treasury bonds have been more volatile than corporate bonds since January 1997.

- Kathy McShane of Foster Associates tested the relationship between corporate bond yields and the utility cost of equity. She determined the cost of equity using two approaches: first, by using approved returns on equity for utilities not governed by formulas as a proxy for the utility cost of equity, and second, by relying on a time series of utility costs of equity developed by using the discounted cash flow approach against which yields on utility bonds can be compared[61]. By using regression analysis, Ms. McShane determined that allowed ROEs have increased (decreased) by approximately 45 basis points for every one percentage point increase (decrease) in the A rated utility bond yield. Similarly, the DCF cost of equity increased (decreased) by approximately 55 basis points for every one percentage point increase (decrease) in long-term A rated utility bond yields.[62]

- John Dalton from Power Advisory LLC conducted an econometric analysis, which established that the relationship between ROE and U.S. corporate BAA bond yields with a six month lag is approximately 0.53.[63]

Based on the analysis provided by participants to the consultation, the Board concludes that **there is a statistically significant relationship between corporate bond yields and the cost of equity, and that a corporate bond yield variable should be incorporated in the ROE formula**. The Board notes that the presence of a corporate bond yield variable in its

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[60] Concentric Energy Advisors. Written Comments on behalf of Enbridge Gas Distribution, Hydro One, and the Coalition of Large Distributors. September 8, 2009. pp. 53–55.
[61] K. McShane. Foster Associates, Inc. Written Comments on behalf of the Electricity Distributors Association. September 8, 2009. p. 25.
[62] Ibid. p. 26.
[63] Power Advisory LLC. Written Comments on behalf of Great Lakes Power Transmission LP. September 8, 2009. p. 17.

current ROE formula would have served to increase the allowed ROE during the recent credit crisis, which, in the Board's view, would have been directionally correct.[64]

The Board has determined that it is appropriate to use a corporate yield variable that is reflective of the borrowing costs of Canadian utilities, one that is well-understood and is based on an established index from a recognized source. **The Board has** accordingly **determined that it will use a utility bond spread based on the difference between the Bloomberg Fair Value Canada 30-Year A-rated Utility Bond index yield and the long Canada bond yield.** This is further described in Appendix B.

The Board agrees with the comment of Ms. McShane that separating the LCBF and the utility bond spread variables, as opposed to using one corporate bond yield variable that would implicitly incorporate the LCBF, provides transparency as it shows "what part is causing the ROE to move in either direction."[65]

**The Board also determines that the utility bond spread reflected in the reset and refined formulaic ROE approach will be subject to a 0.50 adjustment factor**, consistent with the empirical analyses provided by participants to the consultation.

## 4.3 Capital structure

**The Board's current policy with regard to capital structure for all regulated utilities continues to be appropriate**. As noted in the Board's draft guidelines, capital structure should be reviewed only when there is a significant change in financial, business or corporate fundamentals.[66] The Board's current policy is as follows:

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[64] Written Comments of the Electricity Distributors Association. September 8, 2009. Schedule 4.
[65] Ontario Energy Board. Transcript of Consultation Process on Cost of Capital Review. Ms. McShane's presentation, p. 161.
[66] Ontario Energy Board. Ontario Energy Board Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities. March 1997. p. 2

BRITISH COLUMBIA UTILITIES COMMISSION

**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**

**BEFORE:**

**Anthony J. Pullman, Commissioner/Panel Chair**
**D.A. Cote, Commissioner**
**M.R. Harle, Commissioner**

responsibility is to regulate rates as a surrogate for competition and to keep rates within the reasonableness one would expect in a properly functioning market. Considering the customer perspective is one-half of the balance equation in a regulated environment. When acting as the surrogate for competition, the Commission cannot and must not protect Terasen from all competitive risk by raising the ROE at the expense of customers. Doing so would ignore the interest of the customers who are captive to the monopoly. (ICG Argument, p. 5)

Terasen submits that the following quotation from page eight of the Commission's 2006 Decision on Terasen's ROE, Capital Structure and the AAM ("2006 ROE Decision") correctly sets out that 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 does not accept that the reference by Martland J. to a "balancing of interests" to mean that the exercise of determining a fair return is an exercise of balancing the customers' interests in low rates, assuming no detrimental effects on the quality of service, with the shareholders' interest in a fair return. 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." (Terasen Reply, para 6)

### 2.2 The Fair Return Standard

Terasen cites the TQM Decision, which summarizes the fair return standard at page 6:

> "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)." (Terasen Argument, para 12)

Terasen and the Intervenors address the fair return standard from the perspectives of the return on invested capital of the utility, the return on the equity, the level of financial risk, the creditworthiness and financial integrity of the utility, and, on the premium paid over book value for TI by Fortis Inc. in 2007.

In her evidence, Ms. McShane states: "The capital structure and the return on equity are inextricably linked; the fair return on equity cannot be established without reference to the level of financial risk inherent in the capital structure adopted for regulatory purposes." (Exhibit B-1, Tab 3, p. 3)

Ms. McShane addresses the maintenance of the creditworthiness and financial integrity of the utility and opines that the capital structure of TGI, in conjunction with the returns allowed on its sources of capital, should provide the basis for a stand-alone investment grade debt ratings in the A category. Debt ratings in the A category assure that Terasen should be able to access the capital markets on reasonable terms and conditions during both robust and difficult, or weak, capital market conditions. (Exhibit B-1, Tab 3, p.26; Terasen Argument, para 101)

The Intervenors do not disagree with the A rating but observe that Terasen has enjoyed an A rating for many years. (JIESC Argument, p. 12)

JIESC points out that:

- in 2007, Fortis Inc. "purchased the TGI equity (sic) paying a premium of $900 million for it. A premium over book value upon which Terasen is not permitted to allow either a debt or equity return. This amounts to 1.7 times the equity value";
- in February 2009, a time when "debt markets were still recovering from the 2008 financial turmoil" TGI was able to issue $100 million debt; and

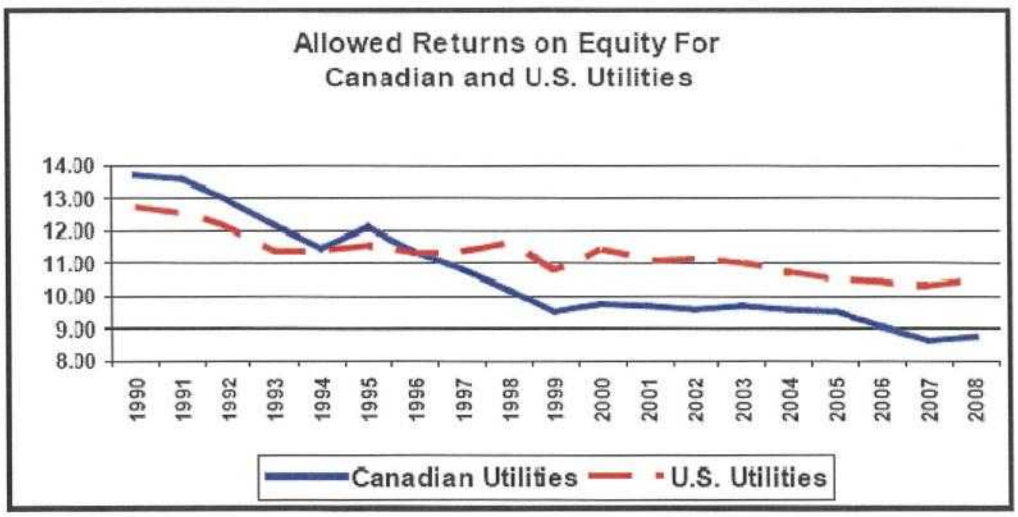
- in May 2009 TGI's bond rating was confirmed at "A" by both DBRS Limited ("DBRS") and Moody's Investors Services ("Moody's"). (JIESC Argument, p. 13)

Terasen points out that TGI's Moody's rating actually is A3 and submits that the rating is "only one notch above BBB+, which is a level at which even Dr. Booth believes TGI should not be." (Terasen Reply, para 82)

Terasen also addresses the issue of acquisition premia and refers the Commission to its 2006 ROE Decision where the Commission addressed the acquisition of TI by Kinder Morgan Inc. ("KMI") and stated at page 13: "There is no evidence before the Commission that any of the premium paid by KMI will be included in either of the Companies' rate bases and recovered from their customers. The Commission's role is to determine a suitable capital structure for the Applicants and return on equity for a benchmark low-risk utility and the KMI/TI transaction is not relevant to the Commission's determination." (Terasen Reply, para 94)

### 2.3 The Applicability of US Data in Determining the Fair Return Standard

Terasen provides the following chart to compare the differences between ROEs allowed to electric and natural gas utilities by state regulatory agencies in the US with the ROEs allowed by Canadian regulatory agencies:




(Exhibit B-1, p. 14)

Terasen includes two reports as appendices to the Application:

i) a report sponsored by the Ontario Energy Board ("OEB") entitled "A Comparative Analysis of Return on Equity of Natural Gas Utilities" dated June 14, 2007 and authored by Concentric Energy Advisors ("CEA") (the "CEA Report"); and

ii) a report sponsored by the Canadian Gas Association ("CGA") entitled "Allowed Return on Equity in Canada and the United States: An Economic, Financial and Institutional Analysis" authored by National Economic Research Associates, Inc ("NERA") dated February 2008 (the "NERA Report").

The CEA Report made ten conclusions, of which three are germane:

1. "(6) On the whole, there are no evident fundamental differences in the business and operating risks facing Ontario utilities as compared to those facing US companies or other provinces' utilities that would explain the difference in ROEs";
2. "(7) Other market related distinctions and resulting financial risk differences, particularly between Canada and the US, do exist. These factors, including differences in market structure, investor bases, regulatory environments, and other economic factors may have an impact on investors' return requirements for Canadian versus US utility investments. However, through analysis and interviews with key market participants, representatives of customer groups, and other individuals with past involvement in ROE proceedings in Canada and the US, these differences are determined to be negligible"; and
3. "(9) As a result of the interplay between the Canadian and US markets, Canadian utilities compete for capital essentially on the same basis as utilities in the US." (Exhibit B-1, Appendix 3)

The NERA Report concludes, in part:

"We find that the regulatory institutions and customs for setting regulated prices for investor owned Canadian and US utilities are very alike. That is, in accounting, administrative procedures, regulatory legislation, and basic constitutional protections of private property, little or nothing separates the average Canadian from the average US regulatory jurisdictions..."

"We examine the definition of risk to investors of placing their capital at the use of the public, for which the ROE provides compensatory payment. We look at how those risks could be different in Canada versus the US. What we find is that the basic sources of risk—regulatory, business and financial—are comparable with respect to both jurisdictions. Objective and disinterested analyses of the relative risks between Canadian and US utilities are rare, but what we have found points to no smaller risks in Canada. As such, we conclude that there is no objective evidence showing that business or regulatory risks are sufficiently lower in Canada to account for the divergences in Figure 1 [A Figure showing the Allowed Return Differential (Canada - US) for Gas Distribution Utilities in the period 1992-2007]." (Exhibit B-1, Appendix 4, Executive Summary)

Terasen filed the evidence of Mr. Donald A. Carmichael, a financial consultant and advisor, as Tab 2 to the Application. His opinion evidence addresses the integration of markets and competition for capital. Mr Carmichael states that the globalization of Canadian capital markets and the removal of various personal and institutional restrictions on foreign investment have caused the Canadian and international capital markets to become substantially more integrated than in the past, and points to the fact that:

- many of Canada's largest institutional investors have become major players on international stock markets and non-Canadian private equity situations;
- the market in Canada for the new issuance of foreign bonds and debentures has grown rapidly reflecting Canadian lenders' desire to diversify their portfolios with new issuers and to achieve higher returns than those available from domestic issuers; and
- the funding requirements for announced infrastructure projects in Canada will be significant and will directly compete with debt and equity financing for utilities. (Exhibit B-1, Tab 2, pp. 32-35)

Terasen submits that restrictions on foreign investments by Canadians have been removed and that competition for capital is not constrained by provincial or national borders. Canadian and international capital markets have become more integrated than in the past. Large amounts of capital are required for infrastructure projects in Canada and around the world. Terasen submits that TGI's capital structure and return on equity must be comparable to other companies of similar risk to allow it to successfully compete for capital. (Terasen Argument, para 19)

The NEB addressed the issue in the TQM Decision where it stated:

> "In the Board's view, global financial markets have evolved significantly since 1994. Canada has witnessed increased flows of capital and implemented tax policy changes that facilitate these flows. As a result, the Board is of the view that Canadian firms are increasingly competing for capital on a global basis.
>
> A fair return on capital should, among other things, be comparable to the return available from the application of the invested capital to other enterprises of like risk and permit incremental capital to be attracted to the regulated company on reasonable terms and conditions. TQM needs to compete for capital in the global market place. The Board has to ensure that TQM is allowed a return that enables TQM to do so. ...As a result, the Board is of the view that pipeline companies operating in the U.S. have the potential to act as a useful proxy for the investment opportunities available in the global market place." (TQM Decision, pp. 66-67)

In addition, the AUC stated that it would, "review the market based return data available on the record in respect of the sample US utility proxy groups and employ this data in its CAPM [Capital Asset Pricing Model] and DCF [Discounted Cash Flow] determinations." (AUC Decision 2009-216, para 205)

Terasen submits that global competition for capital means that TGI's capital structure must be comparable to its North American peers. In Terasen's view, the TQM Decision recognizes this capital requirement, which should also be recognized by the Commission. (Terasen Argument, para 95)

In the 2006 ROE Decision the Commission addressed what it saw as the two issues of relying on US data to establish appropriate capital structures and ROEs for utilities. On the first issue (i.e. that there are opportunities for Canadian investors to commit capital globally) the Commission noted that Canadian investors faced a considerable foreign exchange risk when investing and was not convinced that the Federal Government's relaxation of foreign content rules in retirement portfolios should be a reason to increase the equity return of a benchmark low-risk utility.

On the second issue (i.e. that in measuring the risk premium it is necessary to look beyond Canadian data) the Commission stated that it was prepared to accept the use of historical and forecast data of 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; based on the fact that the US and Canadian economy and capital markets were closely integrated. (2006 ROE Decision, p. 50)

BCOAPO submits that "select US utilities...are not useful in determining comparable returns and comparable risk." (BCOAPO Argument, para 7)

Dr. Laurence Booth provided a written opinion of the fair return for TGI on behalf of the Intervenors. In his evidence, Dr. Booth states: "The message from these....disasters of US regulatory policy [i.e. the bankruptcy of Pacific Gas and Electric; the Enron and WorldCom frauds; the failure of US entities such as Lehman Brothers; and 'stock market disasters represented by pipelines like Duke Energy'] is that the US is not Canada, no matter what American witnesses before the Canadian regulatory tribunals seem to think. Regulation in the US has followed a different path to that in Canada, as is patently obvious to anyone who looks at its results. Drawing any insights from how investors perceive US utilities (or banks) given this different regulatory approach in my judgment is of very little value. I would strongly advise Canadian regulatory tribunals to ignore the advice of experts, who have US experience in mind when they from (sic) their judgments. Instead, they should focus on Canadian solutions that have worked rather than US solutions that have resulted in disaster." (Exhibit C11-5, p. 103)

Terasen submits that the evidence demonstrates that Dr. Booth's attempt to use Enron and WorldCom as examples of light-handed US utility regulation fails; neither Enron nor WorldCom were US utilities or utility holding companies, and Dr. Booth's citation of Enron, WorldCom, or Duke Energy fails to support the argument that the Commission should not consider US utilities in its determination of a fair return on equity. (Terasen Argument, para 352-53)

**Commission Determination**

In view of the fact that no party took issue with the articulation of the fair return standard by the NEB in the TQM Decision, the Commission Panel endorses it. It also agrees with Terasen that the combination of the equity ratio and the allowed return thereon should be adequate to attract capital on reasonable terms and conditions and allow TGI to maintain the A3 rating on its debt and unsecured debt from Moody's.

As for the Intervenors' submissions that this is not the time for a rate increase, and ICG's submission that the Commission must balance the requirements of customers with those of Terasen, the Commission Panel adopts the Commission's statement in the 2006 ROE Decision where it made it clear that its obligation was and is to set rates that are fair and reasonable, and to allow a utility the opportunity to earn a fair rate of return.

The Commission Panel has considered the premium paid by Fortis Inc. to acquire the equity capital of TI in 2007. As was the case with respect to the premium paid by KMI for the shares of TI discussed in the 2006 ROE Decision there is no evidence before the Commission that any of the premium paid by Fortis Inc. will be included in any of the Companies' rate bases and recovered from their customers. Further, as was the case with the KMI acquisition, the Commission imposed "ring-fencing" conditions upon Fortis Inc. The Commission Panel considers that the Commission's role is to determine an appropriate capital structure and return on equity for Terasen and that the acquisition of TI by Fortis Inc. is not relevant to the Commission Panel's determination in this regard.

As for the US data, the Commission Panel agrees with the NEB and AUC that utilities in Canada need to compete for capital in the global market place, and regulatory agencies in Canada have to ensure that utilities subject to their jurisdiction are allowed a return that enables them to do so.

In addition, the Commission Panel continues to be prepared to accept the use of historical and forecast data of US utilities when applied: as a check to Canadian data, as a substitute for Canadian data when Canadian data do not exist in significant quantity or quality, or as a supplement to Canadian data when Canadian data gives unreliable results. Given the paucity of relevant Canadian data, the Commission Panel considers that natural gas distribution companies operating in the US have the potential to act as a useful proxy in determining TGI's capital structure, ROE, and credit metrics.

Having determined what the fair return comprises and that US data may be relevant in its determination, the Commission Panel considers that there are enough data before it to bring into question whether the fair return standard is being met in TGI's case. Accordingly, in the following sections the Commission Panel examines the evidence and determines whether an increase in TGI's equity ratio is justified, following which it determines the approaches to which it will give weight in its determination of TGI's allowed ROE. The Commission Panel examines the result of these determinations to ensure that the fair return standard is met for TGI.

## 3.0 RISKS AND CAPITAL STRUCTURE

This Section defines risk in the utility regulatory environment, considers TGI's business risk and determines a suitable capital structure for TGI for regulatory purposes. The following issues are addressed:

- Have the business, regulatory and financial risks of TGI increased since 2005 and, if so, how should they be reflected in TGI's capital structure?
- What is TGI's appropriate capital structure?

Terasen sets out the following reasons why TGI's common equity ratio should be increased from 35.01 percent to 40 percent:

1) TGI's level of business risk has increased;
2) there have been material increases in the allowed common equity ratios of some of TGI's Canadian utility peers;
3) its credit metrics are weak for its credit ratings, and in isolation fall below investment grade guidelines;
4) its equity ratio of 35 percent, together with lower allowed ROEs and lower corporate income tax rates have caused its interest coverage ratios to be the lowest in Canada and to continue to fall;
5) rating agencies continue to view a common equity ratio of 35.01 percent as weak. At 40 percent TGI would still lie at the lower end of Moody's guideline range for an investment grade rating on this credit metric;
6) the further global integration of the Canadian capital markets warrants a strengthening of TGI's financial parameters; and
7) the forecast North American and global investment requirements for infrastructure point to significant competition for capital going forward. TGI should be positioned so that it can compete successfully. At the existing capital structure, TGI's credit metrics compare unfavourably to those of its US peers. (Exhibit B-1, Tab 3, pp. 39-40)

The assessment of risks has significant bearing on the application of the fair return standard and the determination of an appropriate common equity ratio for regulatory purposes.

### 3.1 The Definition of Risk in the Utility Regulatory Environment

In discussing business risk in its Argument, Terasen refers to page 17 of the 2006 ROE Decision. At that reference, the Commission defined risk as follows:

> "The Applicant and Intervenors broadly agree on the definition of risk to a benchmark low-risk utility. Investment risk comprises the sum of business risk, financial risk and regulatory risk."
>
> "Business risk is the risk that the utility will not be able to earn a return on its capital or of its capital. Dr. Booth summarized those elements that constitute business risk as:
>
> > '...stemming from uncertainty in the demand for the firm's product resulting, for example, from changes in the economy, the actions of competitors, and the possibility of product obsolescence. This demand uncertainty is compounded by the method used by the firm and the uncertainty in the firms' cost structure, caused, for example, by uncertain input costs, like those for labour or critical raw or semi-manufactured materials.' "
>
> "Financial risk is measured through the debt equity ratio of a utility."
>
> "Regulatory risks are those that might arise from regulatory lag, from disallowed operating or capital costs or from punitive awards." (2006 ROE Decision, p. 17 [references omitted]; Terasen Argument, para 23)

Terasen discusses the business risk of TGI and states that it is useful to consider short-term and long-term risks. In the short-term the focus is generally on TGI's ability to earn a fair return on its investments from year to year. In the longer term the risk relates to whether or not the utility will be able to recover the cost of its investments over their useful lives and earn a fair return on such investment over the long run. (Exhibit B-3, BCUC 14.1)

Terasen notes that business risk has both short-term and long-term aspects and that since a local distribution company's ("LDC") investments have a useful life that extends over a long period of time, it is the longer-term fundamental business risks that must be given primary consideration when evaluating the business risk of a gas distribution utility.

Ms. McShane observes that regulatory agencies in Canada have followed two separate approaches to addressing utility risk. The NEB and the AUC have adopted one approach whereby each utility subject to their jurisdiction has an individual equity ratio which is determined by its respective long and short-term business risks, to which is applied a uniform ROE. The other approach, followed by the Commission, the OEB and the *Regie de l'Energie*, is to establish the capital structure and ROE for a benchmark utility and to set capital structures and ROEs for all other utilities in their jurisdiction with reference to the benchmark. (Exhibit B-1, Tab 3, p. 21)

**Commission Determination**

The Commission Panel notes that no party took issue with the Commission's characterization of risk in its 2006 ROE Decision and accordingly accepts the definition for the purposes of this proceeding.

The Commission Panel accepts Terasen's characterization of its business risk as having long-term and short-term aspects and it will consider them separately in Sections 3.2 and 3.3 of this Decision.

In its 2006 ROE Decision the Commission stated: "The Commission Panel concludes that the appropriate capital structure range for consideration of TGI is in the range of 35 percent to 38 percent and that given the effect of deferral accounts in reducing the risk of TGI, the appropriate equity component for TGI is 35 percent. Given the preferred shares in the capital structure of all other Canadian gas distribution utilities, the equity component of TGI will remain the lowest in Canada for gas distribution utilities." (2006 ROE Decision, p. 36)

In this Decision, however, the Commission Panel considers the effect of deferral accounts in reducing the risk of TGI as reducing the short-term, and not the long-term, business risk of TGI, and will accordingly adjust TGI's ROE rather than its capital structure.

Terasen also cites the Commission's discussion of TGI's Revenue Stabilization Adjustment Mechanism ("RSAM") deferral account in the 2006 ROE Decision, where it referred to two facets of the account, the first as a weather normalization account, and the second to enable TGI to defer margin variances arising from residential and commercial customers consuming more or less gas than forecast. As for weather normalization, the Commission was of the view that TGI was similar to a number of utilities in North America that can defer the effects of temperature on usage. Since weather is a symmetrical risk, with equal odds of over and underachieving, the Commission determined that it should not be taken into account when establishing return on equity.

The Commission considered the second facet of the RSAM to be a short-term business risk mitigant, which was not available to TGI's comparators.

Terasen points out that the RSAM does not mitigate the risk associated with TGI's forecast customer additions, as it only relates to use per account, and submits that with regard to the statement that margin variance accounts are not available to other utilities, that an increasing number of other utilities both in Canada and the US now have decoupling protection, which is required to ensure that a utility is not deterred from or economically disadvantaged by undertaking energy conservation programs. In those instances where per customer usage varies from forecast because incorrect values were accepted by the regulator, Terasen submits that the values would have been accepted with no symmetrical bias. Accordingly Terasen submits that neither facet of the RSAM should be taken into account when determining return on equity, and that the RSAM should not be taken into account in considering the long-term business risks of TGI. (Terasen Argument, para 46)

### 3.4 Capital Structure

All three of Terasen's expert witnesses commented on the equity ratio of TGI and compared it with major natural gas LDCs in Canada, utilities in Ontario, and US utilities.

Terasen sets out the equity ratios of the other major natural gas LDCs in Canada as follows:

| Company | Equity Ratio (%) |
|---|---|
| TGI | 35.01 |
| ATCO Gas[1] | 38.00 |
| Union Gas | 36.00 |
| Enbridge Gas ("EGDI") | 36.00 |
| Gaz Metro | 38.50 |

(1)ATCO Gas' equity ratio was increased to 39 percent by AUC Decision 2009-216.

(Source: Exhibit B-1, p. 13)

Ms. McShane also observes that ATCO Gas, Union Gas and EGDI all have preferred shares in their capital structures, whereas TGI does not, and that since 2005, the NEB has approved increases in the equity ratios of a number of gas pipelines it regulates. (Exhibit B-1, Tab 3, pp. 32-33)

Ms. McShane testified that TransCanada's increase of equity ratio to 40 percent was a result of a negotiated settlement and that she was not aware of what was traded off in return for the increase. She acknowledged that she was not aware of any regulatory agency putting weight on the equity ratios that come out of negotiated settlements. (T4:475-77)

Mr. Carmichael recommends that the Commission increase TGI's deemed equity base to at least 40 percent to achieve an appropriate stand alone financing structure. According to Mr. Carmichael, such an increase would be consistent with decisions in other Canadian regulatory jurisdictions, and primarily in Ontario, which has chosen to increase the common equity bases of i) natural gas LDCs to 36 percent for Union Gas and EGDI (in addition to their preferred shares) and ii) electric LDCs to 40 percent for Toronto Hydro and other major LDCs. The increase would also recognize that TGI must compete for debt and equity funds against thicker equity capitalized gas distribution companies from the US. (Exhibit B-1, Tab 2, p. 50)

Dr. James H. Vander Weide was retained by Terasen to: i) assess the validity of the AAM, ii) conduct an analysis of the cost of equity for TGI, and iii) recommend an appropriately fair ROE and deemed equity ratio for TGI. In his filed evidence he states that during the period 2006-08 the average approved equity ratio for US electric utilities, and for US natural gas utilities, was 48 percent and 49 percent, respectively, and that these were significantly higher than the approved equity ratio for TGI. (Exhibit B-1, Tab 4, p. 35)

JIESC submits that the only relevant changes in common equity ratios are the changes for Union Gas and EGDI, whose common equity ratios have both increased from 35 percent to 36 percent since 2005 (with the increase in Union Gas's common equity ratio being, "the result of a negotiated settlement under which presumably the interveners received value"). Since it considers TGI to be less risky than these utilities, it submits that TGI should continue to have a lower equity ratio. (JIESC Argument, p. 29)

In Reply, Terasen submits that Union Gas and EGDI have less business risk in that electric prices in the service areas of Union Gas and EGDI are higher than BC Hydro prices, and in that neither Union Gas nor EGDI are subject to government policies and legislation similar to the energy-related policies of the BC provincial government. Terasen submits that the risks of TGI are greater than those of both Union Gas and EGDI. (Terasen Reply, para 84)

### 3.5 Credit Ratings and Metrics

Terasen states that TGI's debt is currently rated by all three major debt rating agencies, Moody's, DBRS, and Standard & Poor's (on an unsolicited basis only), and that Moody's debt rating of A3 for TGI's senior unsecured debentures is the lowest rating of the three agencies and is only one level above the Baa rating category. Since it believes that bond investors are more likely to focus on the lowest rating, TGI focuses on Moody's ratings and guidelines. (Exhibit B-1, Tab 3, p. 33)

Terasen filed a Moody's report entitled *"Rating Methodology: North American Regulated Gas Distribution Industry (Local Distribution Companies),"* dated October 2006 which covers 30 gas utilities in North America (Canada and the United States). (Exhibit B-6, BCUC Attachment 111.1, p. 1)

Moody's states that the focus of its rating methodology is on the "pure" gas LDCs in North America and is concerned principally with operating utilities regulated by their local jurisdictions and not with gas utilities owned by parent holding companies that have other non-regulated businesses. TGI is the only Canadian utility included in the report, which focuses on the following core rating factors:

- sustainable profitability;
- regulatory support;
- ring fencing; and
- financial strength and flexibility.

In addition, the report analyzes factors that are common across all industries such as liquidity, corporate governance, event risk, and legal structure.

The report describes the methodology used to rate a gas utility company which focuses on the following factors and gives them the following weights:

- Sustainable Profitability
  - Return on Equity (15 percent)
  - EBIT [Earnings before Income Taxes] to Customer Base (5 percent)

- Regulatory Support
  - Regulatory Support and Relationship (10 percent)

- Ring Fencing
  - Ring Fencing (10 percent)

- Financial Strength and Flexibility
  EBIT/Interest (15 percent)
  Retained Cash Flow/Debt (15 percent)
  Debt to Book Capitalization (excluding goodwill) (15 percent)
  Free Cash Flow/Funds from Operations (15 percent).

The following table sets out TGI's ratings by Moody's and where on the "factor mapping" the ratings place TGI:

| Category | Metric/Comment | Indicated Rating |
|---|---|---|
| Return on Equity | 9%-14% | A |
| EBIT to Customer Base | >$350/customer | Aaa |
| Regulatory Support and Relationship | "Very good, proactive support" | Aa |
| Ring Fencing | "Very good provisions" | Aa |
| EBIT/Interest | 1 – 2x | Ba |
| Retained Cash Flow/Debt | 5 – 10% | Ba |
| Debt to Book Capitalization | 65 – 85% | Ba |
| Free Cash Flow/Funds from Operations | (15%) – (30%) | A |

The report notes with respect to TGI that: "Notwithstanding TGI's relatively low risk business profile, its financial profile is considered weak at the A3, senior unsecured rating level. Accordingly, further sustained weakening of TGI's financial metrics, for instance ROE below 8 percent, EBIT/Interest below 2x, RCF [Retained Cash Flow]/Debt below 5 percent and/or Debt/Book Capitalization (excluding goodwill) above 65 percent, would likely lead to a downgrade of TGI's rating." The report concludes that TGI's model rating would be a Baa1.

In its May 2009 report affirming TGI's A3 rating, Moody's cautions:

> "However, in the context of the current low interest rate environment and weaker economy, Moody's is becoming concerned that TGI's credit metrics could deteriorate to levels that, despite the relative supportiveness of TGI's regulatory environment, are not commensurate with the company's existing A3 senior unsecured rating and therefore could lead to a negative rating action...Moody's will be following the progress of TGI's cost of capital application and its pending application for 2010 rates to determine their impact on TGI's financial profile."
> (Exhibit B-3, BCUC 1.86.2)

Terasen states that a credit rating downgrade below the A rating category could lead to TGI being required to post letters of credit with its counterparties, which would incur a direct cost in the form of letter of credit fees. In addition, and of more concern, would be the potential restriction this could place on TGI's commodity hedging activities, which can extend out three years, and where given the volatility in gas prices, the mark to market exposure on a derivative can vary significantly. When TGI enters into financial hedges, it restricts its activities to A or higher rated counterparties, and, with a B rating, could face similar restrictions and be constrained in pursuing its hedging activity, to the potential detriment of its customers. (Exhibit B-1, p. 37)

The impact of a downgrade by Moody's is also considered by Ms. McShane who opines that a downgrade increases the cost of the new debt, but also affects outstanding debt. An increase in the cost of debt to a utility increases the required yield on the outstanding debt and reduces the value of that debt. Since existing holders are the most likely purchasers of future issues, a debt rating downgrade, with resulting negative impact on the value of their existing holdings, would likely make them less willing to purchase future issues.
(Exhibit B-1, Tab 3, p. 27)

JIESC submits that TGI's consistent "A" bond ratings are due to the regulatory regime and the constancy of TGI's earnings and do not appear to be in jeopardy. The JIESC submits that if the Commission does conclude that TGI's "A" rating is in jeopardy, it should "pick a low cost alternative to protect it, like the issuance of preferred shares rather than increase the equity ratio." JIESC also points out that while TGI may appear to have weak credit metrics in comparison to US utilities, it has a higher bond rating than most US utilities and submits that the credit rating which looks at utilities' total risk profile is more important than credit metrics, which represent one item assessed in determining the bond rating. (JIESC Argument, pp. 29-30)

In Reply, Terasen submits that preferred shares are inefficient, and not the appropriate means of addressing credit rating metrics, since: i) Moody's views such preferred shares more as debt instruments, and therefore the issuance of preferred shares would not address concerns with credit rating metrics, and ii) the dividends on preferred shares are not tax deductible, on a debt equivalent basis, the debt component is an expensive form of debt. (Terasen Reply, para 83)

### 3.6 Interest Coverage Ratios

Terasen states that TGI currently has one of the weaker credit metrics of the sample Canadian utilities, and is lower than the group average. Terasen compares TGI's interest coverage ratio with those of its Canadian peers as follows:

| Utility | 2005 | 2006 | 2007 | 2008 |
|---|---|---|---|---|
| EGDI | 2.29 | 1.80 | 2.24 | 2.27 |
| Gaz Metro | 2.65 | 2.45 | 2.30 | 2.21 |
| Union | 2.09 | 1.91 | 2.24 | 2.28 |
| TGI | 1.94 | 2.00 | 1.95 | 1.96 |

(Source: Exhibit B-1, Table 7.4, p. 40)

Terasen states that TGI's trust indenture provides that TGI will not issue debentures or other debt instruments other than Purchase Money Mortgages ("PMM") maturing 18 months or more after date of issue unless consolidated available net earnings are at least two times the annual interest requirements on all additional obligations (including the additional debt to be issued).

Terasen states that TGI has outstanding PMMs totalling approximately $275 million, which fall due in 2015/16 and that, while a determination has not been made, it is currently of the view that it may not be able to reissue the PMM's on maturity with the result that they will be refinanced with unsecured debentures. Since the PMM's are not subject to the issuance coverage test, while the unsecured debentures that refinance them would be, Terasen states that the refinancing of its PMM's on their maturity will lead to further constraints on the issuance coverage test.

Terasen provides Exhibit B-28, which discusses the coverage test and attaches a table which demonstrates that at 35 percent equity and an 8.43 percent ROE it would have difficulty in issuing $100 million of unsecured debt in 2009. (Exhibit B-28)

**Commission Determination**

Based on the Commission's assessment of TGI's long-term business risk in its 2006 ROE Decision, the fact that TGI has no preferred shares in its capital structure, and a comparison with the other major natural gas LDCs in Canada, the Commission Panel considers that the equity ratio of TGI, remains in the range of 35 percent to 38 percent before considering the impact of any change in TGI's long-term business risk that has occurred since 2005.

The Commission Panel agrees with the Intervenors that all risks cited by Terasen existed in 2005 with the exception of the climate change related risks and those related to First Nations.

As for the existing risks, the Commission Panel does not see how TGI's ability to earn a return on or of its capital has been adversely affected since 2005. Although all Intervenors identify the competitive position of natural gas compared with electricity as one risk which has diminished since 2005, the Commission Panel considers that natural gas' competitive edge over electricity is dependent on too many significant variables, such as the level of the carbon tax, the volatility of natural gas prices and the impact of government policy on BC Hydro's rates, to be considered permanent.

As for concerns about the risks posed by First Nations, the Commission Panel agrees with Terasen that the risks did not exist in 2005, to the extent they are currently perceived, and that they constitute an increase in risk over natural gas LDCs operating in other provinces. The Commission Panel does not consider that the risks presently cast doubt over TGI's ability to earn a return on or of its capital.

The Commission Panel agrees with Terasen that the introduction of climate change legislation by the provincial government has created a level of uncertainty that did not exist in 2005 and 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. 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.

As for the evidence that US natural gas LDCs have thicker equity ratios than their Canadian counterparts, the Commission Panel notes that no reasons for the difference were entered into evidence. The Commission Panel concludes that the difference between US and Canadian natural gas LDCs' equity ratios is not of itself determinative.

The Commission Panel considers that TGI's business risk has increased since 2005. In the Commission Panel's opinion the additional risk suggests an equity ratio for TGI of 40 percent. **Accordingly, the Commission Panel determines that the appropriate equity ratio for TGI is 40 percent effective January 1, 2010.**

**As it did in its 2006 ROE Decision, the Commission Panel requires TGI to file within 30 days of this Decision a document setting out how and when it will implement this change to its capital structure in compliance with the ring-fencing conditions approved by the Commission in its Order G-49-07.**

## 4.0 THE APPROPRIATE RETURN ON EQUITY FOR TGI

The issue that is addressed in this Section is: Given TGI's capital structure, what is the appropriate ROE for TGI and what approaches to its determination should the Commission Panel give weight?

There are several approaches used to determine ROE, none of which is universally preferred. Therefore, in order to determine the appropriate ROE for TGI, the Commission Panel must first review the main approaches for determining an appropriate ROE and decide how much weight to accord the results from each.

The approaches are reviewed in Section 4.1, below. Once they have been reviewed and the Commission Panel has determined how much weight to give to each, it then reviews, in Section 4.2, the results from each of the approaches as calculated by the various experts, to determine the appropriate ROE for TGI.

### 4.1 The Approaches used to Determine ROE

Terasen identifies three approaches used to determine ROE:

1) Discounted cash flow ("DCF");
2) Equity risk premium ("ERP");and
3) Comparable earnings ("CE").

Ms. Mc Shane states that: "Each of the tests is based on different premises and brings a different perspective to the fair return on equity. None of the individual tests is, on its own, a sufficient means of estimating the fair return; each of the tests has its own strengths and weaknesses. Individually, each of the tests can be characterized as a relatively inexact instrument; no single test can pinpoint the fair return." (Exhibit B-1, Tab 3, p. 42)

### 4.1.1 Discounted cash flow approach

Terasen submits that the discounted cash flow approach for the determination of the return on equity of regulated utilities is an approach that has been widely accepted, and widely used for many years, even though in recent years the use of the DCF approach by Canadian regulatory agencies has been limited. Terasen cites an article by Dr. Makholm from *Public Utilities Fortnightly* dated May 15, 2003 entitled, "In Defence of the Gold Standard," where Dr. Makholm stated that, "the DCF method has endured [in the US] for most of the past two decades for three basic reasons:

- It rests on a solid, straightforward theoretical base;
- It capitalizes on the depth of U.S. capital markets-meaning analysis can use "proxy groups" of publicly traded companies in the same industry to manage the variability of individual company DCF calculations; and
- It makes use of company growth projections from disinterested industry analysts-a key attribute for a method to gauge the opportunity cost of capital in the mind of investors." (Exhibit B-20)

Dr. Booth states that, "...the DCF estimate is particularly appropriate for use in determining the fair rate of return for a regulated utility." (Exhibit C11-5, Appendix C, p. 4)

JIESC submits that, "By comparison [with the Capital Asset Pricing Model ("CAPM")] DCF and comparable earnings are black boxes with numerous judgements and are much less constrained by the facts." (JIESC Argument, p. 2)

JIESC points out that the DCF approach has not been accepted by a Canadian regulator in the last 10 years. In addition it points out that Ms. McShane's discounted cash flow test uses a sample of US gas and electricity utilities and relies on *Value Line* and Thomson Reuters I/B/E/S ("I/B/E/S") forecasts for estimating earnings growth. The JIESC submits that "this [reliance] still suffers from the strong possibility of upward bias and should be subject to considerable caution before being used." (JIESC Argument, p. 39)

Terasen replies that there is no suggestion that *Value Line* forecasts suffer from upward bias, and that Dr. Vander Weide testified that studies that have purported to show upward bias have statistical errors.

Terasen takes issue with the characterization of the DCF and CE tests by JIESC as "black boxes" and submits that the criteria used by Ms. McShane in selecting companies of comparable risk are objective and explicit, and focus on characteristics to ensure comparability. The way the returns are measured in both the DCF and comparable earnings approaches are transparent, and the tests, in contrast to the CAPM, are compatible with meeting the comparable returns requirement. (Terasen Reply, para 104)

### 4.1.2 Equity Risk Premium Approach

Terasen submits that the equity risk premium test is derived from the concept that there is a direct relationship between the level of risk assumed and the return required. Since an investor in common equity takes greater risk than an investor in bonds the equity investor requires a premium above bond yields in compensation for the greater risk.

Terasen states that the Capital Asset Pricing Model ("CAPM") is one of the equity risk premium models, and is the most common, but not the only one. CAPM is based on a portfolio investment theory and relies on the premise that an investor requires compensation for non-diversifiable risks only. Non-diversifiable risks are those risks that are related to overall market factors (e.g., interest rate changes, economic growth), while company-specific risks, according to CAPM, can be diversified away by investing in a portfolio of securities; therefore, the investor requires no compensation to bear those risks. (Terasen Argument, para 296)

Under the CAPM approach, ROE is calculated using the following formula:

ROE = Risk-Free Rate + {Relative Risk Adjustment x Market Risk Premium}

In CAPM, risk is measured using the relative risk adjustment, known as beta. Theoretically, the beta is a forward looking estimate of the contribution of a particular stock to the overall risk of a portfolio. In practice, the beta is a calculation of the historical correlation between the overall equity market returns, as proxied in Canada by the returns on S&P/TSX Composite Index, and the returns on individual stocks or portfolios of stocks. (Exhibit B-1, Tab 3, p. 45)

Ms. McShane states that the "raw" betas for publicly-traded Canadian regulated gas and electric companies, the TSE Gas/Electric Index, and the S&P/TSX Utilities Sector declined significantly in the periods between 1993 and 1998 and between 1999 and 2005, and that following an increase in 2007 to 0.50, the utility betas again declined in 2008 to approximately 0.25. These "raw" betas of approximately 0.25 for Canadian utilities provide virtually no explanatory power in terms of capturing utility investors' return expectations. While that is clear, the more difficult task is to determine if and how the "raw" beta values can be translated into a relative risk adjustment that does provide an indication of the return requirements of utility investors. In order to arrive at a reasonable relative risk adjustment, the normative ("what should happen") CAPM needs to be integrated with what has been empirically observed ("what does or has happened").

Ms. McShane states that the practice of adjusting betas toward the equity market beta of 1.0, rather than the calculated "raw" betas, takes account of the observed tendency of stocks with low betas to achieve higher returns than predicted by the simple CAPM and vice-versa. Adjusted betas are a standard means of estimating betas, and are widely disseminated to investors by investment research firms, including Bloomberg, *Value Line* and Merrill Lynch. All three of these firms use a similar methodology to adjust "raw" betas toward the equity market beta of 1.0 and give approximately 2/3 weight to the calculated "raw" beta and 1/3 weight to the equity market beta of 1.0. (Exhibit B-1, Tab 3, p. 56)

Terasen contends that if beta is to be considered a reasonable measure of risk, then the use of the traditional estimate of beta in the CAPM should produce a reasonable estimate of a utility's cost of equity. It calculates that applying conventionally estimated betas for Canadian utilities using the last five years of data in the range 0.25 to 0.30 to a 5-6 percent risk premium on the Canadian market index yields a utility risk premium of 1.5 percent to 1.8 percent. Adding this utility risk premium to the May 2009 forecast yield on long Canada bonds of 3.69 percent produces a cost of equity in the range 5.19 percent to 5.49 percent. Since this result is "absurdly low" in comparison to current yields on utility bonds, Terasen concludes either that: (1) betas as traditionally measured do not correctly measure the risk of utility stocks; or (2) the CAPM does not apply to the Canadian marketplace. (Exhibit B-3, BCUC 14.5.1)

Ms. McShane calculates the "raw" beta for PNG Ltd. ("PNG") to be 0.26 for 2008 (Exhibit B-1, Tab 3, Schedule 11). Dr. Booth testified that PNG was "the riskiest Canadian utility" (T5:603).

JIESC addresses adjustment to beta, noting that Dr. Booth concluded that it is unreasonable to just use the statistical estimate without recognising the underlying events that caused it, and then to make the appropriate adjustments. JIESC submits that Ms. McShane confirmed that no regulatory agency in Canada has accepted adjusted betas and that in the TQM Decision the NEB specifically rejected adjusted betas. (JIESC Argument, p. 37)

Terasen submits that an ROE based on CAPM fails to meet the Commission's obligation to provide Terasen with the opportunity to earn a fair return on its investment in utility assets in that the CAPM methodology does not, and is not intended to, relate to the business risk associated with an investment in utility assets. Rather, it relates to how the investment in one asset (usually a security) affects the overall riskiness of a basket (or portfolio) of investments. CAPM assumes that an investor has a diversified portfolio of investments and that risk is measured only by reference to the impact that a specific investment has on the overall diversified portfolio; CAPM is not attempting to measure the business risk of a utility or other company. (Terasen Argument, para 146)

The May 2003 article from *Public Utilities Fortnightly* cited above states that:

> "CAPM, by comparison, is abstruse as a piece of theory. Further, because most of the components of the calculation are common to all companies (i.e., the risk-free rate and the market risk premium), the CAPM cannot make use of the law of large

numbers. That is to say, the problems associated with which risk-free rate to pick, or which market risk premium to adopt, hinder the result, no matter how many companies the calculation are performed upon. Finally, the CAPM has no tie to disinterested company analysts that not only reflect, but also shape, the opinions of investors. It is thus no surprise that the CAPM is vastly less popular among US regulatory commissions as a rate of return method." (Exhibit B-20)

JIESC points to page 35 of Dr. Booth's evidence where he states that CAPM is, "overwhelmingly the most important model used by a company in estimating their cost of equity capital," and cites a 2001 survey of 392 US chief financial officers ("CFOs") in the Journal of Financial Economics. Dr. Booth points out that 70 percent of the US CFOs use CAPM and a further 30 percent use a multi-beta approach similar to his two factor model to measure their own cost of equity. (JIESC Argument, pp. 33, 34)

#### 4.1.3 Comparable Earnings Approach

Terasen states that the comparable earnings approach calculates the achieved earnings returns of a sample of low-risk competitive unregulated Canadian firms over a business cycle.

The comparable earnings test is the only test that explicitly recognizes that, in the North American regulatory framework, the return is applied to an original cost (book value) rate base. The concept that regulation is a surrogate for competition means that the combination of an original cost rate base and a fair return should result in a value to investors commensurate with that of competitive ventures of similar risk.

JIESC cites six basic reasons why Dr. Booth does not use a comparable earned rate of return or comparable earnings approach:

- it is an average not a marginal rate of return;
- it is an accounting rate of return not an economic rate of return;
- it may include the impact of market power;
- it is based on non-inflation adjusted numbers;

- it is earned on historic accounting book equity that does not reflect what can be earned on investments today; and
- it varies with the firms selected in the "comparable earnings" sample.

In addition, the JIESC submits that no regulatory board or commission in Canada has given support to the comparable earnings approach in recent years and that the Alberta Energy and Utilities Board ("AEUB") very explicitly rejected its use in its 2004 Generic Cost of Capital Decision (2004-052). (JIESC Argument, pp. 40-41)

At the Oral Phase of Argument, JIESC noted that the AUC had confirmed the AEUB's 2004 finding about CE at paragraph 281 of AUC Decision 2009-216. (T6:774)

Terasen points out that in his evidence, Dr. Booth, as he had in 2005, agreed in that some of his problems with the CE test also appear in the process of setting rates under regulation, notably that both use an accounting rate of return; it is an average, not a marginal, return; it is based on historic book equity; and based on non inflation-adjusted numbers. (Terasen Argument, para 330)

Terasen submits that the *Act* requires the Commission, "to provide a fair return to the utility and what the utility invests in its infrastructure. It's a fair return to the utility. The *Act* doesn't say it has to be a fair return to the investors in the utility" and notes that the Alberta board rejected CE, "because they said it didn't deal with returns available to investors," which is not the case in BC. (T6:807)

**Commission Determination**

The Commission Panel has considered the three approaches to determining ROE for a regulated utility and agrees with Terasen that it should take all three into account when establishing an ROE. The Commission Panel agrees that the DCF and ERP are the most common approaches used by regulatory agencies in the US and that CAPM has been widely used in Canada in the period since 1994. The Commission Panel has seen no evidence that suggests: i) it should ignore the fact that the Commission gave the DCF approach weight in the 2006 ROE Decision, or ii) that would persuade it to depart from the Commission's finding in that decision that the CE methodology had not outlived its usefulness when it commented: "However, the Commission Panel is not convinced that the CE methodology has outlived its usefulness, and believes that it may yet play a role in future ROE hearings."

As for the two most commonly used approaches, the Commission Panel finds that the DCF approach has the more appeal in that it is based on a sound theoretical base, it is forward looking and can be utility specific. The Commission Panel has considered the submission of the JIESC concerning "upward bias" of analysts' estimates and considers that no allegations of upward bias have been levelled against utility analysts and that *Value Line* estimates will be free from any suggestion of upward bias. Accordingly the Commission Panel will not give any weight to suggestions of analyst bias.

The Commission Panel notes that CAPM is based on a theory that can neither be proved nor disproved, relies on a market risk premium which looks back over nine decades and depends on a relative risk factor or beta. The fact that the calculated beta for PNG (considered by Dr. Booth to be the most risky utility in Canada) was 0.26 in 2008 causes the Commission Panel to consider that betas conventionally calculated with reference to the S&P/TSX are distorted and require adjustment.

The Commission Panel will give weight to the CAPM approach, but considers that the relative risk factor should be adjusted in a manner consistent with the practice generally followed by analysts so that it yields a result that accords with common sense and is not patently absurd.

**Accordingly the Commission Panel determines that in determining a suitable ROE for TGI, it will give most weight to the DCF approach, some lesser weight to the ERP and CAPM approaches and a very small amount of weight to the CE approach.**

### 4.2 The Evidence Concerning ROE

This part of Section 4 examines the approaches used by the witnesses to develop their recommended ROEs and the results of the tests they applied.

#### 4.2.1 Discounted Cash Flow

The DCF approach was used by both Ms. McShane and Dr. Vander Weide.

Ms. McShane states that there are multiple versions of the DCF model available to estimate the investor's required return. An analyst can employ a constant growth model or a multiple period model to estimate the cost of equity. The constant growth model rests on the assumption that investors expect cash flows to grow at a constant rate throughout the life of the stock. Similarly, a multiple period model rests on the assumption that growth rates will change over the life of the stock.

Ms. McShane states that to estimate the DCF cost of equity she used both models and applied the discounted cash flow test to a sample of low risk US "pure-play" electric and gas distributors that were intended to serve as a proxy for TGI. In applying the DCF test, she states she relied solely on published forecast growth rates that were readily available to investors. In applying the constant growth model, she relied primarily on the consensus (mean) of analysts' earnings growth rate forecasts as the proxy for investors' long-term growth expectations.

To estimate the ROE, Ms. McShane selected a sample of low risk US electric and natural gas distribution utilities, which met the following criteria: were classified by *Value Line* as a gas distributor or an electric utility; had a *Value Line* Safety Rank of "2" or better; had a Standard & Poor's business risk profile of "Excellent" and a debt rating of A- or higher; was not presently being acquired; and had a consistent history of analysts' forecasts.

Thirteen utilities met these criteria of which four (Dominion Resources, Duke Energy, FPL, and Southern Co.) were electric utilities with significant regulated generating assets. (Exhibit B-1, Tab 3, pp. 64-66 and Appendix C)

Ms. McShane agreed that, with the possible exception of Southern Co., such utilities would have to raise considerable amounts of capital replacing their generating assets. (T4:570)

Dr. Vander Weide applied the DCF model to the *Value Line* electric and natural gas utilities which he selected from all the utilities in *Value Line*'s electric and natural gas industry groups that had paid dividends during every quarter and did not decrease dividends during any quarter of the past two years, had at least three analysts included in the I/B/E/S mean growth forecast, were not in the process of being acquired, had a *Value Line* Safety Rank of 1, 2, or 3, and had investment grade S&P bond ratings.

Dr. Vander Weide's selection criteria captured ten natural gas LDCs (a number of which were also featured in Moody's report attached to Exhibit B-6, BCUC 111.1) and 24 *Value Line* electric utilities. The latter included some of the largest generating utilities in the US as well as a number of combination gas and electric utilities. (Exhibit B-1, Tab 4, pp. 33, 60, 61)

Ms. McShane states that her constant growth models indicate a cost of equity of approximately 11 percent. Her two-stage model is based on the premise that investors expect the growth rate for the utilities to be equal to the analysts' forecasts (which are five year projections) for the first five years, but, in the longer-term (from year six onward) to migrate to the expected nominal long-run growth rate of 5 percent per annum in the economy, and indicates a cost of equity of approximately 10.4 percent (Exhibit B-1, Tab 3, p. 66 and Schedule 18). Ms. McShane updated her constant growth model in Exhibit B-3, BCUC 65.3 and found the result of 11 percent to be "virtually identical."

Dr. Vander Weide concludes that the cost of equity using a constant growth approach is 12.4 percent for the 24 *Value Line* electric utilities in his study and 11.5 percent for the ten *Value Line* natural gas utilities. In response to an Information Request ("IR"), he updated these percentages as of July 2009 to 11.5 percent and 11.9 percent respectively. (Exhibit B-6, BCUC 107.1)

Dr. Vander Weide testified that he did not seek to eliminate utilities which were not "pure-play" natural gas distribution utilities from his study, and that had he done so he might have eliminated Equitable Resources and Questar Corp from his *Value Line* LDCs on the grounds that both companies have significant upstream operations. This would have reduced the cost of equity for his remaining eight "pure-play" *Value Line* LDCs to "something like" 10.5 percent. (T3:388)

JIESC submits that since dividend yields for the period of January 2009 to March 2009 are "biased upwards because stock market prices were at all time lows," the utilization of these yields together with long term I/B/E/S growth forecasts by Ms. McShane will substantially overstate investors' required returns.

Terasen replies that in the response to IR in Exhibit B-3, BCUC 65.3.1, Ms. McShane had updated her results and concluded that the estimated "bare-bones" ROE derived from the constant growth DCF model was virtually identical to the 11.0 percent she had estimated at the time her evidence was filed. (Terasen Reply, para 113)

Terasen discusses the regulatory treatment of US LDCs and of TGI in its Argument. It cites the CEA report for the CGA which states in its Executive Summary: "There are of course differences in regulatory treatment from province to province and from state to state. But we find generally that there is no persistent difference in regulatory legislation or rule making between Canada and the US."

Terasen submits that the rate setting methodologies of the *Value Line* US LDCs and TGI are quite similar. Both the *Value Line* US LDCs and TGI are subject to rate of return regulations which are designed to provide the companies an opportunity to recover prudently incurred costs and earn a fair rate of return on their investments. In addition, the US LDCs and TGI both benefit from the availability of cost recovery mechanisms that are designed to reduce regulatory lag. (Terasen Argument, para 346-347)

Terasen states that most US gas utilities have automatic rate adjustment mechanisms for purchased gas costs and weather normalization, and that many US gas utilities have decoupling mechanisms that seek to stabilize revenues by "decoupling" gas rates from gas volumes. Decoupling occurs either through a rate design that allows recovery of fixed costs from fixed monthly charges, or through a revenue normalization adjustment mechanism that increases rates or refunds rates to customers for the difference between actual revenues and authorized revenues. (Exhibit B-3, BCUC 74.3)

Terasen identifies another difference in regulatory treatment in that Canadian regulatory agencies do not allow natural gas LDCs to recover deferred income taxes in the rates they charge their customers while US state regulators in the most part do (Exhibit B-11, Panel 1.1). Terasen testified that, at December 2008, TGI had $261 million of income taxes it had not collected from its customers (T3:286).

Dr. Booth states that in 1978 many US utilities faced, "significant regulatory lag that exposed utilities to inflation risk...Subsequently, two factors have largely removed this risk: the decline in inflation and the adoption of forward test years." (Exhibit C11-5, Appendix C, p. 9)

Dr. Vander Weide testified that it was no longer a "rule of thumb" that US regulatory bodies used historic test years to set rates, that there are now many that have forward-looking test years, and that those without forward-looking test periods are able to adjust their historical test periods for known and measurable changes such as commissioning a new plant or a negotiated pay increase settlement. (T3: 391)

Terasen filed the actual earned ROEs of the *Value Line* LDCs which demonstrate that of the eight "pure-play" LDCs (that is ignoring Equitable and Questar), three consistently earned less than their allowed returns and the remaining five earned at or around their allowed ROEs. By excluding Equitable and Questar, the average ROE earned by the 8 remaining *Value Line* LDCs ranged from 10.1 percent to 11.3 percent in the period 2004-2008. (Exhibit B-28)

In its Argument, JIESC quotes Dr. Booth's evidence that:

> "The regulation of US utilities suffers from the same philosophical and cultural factors in the US and there is no reason to believe that the results are any different. Without examining US regulatory practise in detail, since much of it is the result of individual state regulation, Canadian utilities seem to be regulated on a much more pro-active basis with very little regulatory lag. In contrast, it appears that US utilities sometimes go several years between rate hearings. Canadian utilities also seem to make more use of deferral accounts. As a result, there is little to be gained from looking at US utilities without making significant risk adjustments which is rarely done. However, since the underlying operations are similar and there is increasing uncontested evidence presented on behalf of the utilities, I have started to examine them". (Exhibit C11-5, Appendix G, p. 2 cited at JIESC Argument, p. 46)

**Commission Determination**

The Commission Panel agrees that Canadian data do not lend themselves to the DCF approach due to the very limited universe of stand-alone utilities in Canada and the lack of sufficient analysts' forecasts. However, the Commission Panel has also found that US data can act as a proxy for Canadian data where adequate Canadian data do not exist. Accordingly, the Commission Panel determines that the four DCF tests before it are relevant.

The Commission Panel places no weight to Dr. Vander Weide's US *Value Line* electric utilities test, since it included a large number of very large US vertically integrated utilities with significant amounts of generation assets. Not only did the inclusion of these very large US vertically integrated utilities tend to skew the results upwards, but they were not in the Commission Panel's view suitable comparators for a "pure-play" natural gas LDC like TGI.

The Commission Panel gives the most weight to Dr. Vander Weide's *Value Line* natural gas LDC DCF test and to both Ms. McShane's DCF tests. The Commission Panel eliminates the two *Value Line* gas utilities which had significant non-utility operations (Equitable and Questar) from Dr. Vander Weide's test and the four large vertically integrated electric utilities from Ms. McShane's two-stage DCF test. The Commission Panel considers a return in the range of 10.0 percent to 10.5 percent to be a starting point for determining TGI's ROE using the DCF approach.

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 LDCs enjoy. The Commission Panel notes Dr. Booth's suggestion that the risk premium required by US utilities is between 90 and 100 basis points more than utilities in Canada require may set an upper limit on the necessary adjustment. Accordingly, the Commission Panel will reduce its DCF estimate by between 50 and 100 basis points to a range of 9.0 percent to 10.0 percent, before any allowance for financing flexibility.

The Commission Panel's determination on the allowance for financing flexibility appears later in this Section.

### 4.2.3 Equity Risk Premium

Ms. McShane performs three ERP tests: i) a risk-adjusted equity market risk premium test; ii) a DCF-based equity risk premium test; and iii) a historic utility equity risk premium test. (Exhibit B-1, Tab 3, pp. 43-63)

Dr. Vander Weide performs two ERP tests, an *ex post* risk premium and an *ex ante* risk premium test. His *ex post* risk premium test measures the required risk premium on an equity investment in TGI from historical data on the returns experienced by investors in Canadian utility stocks compared to investors in long-term Canada bonds. His *ex ante* risk premium test is based on studies of the expected return on comparable groups of utilities in each month of the study period compared to the interest rate on long-term government bonds. (Exhibit B-1, Tab 4, pp. 30 and 32)

Dr. Booth relies on what he terms a 'classic' CAPM risk premium model and a two-factor model. The 'classic' CAPM estimate is based on an historic average market risk premium "adjusted" for the changing risk profile of the long Canada bond, while his two-factor model takes into account the interest rate sensitivity of utility stocks. As a check to his results he uses a DCF based utility risk premium test. (Exhibit C11-5, p. 56)

The table below summarizes the results of the tests performed:

| Witness | Test | Indicated ROE | FFA | Total ROE |
|---|---|---|---|---|
| Ms. McShane | Risk-Adjusted Equity Market Risk Premium Test | 8.75% | 0.50% | 9.25% |
| | DCF-Based Equity Risk Premium Test | 10.00%[1] | 0.50% | 10.50% |
| | Historic Utility Equity Risk Premium Test | 10.50% | 0.50% | 11.00% |
| Dr. Vander Weide | *Ex post* Risk Premium | 9.20% | 0.50% | 9.70% |
| | *Ex ante* Risk Premium | 11.40% | N/A | 11.40% |
| Dr. Booth | "Classic" CAPM | 7.00% | 0.75% | 7.75% |
| | Two-stage CAPM | 7.00% | 0.75% | 7.75% |

([1]) Revised by Ms. McShane to 9.5 percent. (T4:452)

(Source: Exhibits B-1, Tab 3, p. 63; B-1, Tab 4, p. 35; and C11-5, p. 56)

A comparison of Ms. McShane's risk-adjusted equity market risk premium test and Dr. Booth's "classic" CAPM tests show the following assumptions and results:

| | Ms. McShane | Dr. Booth |
|---|---|---|
| Long-term Canada bond yield | 4.25% | 4.50% |
| Equity risk premium | 6.75% | 5.00% |
| Relative risk adjustment | 0.65-0.70 | 0.50 |
| Indicated ROE | 8.75% | 7.00% |
| Allowance for financial flexibility | 0.50% | 0.75% |
| Total | 9.25% | 7.75% |

Prior to the Oral Phase of Argument, the Commission circulated a letter dated November 18, 2009. The letter had, as an attachment, a document similar to that which Commission staff has prepared each November in accordance with the Commission's Order G-25-94, as amended by Orders G-80-99, G-109-01, and G-14-06 for the purpose of determining the allowed return on common equity for a benchmark low-risk utility for the ensuing year. The document shows that the forecast yield on long-term Canada bonds for 2010 is 4.302 percent. (Exhibit A-12)

4.2.3.1 Ms. McShane's Results

(a) Risk-Adjusted Equity Market Risk Premium Test

For her risk-adjusted equity market risk premium test, Ms. Mc Shane uses a long-term Canada bond yield of 4.25 percent, an equity risk premium of 6.75 percent and a relative risk adjustment of 0.65-0.70 (the relative risk adjustment or beta was described in Section 4.1.2). To derive her equity risk premium of 6.75 percent she used an expected value of the future equity market return in a range of 11.0 percent-12.0 percent, based on both the Canadian and US equity market returns, from which she deducted both the near-term (2010) and the longer-term forecasts for long-term Canada bond yields of 4.25 percent and 5.25 percent respectively. (Exhibit B-1, Tab 3, p. 51)

Terasen submits that because equity risk premium tests are forward-looking, historic risk premium data need to be evaluated in light of prevailing economic and capital market conditions. If available, direct estimates of the forward-looking risk premium should supplement estimates of the risk premium made using historic data. (Terasen Argument, para 202)

Ms. McShane states that the "raw" calculated betas for the five-year period ending March 2009 of her sample of fifteen US utilities averaged 0.41, while the average reported *Value Line* beta for the sample (and the beta more likely to be relied upon by analysts and investors) was 0.66. (Exhibit B-1, Tab 3, Schedule 15)

Based on her analysis of standard deviations of market returns and betas, Ms. McShane adopts a relative risk adjustment in the range of 0.65-0.70. (Exhibit B-1, Tab 3, p. 57)

JIESC cites Dr. Booth's evidence in response to Ms. McShane's evidence: "I don't believe you can subtract the current LTC [long-term Canada bond] yield from a long run average equity return since it mismatches the underlying inflationary environments...so her procedures may over estimate the market risk premium by at least 1.0%." (JIESC Argument, p. 36)

JIESC describes Ms. McShane's adjustment to beta as" unreasonable" and submits that no regulatory agency in Canada has accepted adjusted betas and that in the TQM Decision, the NEB specifically rejected adjusted betas. (JIESC Argument, p. 37)

Terasen replies that Ms. McShane's relative risk adjustment of 0.65-0.70 is not based on the premise that the utility risk will rise to that of an average risk firm, but rather is based on the following:

- relative standard deviations of utility returns compared to the returns of other sectors of the market composite;
- the empirical evidence generally that the actual returns of low beta stocks have been higher than the theoretical CAPM would predict;

- the empirical evidence specific to Canadian utilities that the actual returns have historically been higher than the "raw" regression betas would predict; and
- the published betas, which incorporate the adjustment toward the market mean of 1.0, and which investors and analysts are likely to rely on when forming their return expectations. (Terasen Reply, para 121)

(b) DCF-Based Equity Risk Premium Test

Ms. McShane performed her DCF-based equity risk premium test by constructing monthly cost of equity estimates for a sample of low risk US gas and electric utilities as a proxy for TGI for the period 1991-March 2009 using the DCF model. Using a single variable and a two variable approach Ms. McShane concludes that the indicated cost for utility equity before any allowance for financing flexibility lay in the 9.7 percent to 10.25 percent range. (Exhibit B-1, Tab 3, pp. 59-61)

In her written evidence, Ms. McShane noted that as of the end of March 2009 the spread between A rated Canadian utility bonds and 30-year Canada bonds was approximately 345 basis points. When preparing her evidence Ms. McShane forecast that spread to decrease to approximately 225 to 250 basis points. In her direct examination at page 452 of the transcript Ms. McShane noted that the spreads had declined more than she had anticipated to a level of approximately 165 to 175 basis points. Using the spread of 170 basis points, she testified that the indicated utility cost of equity before any adjustment for financing flexibility was 9.5 percent (T4:452).

(c) Historic Utility Equity Risk Premium Test

Ms. McShane's historic utility premium test involves comparing the returns of utilities in Canada for the period 1956-2008 and electric utilities and natural gas utilities in the US for the period 1947-2008, on the grounds that, "Reliance on achieved equity risk premiums for utilities as an indicator of what investors expect for the future is based on the proposition that over the longer term, investors' expectations and experience converge. The more stable an industry, the more likely it is that this convergence will occur." An analysis of the underlying data indicates there has been no upward or downward trend in the utility equity returns and that the utility returns in both the US and Canada have, "clustered in the range of 11.0-12.0%, with a mid-point of approximately 11.5%."

Ms. McShane adopts a long-run forecast of 5.25 percent for long-term Canada bond yields, and deducts that long-run forecast from the mid-point of utility returns (11.5 percent) to derive a utility risk premium of 6.25 percent. To that utility risk premium she adds the 4.25 percent long Canada forecast for 2010 to derive an ROE of 10.5 percent for TGI for 2010. (Exhibit B-1, Tab 3, pp. 62-63)

JIESC submits that Ms. McShane's return recommendation is "excessive and unreasonable." (JIESC Argument, p. 3)

#### 4.2.3.2 Dr. Vander Weide's Results

(a) *Ex post* Risk Premium

Dr. Vander Weide measures the return experienced by investors in Canadian utility stocks from historical data on returns earned by investors in: (1) the S&P/TSX utilities stock index for the period 1956 -2008; and (2) a basket of Canadian utility stocks created by the BMO Capital Markets ("BMO CM") for the period 1963-2008, which suggests that the former had an equity risk premium of 4.3 percent and the latter 6.6 percent, which Dr. Vander Weide averages and adds the current long bond rate of 3.69 percent to derive an *ex post* risk premium ROE calculation of 9.7 percent.

Dr. Vander Weide states that the BMO CM basket contains Canadian companies that receive a higher percentage of revenues from traditional utility operations than the companies currently in the S&P/TSX utilities stock index, and includes Enbridge Inc. and TransCanada Corporation. (Exhibit B-1, Tab 4, pp. 31-32)

(b) *Ex ante* Risk Premium

Dr. Vander Weide's *ex ante* risk premium test is based on studies of the expected return on comparable groups of utilities in each month of his study period (September 1999 to February

2009) compared to the interest rate on long-term government bonds. The electric utility group yields an *ex ante* risk premium estimate of 8.0 percent, and the natural gas comparable group an *ex ante* risk premium estimate of 7.5 percent. To these percentages he adds the current long-Canada bond yield of 3.69 percent for an average indicated ROE of 11.4 percent. (Exhibit B-1, Tab 4, pp. 32-33)

JIESC submits that the methodology used by Dr. Vander Weide was selective in the period studied and used bond returns rather than bond yields in a period of falling interest rates and thus over estimates utility returns by roughly 3.4 percent. (JIESC Argument, p. 44)

#### 4.2.3.3 Dr. Booth's Results

(a) "Classic" CAPM

Dr. Booth estimates the market risk premium to be 5.0 percent and a uses a beta of 0.50 to develop a utility risk premium of 2.50 percent, to add to his long Canada yield forecast of 4.5 percent to arrive at a required rate of return of 7.0 percent. Adding in 0.50 percent for issue cost and 0.25 percent as a margin for error, he recommends a 7.75 percent fair ROE.

In his written evidence, Dr. Booth states that at the height of the financial crisis, Professor Fernandez surveyed finance professors around the world to find out what they used for the market risk premium. Dr. Booth presented the results of this survey which show that the median in the US is 6.0 percent and in Canada is 5.1 percent. Furthermore, Dr. Booth concluded that "the survey of Fernandez indicated that the 5.8 percent used by the BCUC is within the range of common values used by Canadian Professors of Finance of 5.0% and 6.0 %." (Exhibit C11-5, pp. 50-2)

Terasen submits that the Commission should put no weight on the results of the classic CAPM model of Dr. Booth. (Terasen Argument, para 299)

(b) Two Factor Model CAPM

Dr. Booth estimated a two factor model for utilities where their returns were driven by the common market factor, the TSX Composite return, as well as the return on the long-term Canada bond.

Given the measurement error involved in any statistical estimation and the sensitivity of the estimates to economic conditions, Dr. Booth regards the two models "as being the same." Terasen submits that Dr. Booth's application of the two-factor model understates the utility equity return requirement, because it uses a market risk premium which is even lower than that used by Dr. Booth in his classic CAPM approach (5.0 percent vs. 5.5 percent), and ignores other factors which have generated utility returns. This understates the actual utility market returns by close to 20 percent.

Terasen submits that the Commission should put no weight on the results of Dr. Booth's two-factor model. (Terasen Argument, para 301-305)

(c) DCF Based Utility Risk Premium

As a check for his CAPM results, Dr. Booth uses data for the US electric and gas utilities followed by Standard and Poors to estimate a DCF required rate of return from which he subtracts the ten-year US government bond yield to estimate the utility risk premium for these US utilities at 2.21 percent to 2.68 percent, which he increases to 2.96 percent. He states that if the risk premiums are valid for Canada, they would imply a fair return of 7.50 percent (long Canada yield forecast of 4.50 percent plus the 2.96 percent risk premium) to which the 0.50 percent flotation cost would be added. Although this is slightly higher than his direct estimates from the CAPM and two factor models, he states that it "needs adjusting for the yield gap between ten and 30 year debt yields but indicates that the estimates are in the right ball-park." (Exhibit C11-5, p. 77)

Terasen points out that Dr. Booth's calculations show: i) negative growth expectations in some instances, and ii) negative calculated utility risk premiums in a significant number of instances. Terasen submits that Dr. Booth's growth rate and resulting utility risk premiums do not reflect investors' expectations. Terasen further submits that the results of Dr. Booth's DCF check, and the utility risk premiums that he estimates using the DCF approach, should be rejected by the Commission. (Terasen Argument, para 311)

**Commission Determination**

For the ERP approach, the Commission Panel has considered the four "non-CAPM" tests applied by Ms. McShane and Dr. Vander Weide. The Commission Panel considers that both Ms. McShane's DCF-based equity risk premium test and Dr. Vander Weide's *ex ante* risk premium test cover too short a period to be determinative. In addition Ms. McShane computes the risk premium by deducting the current, rather than the experienced, long-term Canada bond forecast from the derived returns. In the Commission Panel's view these two tests can at best be considered checks for the witnesses' DCF tests and the Commission Panel accords them no weight.

The Commission Panel notes that Dr. Vander Weide's *ex post* risk premium test gave 50 percent weight to a BMO CM basket of companies which, in the Commission Panel's view, covered too short a period, contained too few utilities, and included energy holding companies with significant non-regulated operations. Accordingly, the Commission Panel places no weight on this basket.

The Commission Panel considers that the results of Ms. McShane's historic equity risk premium test and Dr. Vander Weide's *ex post* risk premium test yield comparable results on historic Canadian utility data. The Commission Panel finds the Canadian data adequate and, for the reasons set out in its Determination in Section 2 above, gives weight to the Canadian data and no weight to the results of US utility data contained in Ms. McShane's historic equity risk premium test. The Canadian utility data can be summarized as follows:

| | Utility Equity Return (%) | Bond Return (%) | Utility Risk Premium (%) |
|---|---|---|---|
| Ms. McShane | 12.00 | 7.80 | 4.20 |
| Dr. Vander Weide | 11.84 | 7.54 | 4.30 |
| Average | 11.92 | 7.67 | 4.25 |

The Commission Panel considers that the Canadian utility premium of 4.25 percent should be adjusted to reflect the fact that it was calculated over a period when long-term Canada bonds averaged 7.67 percent and that there is not a one-for-one relationship between the increase or decrease in long-term Canada bond yields and the utility equity risk premium. The Commission Panel accepts the evidence of Dr. Vander Weide in this proceeding described in Section 5.0 below that this relationship may range between 0.50 and 0.75 and, using the 2010 forecast long-term Canada bond yield of 4.30 percent in Exhibit A-12, establishes a range of 9.25 percent to 10.25 percent for the ERP approach, before an allowance for financing flexibility.

For the CAPM approach, the Commission Panel has considered Ms. McShane's risk-adjusted equity market risk premium test and Dr. Booth's "classic" CAPM test. The Commission Panel notes that Dr. Booth's two-factor model CAPM test is essentially the same as his "classic" CAPM test and accords it no extra weight. As Dr. Booth's DCF based utility risk premium test was used by him as a check the Commission Panel finds that it need not accord it any additional weight.

The Commission Panel establishes a CAPM estimate by using the Consensus estimate of 4.30 percent for the risk free rate, establishing an equity market premium in the range of the consensus estimate of Canadian professors of finance of 5 percent to 6 percent, and using an adjusted beta in the range of 0.60 to 0.66. This produces a "bare-bones" CAPM estimate in the range of 7.30 percent to 8.30 percent before an allowance for financing flexibility.

#### 4.2.4 Comparable Earnings

Ms. McShane states that her selection of Canadian unregulated companies was limited to industries that are characterized by relatively stable demand characteristics, as well as consistent dividend payments and relatively low earnings and share price volatility. The initial universe consisted of 490 firms on the TSX in Global Industry Classification Standard sectors 20-30, being Industrials, Consumer Discretionary and Consumer Staples and comprising thirteen major industries.

The initial selection was narrowed down to 27 companies by eliminating companies which:

- had 2007 equity less than $100 million;
- had missing or negative common equity during 1991-2007;
- were income trusts;
- had less than five years of market data;
- paid no dividends in any year 2004-2008;
- traded fewer than 5 percent of their outstanding shares in 2007;
- had stock ranked "higher risk" or "speculative by the Canadian Business Service;
- had debt rated non-investment grade, i.e., BB+ or below by either DBRS or Standard & Poor's, or for which none of the agencies report a rating; or
- had average five-year "raw" betas ending December 2007 and December 2008 in excess of 1.0.

Ms. McShane states that since unregulated companies' returns on equity tend to be cyclical, the appropriate period for measuring unregulated company returns should encompass an entire business cycle, covering years of both expansion and decline. The cycle should be representative of a future normal cycle, e.g., relatively similar in terms of inflation and real economic growth. The period 1991-2007 constitutes a full business cycle including the recession of 1991-1992.

Ms. McShane estimates that the average level of returns for low risk Canadian unregulated companies over a normal business cycle is in the approximate range of 12.5-12.75 percent. The comparative risk data indicate, on balance, that Canadian unregulated companies are somewhat riskier than utilities. The somewhat higher risk of the unregulated companies relative to the typical Canadian utility requires a modest downward adjustment. A downward adjustment of 75-100 basis points (based on the typical spread between Moody's BBB rated long-term industrial bond yields and long-term A rated utility bond yields and the relative betas of the unregulated companies and the Canadian and US utility samples) reduces the ROE to a range of 11.5-11.75 percent.

Ms. McShane states that although she considers that the arguments that a downward adjustment to the comparable earnings test results for market/book ratios are without merit, the data indicate that the market/book ratio for the overall Canadian equity market averaged approximately 2.0 times from 1991-2007, the period over which the comparable earnings test was conducted, while the market/book ratio for the sample of comparable Canadian unregulated companies averaged 2.1 times. In her view, the similarity of the lower average market/book ratio of the low risk unregulated Canadian companies relative to the Canadian equity market composites permits the inference that the sample average returns are not characterized by market power. Thus, she submits the comparable earnings results do not warrant an adjustment for market/book ratios.

Ms. McShane also does a comparable earnings test on a larger sample of US unregulated companies which suggests a higher return on equity. (Exhibit B-1, Tab 3, pp. 67-72)

**Commission Determination**

As for the CE approach, the Commission Panel has reviewed Ms. Mc Shane's selection process, the period of the study, and the results. The companies display conservative stock and debt ratings, an average market to book ratio of 2.1, and an average adjusted beta of 0.71. The Commission Panel considers that the initial results of 12.5 percent which Ms. McShane reduced to 11.5 percent suggest that an estimate of what unregulated Canadian companies of low business risk are earning on the book values of their equity may lie in the range of 10.5 percent to 11.5 percent.

#### 4.2.5 Allowance for Financing Flexibility

Ms. McShane states that a financing flexibility allowance is an integral part of the cost of capital as well as a required element of the concept of a fair return. It is intended to cover three distinct aspects:

- flotation costs, comprising financing and market pressure costs arising at the time of the sale of new equity;
- a margin, or cushion, for unanticipated capital market conditions; and
- recognition of the "fairness" principle.

Ms. McShane contends that, at a minimum, the financing flexibility allowance should be adequate to allow a utility to maintain its market value, notionally, at a slight premium to book value, i.e., in the range of 1.05-1.10, where a utility would be able to recover actual financing costs, as well as be in a position to raise new equity (under most market conditions) without impairing its financial integrity. A financing flexibility allowance adequate to maintain a market/book in the range of 1.05-1.10 is approximately 50 basis points. As this financing flexibility adjustment is minimal, it does not fully address the comparable returns standard. (Exhibit B-1, Tab 3, pp. 66-67)

Terasen states that the application of a return estimated on the basis of market values and applied to book values implies a market value just equal to book value, and drew the Commission's attention to the conclusion drawn by Alberta's Independent Assessment Team in its review of the cost of capital for the Power Purchase Arrangements in 1999, where it stated: "This is sometimes associated with flotation costs but is more properly regarded as providing a financial cushion which is particularly applicable given the use of historic cost book values in traditional rate of return regulation in Canada." TGI states that the adjustment to the market derived cost for financing flexibility rate provides a minimal increment to preserve financial integrity (i.e. market price slightly in excess of book value). (Exhibit B-3, BCUC 64.1)

Both Ms. McShane and Dr. Vander Weide propose the addition of an allowance for financing flexibility of 50 basis points to what they term the return on equity estimates derived from their DCF and equity risk premium tests, although Dr. Vander Weide does not propose to add it to his *ex ante* risk premium test.

Dr. Vander Weide testified that in the DCF model an issue discount of 2-3 percent on a utility's stock price coupled with issue costs of 5 percent "would amount to approximately 25 basis points." (T3:393)

Similarly Dr. Booth adds an allowance for issue costs of 50 basis points and 25 basis points as a "margin of error." Dr. Booth states: "However, I normally add 50 basis points as a cushion to the direct estimates in line with this practice of many regulators. This is mainly to ensure that there is no dilution and stock prices are more variable than a 10 percent floatation cost allowance would indicate." (Exhibit C11-5, p. 60)

The AUC adjusts CAPM results by adding 50 basis points to CAPM estimates on the grounds that "CAPM results likely underestimate the required market equity return by at least 50 basis points." (AUC Decision 2009-216, para 326)

**Commission Determination**

The Commission Panel finds no evidence before it to suggest that utilities in Canada trade in the market/book range of 1.05 to 1.10 that prompts Ms. McShane's recommended 50 basis point allowance for flotation costs. The Commission Panel agrees with Dr. Vander Weide that under normal circumstances flotation costs, comprising financing and market pressure costs arising at the time of the sale of new equity, require a 25 basis point addition to a ROE estimate.

The Commission Panel notes that the margin, or cushion, for unanticipated capital market conditions was used in Alberta in a situation where a formula for 20 year Power Purchase Arrangements was being established. It does not find the reference relevant in this proceeding.

As for the fairness principle, the Commission Panel agrees with the practice of the AUC of adding 50 basis points to CAPM estimates and adopts it in this proceeding.

**Accordingly the Commission Panel determines that for DCF, ERP and CAPM estimates it will add a 25 basis point allowance to recognize the cost of issuing additional equity. The Commission Panel will add an additional 50 basis point fairness allowance to CAPM estimates. The Commission Panel will make no allowance for CE estimates.**

#### 4.2.6 Fair Return on Equity

Having determined that it will accord weight to each of the three approaches and determined the appropriate ROE ranges that the approaches yielded, the Commission Panel can determine TGI's ROE.

**Commission Determination**

Earlier in this Decision the Commission Panel found that the suitable equity ratio for TGI is in the 40 percent range, and that it would consider the effect of its short-term business risk mitigators (such as RSAM and deferral accounts) in the determination of TGI's ROE.

The Commission Panel also determined that it would give most weight to the DCF approach, lesser weight to the ERP and CAPM approaches and a very small amount of weight to the CE approach.

The following table sets out the Commission Panel's determined ranges for each approach:

| Approach | Range (%) | Allowance (%) | Total (%) |
|---|---|---|---|
| DCF | 9.00-10.00 | 0.25 | 9.25-10.25 |
| ERP | 9.25-10.00 | 0.25 | 9.50-10.25 |
| CAPM | 7.30-8.30 | 0.75 | 8.05-9.05 |
| CE | 10.5-11.5 | 0.0 | 10.5-11.5 |

**Accordingly, after attaching the weight that it considers appropriate to each of the three approaches the Commission Panel determines that the ROE for TGI is 9.50 percent.**

### 4.3 Interim Rates and the Effective Date of the ROE Increase

Terasen requests that any increase in the ROE of the three utilities should be reflected in their rates effective from July 1, 2009. Prior to the commencement of the Oral Hearing, the Commission Panel considered an application by Terasen pursuant to section 89 of the *Act*, that the rates of the three utilities be made interim effective July 1, 2009. Section 89 of the *Act* is included in Appendix C to the Decision.

All Intervenors opposed Terasen's request at that time. The CEC submitted that all parties had agreement on the equity ratio and the ROE in the Commission approved settlement documents that can be found in Commission Order G-33-07. CEC acknowledged that while the 2008/2009 Negotiated Settlement Agreement ("NSA") did not preclude Terasen from applying to the Commission for a variation in its equity ratio or ROE, it submitted that it was inequitable that Terasen would seek and receive an adjustment for a period of six months of the 2008/2009 settlement period on what it termed a retroactive basis. (Exhibit C3-2)

Terasen's Reply pointed out that its request was in no way retroactive and that it was perfectly within the terms of the NSA. (Exhibit B-2)

## 5.0 THE AUTOMATIC ADJUSTMENT MECHANISM

This Section addresses the issues:

- Given TGI's appropriate ROE, does the Commission's adjustment mechanism produce an ROE that meets the fair return standard?
- If not, should the Commission retain, amend, or eliminate the adjustment mechanism?

Terasen requests that the adjustment mechanism be eliminated, with all three of its expert witnesses urging the Commission to abandon the formula.

Ms. McShane states that reliance on a formula which tracks changes in the long-term Canada bond yield, rather than the composite of factors that bear on equity return requirements, has resulted in allowed ROEs falling below levels commensurate with a fair return and that the extent to which this has happened since 1994 can be assessed by the table which compares the allowed ROEs of Canadian and US utilities set out in Section 2.3 of this Decision.

Terasen submits that the adoption of adjustment mechanism in Canada in the mid-1990s coincided with the almost exclusive use of equity risk premium and CAPM approaches for the determination of allowed ROE for utilities in Canada.

Ms. McShane testified that the crossover between Canadian and US utility returns started when regulatory commissions in Canada started to place almost all the weight on the CAPM and equity risk premium tests. (T4:565)

Terasen states that since the adjustment mechanisms were first adopted in the mid 1990s, yields on long-term Canada bonds have steadily decreased and returns on equity allowed for Canadian utilities have decreased to unprecedented low levels.

In addition the turbulence in the capital markets experienced in the last three years has led to a "flight to quality" which has created an abnormal demand for long-term Canada bonds that were already in short supply. This flight to quality has driven down the yield on the long-term Canada bonds, and consequently driven down the formulaic ROE that uses the long-term Canada bonds as a benchmark. Yet even as the allowed ROE has declined, the cost of capital for utilities has risen dramatically, as investors have demanded higher premiums for risk.

Terasen contends that if it cannot offer a return to equity to investors similar to returns available to comparable risk investments, it will be disadvantaged in competing for capital in the future, even if the capital markets return to historical norms. (Exhibit B-1, p. 23)

Mr. Carmichael points to credit rating agencies which have recently highlighted their concerns regarding the weak state of credit metrics achieved by utilities such as TGI that are regulated with an ROE formula, and which have compared such utility's lower metrics with those of US utilities that the rating agencies believe to be comparable.

Mr. Carmichael states that the financial performance of utilities in Canada lags the performance of US based utilities. This has prompted an equity analyst to suggest that ROE formulae in use by regulators in Canada are "confiscatory and fail to meet the fair return standard," while other analysts suggest that the formulae are now "broken." According to the latter group of analysts, under current financial market circumstances such formulas result in lower rates of return on common equity, while all evidence indicates that capital markets require higher returns on corporate securities reflecting the re-pricing of risk which has taken place. Debt analysts have opined that ROE results produced by the formulas "have not reflected the real world increase in the cost of capital" and "the annual ROE adjustment is not even yielding the right direction of change in the cost of capital." (Exhibit B-1, Tab 2, p. 7)

Dr. Vander Weide performs a number of tests to determine the validity of the adjustment mechanism ROE formula, the most significant of which were to examine evidence on the sensitivity of the forward looking, or *ex ante*, required equity risk premium on utility stocks to changes in interest rates in Canada and the US. He states that while the ROE adjustment formula implies that the cost of equity for TGI declines by 75 basis points for every 100-basis-point decline in the yield to maturity on long-Canada bonds, his findings support the conclusions that i) the cost of equity declines by less than 50 basis points for every 100-basis-point decline in the yield to maturity on long-Canada bonds, and ii) US regulators typically reduce the allowed ROE by less than 50 basis points when the yield to maturity on long-term government bonds declines by 100 basis points. (Exhibit B-1, Tab 4, p. 9)

According to Terasen the process of designing an automatic adjustment formula should involve a balance among the following criteria:

- it should be relatively simple to understand and apply;
- it should be based on changes in one or more reasonably available and verifiable variables;
- it should exclude changes in variables due to abnormal market events;
- it should incorporate variables which vary in a quantifiable way with the utility cost of equity; and
- it should incorporate variables which are not vulnerable to changes caused by company-specific circumstances which may not impact on the cost of equity for the utilities to which the formula applies. (Exhibit B-1, pp. 31-32)

Terasen stated that it was working on the design of such a formula, but had nothing to show for its efforts so far. (T2:87-88)

FortisBC supports Terasen's Application, including the elimination of the AAM. (FortisBC Argument, para 2)

PNG submits that, "the evidence in this proceeding demonstrates overwhelmingly that the automatic adjustment formula does not produce a fair return on common equity for BC utilities and should therefore be eliminated, at least until a more appropriate automatic adjustment mechanism can be determined." (PNG Argument, para 4)

On the other hand, Dr. Booth states that, "...I would recommend that the BCUC maintain their ROE formula indefinitely since like most such formulae in Canada it has done a remarkably good job of awarding ROEs that are within a zone of reasonableness, while minimising repetitive testimony. It is also broadly consistent with awarding allowed ROEs consistent with adjustment formulae used elsewhere in Canada." (Exhibit C11-5, pp. 3, 4)

JIESC submits that Terasen's analysis comparing US with Canadians ROEs is "oversimplified and incorrect. All of the data shows that risk premiums generally, not just for utilities, for Canada are lower that (sic) in the US. ...Canadian and US Utility and market risk premiums departed company, not when the AAM came into place, but when Canada got its financial house in order in 1997 and the US failed to do so. Up until last year Canada generally had financial surpluses and the US has faced increasing deficits." (JIESC Argument, p. 45)

Terasen observes that while in 1995 the NEB adopted an AAM similar to that adopted in BC in 1994, that in the NEB Letter Decision, the NEB determined that the RH-2-94 Decision will not continue in effect. As a result, the return on equity for the pipelines regulated by the NEB will not be determined by an automatic adjustment mechanism (Terasen Argument, para 4).

At the Oral Phase of Argument, counsel for FortisBC pointed out that the AUC had "moved away from" its automatic adjustment formula in AUC Decision 2009-216. (T6:743)

**Commission Determination**

A key consideration in the determination of whether to retain, amend or eliminate the AAM is whether the ROE produced by application of the formula for 2010 is reasonably comparable to the ROE determined by the Commission Panel from the evidence before it. The Commission's calculation of the ROE for 2010, as derived from the adjustment mechanism, is 8.43 percent, compared to the Commission Panel's determination that the appropriate ROE for TGI in 2010 is 9.50 percent. The Commission Panel determines that, in its present configuration, the AAM will not provide an ROE for TGI for 2010 that meets the fair return standard.

The Commission Panel agrees that a single variable is unlikely to capture the many causes of changes in ROE and that in particular the recent flight to quality has driven down the yield on long-term Canada bonds, while the cost of risk has been priced upwards.

In the Commission Panel's opinion, reliance on CAPM by Canadian regulatory agencies has also contributed to the divergence between Canadian and US allowed ROEs. In light of the limited weight given by the Commission Panel to CAPM in determining the ROE for TGI for 2010, it would seem inconsistent to retain the adjustment mechanism.

**Accordingly the Commission Panel directs that the AAM be eliminated. TGI is directed to complete its study of alternative formulae and report to the Commission by December 31, 2010.**

## 6.0 THE APPROPRIATE RETURN ON EQUITY FOR TGVI AND TGW

This Section looks at TGVI and TGW. The business risks of each are considered and a suitable capital structure and ROE for each are determined. It addresses the issue: Given TGI's appropriate capital structure and ROE what are the appropriate ROEs for TGVI and TGW?

TGVI and TGW request that the Commission continue to set their respective allowed returns on equity with reference to the Benchmark ROE established in this proceeding for TGI by adding a utility specific premium of 70 basis points for TGVI and 50 basis points for TGW to the Benchmark ROE.

Terasen submits that the business risks relating to TGI also relate to TGVI and TGW. All three companies are in the natural gas distribution business in British Columbia, and all three are subject to the provincial policies and legislation, and other factors that have increased the risk of TGI.

### 6.1 TGVI

TGVI requests that the Commission continue to set it's allowed ROE with reference to TGI's ROE established in the proceeding by adding a utility specific risk premium of 70 basis points to TGI's ROE.

In addition to TGI's business risk Terasen cites additional sources of business risk faced by TGVI:

- TGVI is a relatively immature LDC seeking to build a new market on Vancouver Island where it is at a competitive disadvantage caused by the differences in gas versus electric rate design methodologies;
- TGVI is burdened with the recovery of an accumulated deficit that peaked at approximately $88 million in 2002;
- TGVI faces the elimination of Provincial royalty revenues in 2012 that have ranged from $35 to $40 million in recent years and cover approximately 20 percent of the current cost of service;

- TGVI is highly dependent on industrial load related to the Vancouver Island Pulp Mill Joint Venture which is taking transportation service at its minimum allowed levels and whose contracts expire at the end of 2012, and the Island Cogeneration Project ("ICP") contract with BC Hydro whose future has been made less certain by the current climate change legislation and policy;
- TGVI faces a greater security of supply risk due the fact that all gas to the Island flows from a single source on the mainland and is also dependent on the use of undersea high pressure transmission facilities; and
- TGVI will become liable to repay $75 million of non-interest-bearing senior government debt, currently sitting as a credit to rate base, which when repaid will contribute to higher cost of service and impact the competitive position of the utility.

Terasen cites Ms. McShane's testimony in the 2005 ROE hearing as follows:

> "In my opinion, to equate TGVI to the benchmark low risk utility, an allowed common equity ratio of no less than 45-50% would be required (compared to the range of 35-40% for Terasen Gas). Terasen Gas is proposing a 40% common equity ratio for TGVI. I view the proposal as reasonable; however, the difference between the proposed 40% and the indicated range of 45-50% (mid-point of 47.5%) requires an incremental equity risk premium relative to the benchmark low risk utility return." (Exhibit B-11, Panel 1.6)

In the 2006 ROE Decision, the Commission found: "that the uncertainty surrounding the contract with BC Hydro beyond 2007 creates a significant incremental change to TGVI's business risk together with uncertainty as to the ultimate recovery of the balance on the RDDA. In addition, the uncertainty regarding the cessation of royalty payments from the Provincial Government and the need to repay the interest free loans from senior levels of government demonstrate that TGVI is exposed to considerably greater business risk than a benchmark low-risk utility. It is evident to the Commission Panel that in TGVI's case the probability of not earning a return on and of capital is considerably higher than is the case with the five "mature" gas distribution companies in Canada" (2006 ROE Decision, page 30). Based on these findings the Commission approved an equity ratio of 40 percent for TGVI and ROE 70 basis points higher than TGI.

### 6.2 TGW

TGW requests that the Commission continue to set its respective allowed ROE with reference to TGI's ROE established in the proceeding by adding a utility specific risk premium of 50 basis points to TGI's ROE.

Terasen submits that the relative risk of TGW as compared to TGI since the proceeding that led to the Commission's Order G-35-09 in April 2009, which found that a premium of 50 basis points over the Benchmark ROE was appropriate, has not changed. (TGI Argument, para 364)

**Commission Determination**

The Commission has in the past awarded both increased equity ratios and ROEs for both TGVI and TGW over those awarded TGI. The Commission Panel considers that TGVI's risk has declined since 2005 because of i) the resolution of the contract with BC Hydro at ICP and ii) greater certainty around the recovery of its RDDA balance.

**Accordingly the Commission Panel determines that TGVI's premium over TGI's ROE should be reduced from 70 basis points to 50 basis points. The Commission Panel determines that TGW's premium over TGI's ROE should remain at 50 basis points for the reasons set out in the Commission Order G-35-09.**

The Commission Panel notes that in determining TGI's equity ratio and ROE in this proceeding it has sought to determine an equity ratio for TGI that reflects its long-term business risks, while adjusting its ROE to reflect its short-term business risks. It also notes that the evidence suggests that both TGVI and TGW have greater long-term business risk than TGI while possessing similar deferral mechanisms to enable them to earn their allowed ROEs in the short-term. The Commission Panel further notes Ms. McShane's testimony that both utilities require greater equity thickness than 40 percent.

**Accordingly, the Commission directs TGVI and TGW to file with their next revenue requirement applications evidence as to what equity component best reflects their respective long-term business risks.**

## 7.0 TGI AS THE BENCHMARK UTILITY

This Section discusses the concept of the benchmark utility and what effect the Commission Panel's determination should have on other utilities in BC primarily FortisBC and PNG. It addresses the issue: What impact should the Commission Panel's determination have on the remaining utilities in BC that may be affected, namely FortisBC and PNG.

Ms. McShane observes that, "it is important to recognize that, while it may be administratively efficient to designate one utility as the "benchmark," it does not necessarily follow that (1) the designated benchmark is the lowest risk utility, or (2) that the risk of the designated benchmark utility does not change over time relative to its peers." (Exhibit B-1, Tab 3, p. 24)

In response to an Information Request as to whether TGI still considered itself a "benchmark low-risk utility" for the purposes of setting allowed ROEs, TGI replies that it has been designated "a benchmark low-risk utility" by the Commission, and points out that BC Hydro and BC Transmission Corporation have their ROE set with reference to the most comparable investor owned utility, which by virtue of size and geography has defaulted to TGI.

TGI accepts that it is has been, and will be, the benchmark utility in respect of being the "benchmark" or "standard" used to set the ROE of other utilities in BC, but does not consider itself to be "a benchmark low-risk utility" now, if it ever was. Any utility could act as the benchmark and TGI due to its size has been selected as the benchmark by the Commission in the past. (Exhibit B-3, BCUC 2.1)

PNG submits that if the Commission determines that the AAM no longer produces a fair return for the Terasen, it follows that the formula no longer produces a fair return for the other utilities subject to the formula, including PNG.

PNG states that it will assess whether any adjustment to its utility specific risk premiums are required as a result of the Commission's decision and, if adjustments are required, that it will file an update to its 2010 Capital Structure and Equity Risk Premium Application. (PNG Argument, para 3)

FortisBC seeks an order of the Commission maintaining the current regulatory framework in British Columbia whereby TGI's ROE is established as the Benchmark ROE for utilities in British Columbia, including FortisBC, as previously ordered by the Commission in Order G-14-06.

FortisBC submits that the Commission determined in 1994 that the use of a benchmark was in the public interest, and that there is no evidence in the record of this proceeding to suggest that the benchmark concept should be abandoned in British Columbia. FortisBC identifies a number of advantages that flow from a Benchmark ROE for utilities including:

- cost savings to the Commission and to Intervenors in avoiding additional, unnecessary hearings; the evidence related to economic outlook and capital market conditions need not be presented nor heard more than once;
- a consistent approach to economic outlook and capital market conditions, considered with reference to expert evidence gathered at a single point in time; and
- greater consistency with respect to ROE determinations for individual utilities from a common base.

FortisBC submits that the NSA approved by the Commission in Order G-193-08 is a performance based regulation settlement and contemplates the application of the TGI's ROE as the Benchmark ROE for FortisBC through to, at a minimum, 2011. The NSA provides for FortisBC to receive the "allowed return on equity" which is calculated by reference to the Benchmark ROE with adjustments and sharing as contemplated in the approved NSA.

**Commission Determination**

The Commission Panel notes that PNG seeks no relief in this proceeding and that it proposes to consider this Decision and to determine if any amendments to its 2010 Capital Structure and Equity Risk Premium Application are merited.

The Commission Panel agrees with FortisBC that there is no evidence on the record in this proceeding suggesting that the use of a Benchmark ROE is not in the public interest. **Accordingly the Commission Panel determines that the ROE for TGI it has determined in this proceeding should continue to serve as the Benchmark ROE for FortisBC and any other utility in BC that uses the Benchmark ROE to set rates.**

*Newfoundland & Labrador*
BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

# REASONS FOR DECISION:
# ORDER NO. P. U. 43(2009)

**IN THE MATTER OF**
the *Public Utilities Act*, RSNL 1990, Chapter P-47 (the *"Act"*) and
the *Electrical Power Control Act*, SNL 1994, Chapter E-5.1 (the *"EPCA"*) and
regulations thereunder;

**AND IN THE MATTER OF**
a general rate application by Newfoundland Power Inc. for approval of, *inter alia*,
rates to be charged its customers.

**BEFORE:**

**Andy Wells**
**Chair and Chief Executive Officer**

**Darlene Whalen, P.Eng.**
**Vice-Chair**

**Dwanda Newman, LL.B.**
**Commissioner**

(i) Cost of capital;
(ii) Automatic adjustment formula;
(iii) Adoption of accrual accounting for other post employment benefits (OPEBs) costs;
(iv) Executive compensation;
(v) Operational costs and efficiencies;
(vi) Inter-corporate transactions;
(vii) Amortization of hearing costs;
(viii) Disposition of proceeds from Kenmount Road Property; and
(ix) Mobile River Watershed dispute.

These issues are detailed in the following sections including the Board's findings on each.

## 2. Cost of Capital

As stated by the Board in Order No. P.U. 19(2003) regulated utilities are provided with the opportunity to earn a fair rate of return. To be considered fair the return must be commensurate with the return on investments of similar risk and sufficient to assure financial integrity and to attract necessary capital.

### i. Newfoundland Power and Risk

In Order No. P.U. 19 (2003) the Board found that the overall investment risk for Newfoundland Power, including business, regulatory and financial risk, is average when compared to other Canadian utilities. In this proceeding Newfoundland Power argues that it remains an average or typical low risk Canadian utility and that this has not changed since the last cost of capital review. Ms. McShane concluded that the business risk profile of Newfoundland Power has not changed materially since its last general rate application in 2007. She further concluded that Newfoundland Power would be viewed by investors as an approximate average risk utility relative to its Canadian peers. (K. McShane, Pre-filed evidence, pgs. 33; 39) Newfoundland Power also points to the changing financial market conditions since 2008. (Application, 1st Revision, pg. 3-18/8-12)

The Consumer Advocate stated in relation to Newfoundland Power's risk:

> *"Newfoundland Power has been and will continue to be a very well protected, stable, predictable, conservative, low risk utility operating in a very supportive regulatory environment where the company enjoys moderate, yet fairly steady customer growth, free from any significant competition. With only a small amount of generation, Newfoundland Power is predominantly poles and wires. In essence, it is very low risk."*
> (Consumer Advocate, Transcript, Oct. 14, 2009, pg. 25/11-20)

In his written submission (pg. 4) the Consumer Advocate states that the proposed Pension Expense Variance Deferral Account is a new risk reducer for Newfoundland Power and asks that the Board ensure that customers benefit from the low risk environment in which Newfoundland Power operates. According to Dr. Booth Canadian utilities enjoy almost a complete absence of risk. (Transcript, Oct. 22, 2009 pg 95/11-18) Dr. Booth detailed the reasons for his conclusion that Newfoundland Power is a typical low risk utility, including both low cost uncertainty and very low revenue uncertainty, a low growth, stable operating environment, good financial market access, and the attitude of the regulator. Dr. Booth concludes by saying: *"There is nothing in NP's business risk to indicate any change in its allowed risk premium: on the contrary given its lower financial risk a case can be made for a smaller risk premium relative to its peer group."* (Dr. L. Booth, Pre-filed evidence, Appendix H, pg. 23)

Mr. Cicchetti characterized Newfoundland Power as a transmission and distribution utility, operating in a low risk market under supportive regulation. (M. Cicchetti, Pre-filed evidence, pg. 15) He characterized the regulatory regime in which Newfoundland Power operates as "exceptional". (Transcript, Oct. 22, 2009, pg. 228/1)

The evidence shows that Newfoundland Power operates in a low risk environment. It is accepted that the regulatory regime is supportive with a range of mechanisms in place to mitigate risk, including the Rate Stabilization Account, the Municipal Tax Adjustment, the Weather Normalization Reserve Account the Energy Supply Cost Variance Reserve Account, the Demand Management Incentive Account, and the new Pension Expense Variance Deferral Account. Mr. Todd commented in his evidence that, while these types of regulatory mechanisms are not unique to this jurisdiction, they seem to be used more extensively in this province. (Transcript, Oct. 27, 2009, pgs. 114/24; 25; 115/1) In addition, the automatic adjustment formula and the capital budget approval process reduce regulatory uncertainty.

Newfoundland Power's operating conditions combined with the supportive regulatory environment contribute to earnings stability and, given Newfoundland Power's favourable common equity component compared to its Canadian counterparts, it can be considered to have low financial risk. There was no evidence presented of an increase in the level of financial risk for Newfoundland Power relative to its Canadian peers. For the last number of years Newfoundland Power has generally earned within the approved range of return on rate base. Under questioning from Board hearing counsel with respect to the returns produced as a result of the operation of the automatic adjustment formula since its inception in 2000, Ms. Perry confirmed that the returns have allowed Newfoundland Power to maintain its creditworthiness, even though the actual cost of equity may have declined in some years. (Transcript, Oct. 19, 2009, pgs. 113-115) It was also acknowledged that Newfoundland Power can apply to the Board for an adjustment to its cost of capital if its revenues are forecast to be lower than required to maintain its return at a reasonable level to ensure continued creditworthiness. Indeed this is the circumstance in this Application as Newfoundland Power has forecast its return for 2010 to be below that required to maintain its financial integrity and has applied to the Board for an increase in its allowed return on rate base for 2010 as a result.

While the evidence supports categorizing Newfoundland Power as low risk there was little evidence of new circumstances supporting a change from the previous finding that Newfoundland Power is an average risk Canadian utility. The evidence shows that Newfoundland Power's business risk profile has not changed. Supportive regulation continues to be demonstrated with the establishment of another deferral account to capture increased variability in pension expense. Newfoundland Power's deemed equity component continues to be set at 45%, one of the highest for a Canadian utility.

The Board acknowledges that financial market conditions have been turbulent over recent months and that there are differing views as to how the recovery will progress. While there is some evidence that Newfoundland Power may be considered low risk even vis a vis its Canadian counterparts, in the absence of better evidence and given the current financial circumstances, the Board continues to believe that it is appropriate to consider Newfoundland Power's overall risk to be average in relation to Canadian utilities.

**The Board finds that Newfoundland Power continues to be an average risk Canadian utility.**

ii. Methodologies for Estimating Return on Equity for 2010

Newfoundland Power proposes that the Board allow a return on regulated common equity of 11% for ratemaking purposes. This compares to the return on equity of 8.95% used for establishing 2008 test year rates in Order No. P. U. 32(2007) based on the settlement of the parties, and also for establishing 2009 rates based on the operation of the automatic adjustment formula.

The three expert witnesses that provided cost of capital evidence in this Application employed a variety of estimation methodologies. While all relied on the equity risk premium test, both Mr. Cicchetti and Ms. McShane used the discounted cash flow test, and Ms. McShane also used the comparable earnings test. The following table summarizes the expert recommendations.

| 2010 Return on Equity<br>Summary of Expert Recommendations | | | |
|---|---|---|---|
| **Expert Witness** | **McShane** | **Booth** | **Cicchetti** |
| **Recommended Return on Equity** | **11.0%** | **7.75%** | **9.6%** |
| **Test Results:** | | | |
| **1. Equity Risk Premium** | | | |
| Risk-Free Rate | 4.25% | 4.5% | 4.625% |
| Market Risk Premium | 6.75% | 5.0% | 6.4% |
| Beta | 0.65–0.70 | 0.50 | 0.66–0.69 |
| Utility Equity Risk Premium | - | 2.5% | 4.35% |
| Risk-Adjusted Equity Market | 4.5% | - | - |
| DCF-Based | 5.35% | - | - |
| Historic Utility | 6.25% | - | - |
| Indicated Cost of Equity | 8.75%-10.5% | 7.0% | 9.0% |
| Allowance for Financing Flexibility | 0.50% | 0.50% | - |
| Other Adjustments | - | 0.25% | - |
| **Indicated Fair Return on Equity** | **10.25%** | **7.75%** | **9.0%** |
| **2. Discounted Cash Flow** | | | |
| Indicated Cost of Equity | 10.5%-11.0% | - | 9.6% |
| Financing Flexibility | 0.50% | - | - |
| **Indicated Fair Return on Equity** | **11.0%-11.5%** | - | **9.6%** |
| **3. Comparable Earnings** | **11.50%-11.75%** | - | - |
| **Equity Ratio** | **45%** | **45%** | **45%** |

(Newfoundland Power, Written Submission, Appendix A, pg. 1 of 2)

In written submission (pgs. C-10 to C-12) Newfoundland Power notes that estimating the fair return on equity is somewhat subjective and sets out the weaknesses of each of the methodologies used by the experts for determining a fair return on equity, including:

- The capital asset pricing model, a type of equity risk premium test, uses realized past returns to estimate a future market risk premium and it is difficult to estimate relative risk or beta.
- The discounted cash flow test requires an estimate of expected future cash flows which can be difficult if a utility is not publicly traded.
- The comparable earnings test requires the determination of comparable investments and the time period over which returns are to be measured as well as a determination of the adjustments which may be required to ensure comparability.

Ms. McShane comments on these three tests:

*"Each of the tests is based on different premises and brings a different perspective to the fair return on equity. None of the individual tests is, on its own, a sufficient means of estimating the fair return; each of the tests has its own strengths and weaknesses. Individually, each of the tests can be characterized as a relatively inexact instrument; no single test can pinpoint the fair return. Moreover, different tests may be more or less reliable depending on prevailing economic and capital market conditions."* (K. McShane, Pre-filed evidence, pg. 40/993-999)

Newfoundland Power argues that Ms. McShane's evidence should be preferred given the depth of economic analysis, methodological scope, and breadth of comparative data underpinning her analysis. (Newfoundland Power, Written Submission, pg. C-32)

Dr. Booth stated that he believed that the most important thing is to use the right estimation technique and not necessarily a variety of techniques as suggested by Ms. McShane. (Transcript, Oct. 21, 2009, pgs 148/19-29; 149/1-16). Dr. Booth stated that the capital asset pricing model is overwhelmingly the most important model used by a company in estimating the cost of equity capital. Dr. Booth explained his preference for the capital asset pricing model in his pre-filed testimony (pg. 32):

*"Why the CAPM is so widely used is because it is intuitively correct. It captures two of the major "laws" of finance: the time value of money and the risk value of money. I will discuss the third law of finance the tax value of money later, but the time value of money is captured in the long Canada bond yield as the risk free rate. The risk value of money is captured in the market risk premium, which anchors an individual firm's risk. As long as the market risk premium is approximately correct the estimate will be in the right "ball-park." Where the CAPM gets controversial is in the beta coefficient; since risk is constantly changing so too are beta coefficients. This sometimes casts doubt on the model as people find it difficult to understand why betas change. Further it also makes testing the model incredibly difficult. However, the CAPM measures the right thing: which is how much does a security add to the risk of a diversified portfolio, which is the central idea of modern portfolio theory."*

The Consumer Advocate submits that neither the comparable earnings test nor the discounted cash flow test have been afforded weight by Canadian regulators for years. (Transcript, Nov. 6, 2009, pgs. 57/21-23; 91/20-21) Both Dr. Booth and Mr. Cicchetti suggested the comparable earnings test is not an acceptable measure of estimating fair rates of return. (Transcript, Oct. 22, 2009, pgs. 28/3-9; 149/13-17) Dr. Booth stated that, until the early 1990s, half of his testimony was based on the discounted cash flow analysis but using this test became problematic in Canada at that time and now he uses it largely as a reasonable risk check. He also notes that it is no longer the main methodology used by chief financial officers in the United States. (Transcript, Oct. 21, 2009, pgs. 193/24-25; 194/1-5; 149/22-25)

One of the most controversial issues raised in relation to the determination of an appropriate return on equity for Newfoundland Power was the use of U.S. comparables by both Ms. McShane and Mr. Cicchetti in both the discounted cash flow and comparable earnings tests and in some of the equity risk premium analyses. In relation to using U.S. data in the comparable earnings test Ms. McShane stated:

> *"Satisfying the comparable return standard requires consideration of returns available to comparable utilities in the U.S., given the similarity of operating and regulatory environments, the integration of the two capital markets, the small number of Canadian utilities with equity market data and the obvious circularity of comparisons limited to utilities that are all subject to similar ROE automatic adjustment mechanisms."* (K. McShane, Pre-filed evidence, pg. 2/47-52)

Mr. Cicchetti stated the U.S. comparables are similar and will provide the best estimate of the cost of equity. According to Mr. Cicchetti U.S. regulated utilities are proxies for Newfoundland Power since they have similar operating and regulatory environments, there is significant integration in the capital markets of the two countries, and rating agencies consider companies in these countries to be peers. (M. Cicchetti, Pre-filed evidence, pg. 19) In relation to the discounted cash flow test both Ms. McShane and Mr. Cicchetti acknowledged that there are no perfect comparables but that the selected U.S. companies represent reasonable proxies for Canadian utilities. Mr. Cicchetti says that each company will have its differences and you need to look at the entire picture. (Transcript, Oct 22. 2009, pg. 195/15-17) Ms. McShane stated:

> *"So no, it's not completely comparable to a Newfoundland Power. No individual utility will be. I mean, every company is unique. Newfoundland Power is unique. But if you look at the, you know, overall sample of companies and the average of the various risk measures, I mean, this is a sample that you could view as in—of comparable risk to a Newfoundland Power."*
> (Transcript, Oct. 21, 2009, pgs. 19/25; 20/1-8)

The Consumer Advocate spent a great deal of time in the hearing as well as in written submission challenging the U.S. comparables used by Ms. McShane and Mr. Cicchetti. In his written submission (pg. 49) the Consumer Advocate summarized the testimony of Dr. Booth on this issue, highlighting the important differences between the two countries, including the rate of inflation, the level of risk, regulation, event risk and macro-economic factors. Dr. Booth comments on the use of U.S. comparables:

> *"Just because US firms use the same technology as Canadian ones does **not** mean they are equivalent in risk as should by now be patently obvious. I would urge the Board to disregard recommendations based mainly on US evidence, and place primary weight on Canadian market experiences and policies that have worked rather than US policies that have not."*
> (Dr. L. Booth, Pre-filed evidence, pg. 4/15-19)

Dr. Booth said that it violates everything he has taught in international finance to accept evidence from the U.S. into Canada without making adjustments and stated specifically:

> *"The first basic rule in international finance is you cannot take interest rates or fair rate of returns for one market and of one country and apply them to another without making serious adjustments to those."*
> (Transcript, Oct. 21, 2009, pgs. 173/14-19; 174/1-5)

The Consumer Advocate argued that both Mr. Cicchetti's and Ms. McShane's evidence show why U.S. returns cannot be applied to Newfoundland Power without making adjustments. He states that Ms. McShane's comparables analysis is *"...the major factor in explaining why her*

*ROE recommendation for NP is a gross overstatement."* (Consumer Advocate, Written Submission, pgs. 29; 38)

The Board believes that, in this type of analysis, it is not enough that the chosen comparables are the best available. If this data is to be relied on it must be shown to be a reasonable proxy or that reasonable adjustments can be made to account for differences. The evidence showed significant differences in virtually all of the comparables including significant levels of non-regulated and non-utility business as well as riskier generation projects, earnings volatility, more competition and less regulatory support. While it was argued that, on balance, the U.S. comparables are reasonable proxies the Board notes the overwhelming evidence of a lack of balance as it was clear that on almost every measure Newfoundland Power would have to be considered less risky than the U.S. comparables. The Board heard evidence that the rating agencies consider U.S. companies to be peers for Newfoundland Power but the Board does not conclude from this that they are the same. Moody's comments acknowledge the differences in operations in the U.S. and Canada:

> *"NPI's Baaa1 issuer rating reflects the fact that the company's operations are exclusively based in Canada, a jurisdiction where regulatory and business environments in general are relatively more supportive than those of other international jurisdictions such as the United States, in Moody's view."* (Application, 1st Revision, Exhibit 4 - Moody's Credit Opinion, August 3, 2009)

The Board notes that the rating agencies make their own "adjustments" in these comparisons by considering the lower credit metrics to be "offsetting" factors. The Board notes that neither Ms. McShane nor Mr. Cicchetti made any adjustments to reflect differences between the U.S. and Canadian market. Ms. McShane testified that she did not see it as necessary to make any adjustments to reflect differences. (Transcript, Oct. 20, 2009, pgs. 37/25; 38/1-2) Mr. Cicchetti also does not recommend adjustments to the numbers that flow out of his discounted cash flow test using U.S. comparables although he does acknowledge that concerns in relation to the level of non-regulated business operations in some of the comparables could be taken into consideration in reference to the range of the return that was calculated. (Transcript, Oct. 22, 2009, pgs. 157/13-17; 159/9-19) Based on the evidence the Board is not satisfied that the U.S. comparables are reasonable proxies for determining an appropriate return on equity without appropriate adjustments.

While the Board acknowledges the difficulties with each of the estimation methodologies, Canadian regulators have been fairly consistent for the last ten years in using an equity risk premium model for rate setting purposes. This approach seems to have satisfied utility investor expectations as there is no evidence there has been a flight of capital in the industry. Dr. Booth was quite categorical in his opinion: *"I know of no regulatory decision in Canada over the past 20 years that has adversely affected a regulated utility."* (Transcript, Oct. 21, 2009, pg. 175/24-25) This is, in the Board's view, evidence of the protective nature of the Canadian regulatory environment and of the soundness of and even an empirical validation of the equity risk premium model. The equity risk premium test is, for the most part, based on Canadian data and, while it is necessary to forecast for the future in assessing both the market risk premium and the beta, this is the sort of exercise that the Board is accustomed to in the context of prospective regulation.

The Board principally relied on the equity risk premium test in determining a fair return for Newfoundland Power in the last two full cost of capital reviews. In addition the settlement agreement of the parties in the last general rate application proposed a return on regulated common equity for rate setting based on the equity risk premium methodology. Consistent with past practice of this Board and other Canadian regulators, and considering the evidence respecting the issues in relation to the comparable earnings and the discounted cash flow tests, especially in relation to the reliance on U.S. data without making adjustments, the Board will continue to rely principally on the equity risk premium test to estimate a fair return on regulated common equity for Newfoundland Power for ratemaking purposes.

iii. Capital Asset Pricing Model Analysis

An analysis of the appropriate return on equity for Newfoundland Power using the capital asset pricing model (CAPM) form of the equity risk premium methodology requires the determination of the:

- risk-free rate to reflect the time value of money;
- market risk premium to reflect the risk undertaken by an equity investor generally; and
- beta adjustment to the market risk premium to reflect the individual firm's risk.

a) Risk-free rate

The risk-free rates recommended by all three expert witnesses were similar with Ms. McShane recommending 4.25%, Dr. Booth recommending 4.5%, and Mr. Cicchetti recommending 4.625%. Dr. Booth commented that the risk-free rate is not an area of concern, saying that the risk-free rate is in the order of 4.25-4.5% with Ms. McShane's estimate of 4.25% having been determined earlier in the year (Transcript, Oct. 21, 2009, pg. 152/4-10). The Board is satisfied that 4.5% is a reasonable estimate of the risk-free rate.

**The Board will utilize 4.50% as the forecast of the risk-free rate to be applied in the capital asset pricing model for the 2010 test year.**

b) Market Risk Premium

Ms. McShane estimates the market risk premium to be 6.75% using the capital asset pricing model. She calculates the 1947-2008 historic arithmetic average risk premium in Canada to be 4.4% to 4.6% and in the U.S. to be 5.6% to 6.2 %. She concludes however that, because the Canadian historic bond returns are materially higher than the expected returns, the historic measured risk premium in Canada understates a reasonable estimate of the forward looking equity market risk premium. She determines her recommended market risk premium of 6.75% by subtracting the estimated long-term Canada bond yields from the long run Canadian and U.S. equity market return of 11-12%. Ms. McShane concludes that, after analysis of the trends in Price/Earnings ratios, equity market returns and bond returns, the historic equity market returns in both Canada and the U.S. provide a reasonable estimate of the forward looking equity market return.

Dr. Booth agrees with Ms. McShane's estimate of the historical earned risk premium between equities and bonds in the U.S. and Canada but does not agree with her as to the difference going forward. (Transcript, Oct. 21, 2009, pg. 154/9-14) Dr. Booth challenges Ms. McShane's assessment on the basis that there is a mismatch in the data used since she subtracts a forecast risk-free rate from the average historic long run equity returns. Dr. Booth notes that the average historic long run equity returns were in the context of inflation running at three to four percent which, on a forward looking basis, overestimates the market risk premium given the commitment by Bank of Canada to hold inflation to one to three percent. He stated:

> *"So I think her estimate of the market risk premium at 6.75 percent is high. It's high relative to what the typical person in the US and Canada, professors of finance, think that it is and I mean, it's high because there's a mismatch in the underlying inflation assumptions that reflected in historic experience versus the going-forward experience."*
> (Transcript, Oct. 21, 2009, pgs. 158/24-25; 159/1-7)

Dr. Booth estimates a market risk premium of 5%. In referencing an April 2009 survey of 884 finance professors from around the world on the market risk premium for 2008, he states:

> *"The critical number is the median, the middle guy. The middle guy in the US thinks the market risk premium is six percent. The middle guy in Canada thinks that it's 5.1 percent. The middle guy in Europe thinks it's five percent. The middle guy in the UK thinks it's five percent. I think it's five percent. So one important fact is that my estimate of the market risk premium is not a high ball, it's not a low ball. It's basically right in the middle of the pack."*
> (Transcript, Oct. 21, 2009, pgs. 155/21-25; 156/1-6)

The Board notes that the survey referred to by Dr. Booth captured market risk premiums used in 2008 but did not seek opinions as to the appropriate market risk premium moving forward into 2010. The Board also notes that, while the median was 5%, the average was 5.4%. Further, while Dr. Booth recommends 5%, he acknowledges that his recommendation may be at the low end of the range. (Transcript, Oct. 21, 2009, pg. 163/17-21) The Board finds that, in light of recent market conditions, it is reasonable to assume that the required market risk premium for 2010 will not be on the low end of the range. The Board does not believe that it is appropriate to adopt a market risk premium which is at the lower end of the historical range given that the risk-free rate has in recent years dropped well below historical averages. The Board believes that Ms. McShane's recommendation of 6.75% is high based on her use of unadjusted U.S. data, the fact that she discounted the Canadian data in reference to historic premiums, and that there is mismatching of the historical experience versus the going forward experience. Considering the circumstances the Board accepts that 6% is a reasonable market risk premium.

c) Beta

A beta is a risk measure of the sensitivity to the market and, as stated by Dr. Booth, is often the most controversial part of the capital asset pricing model. (Dr. L. Booth, Pre-filed evidence, pg. 32)

Ms. McShane states that the market risk premium needs to be adjusted to recognize the relative lower risk of utilities. She calculates the historic raw beta of the TSX Utilities Index to be 0.5, with considerable variability during certain periods. She then calculates the ratio of the standard deviation of the utility index to mean and median standard deviations of the 10 major sector indices and determines a relative risk adjustment for a Canadian utility of 0.55-0.85, which she reduces to a central tendency of 0.65-0.70. Ms. McShane also does an analysis based on the long run returns and estimates a beta of 0.70. Ms. McShane also looks to the approach of several investment firms to determine an adjusted beta of 0.67. Ms. McShane recommends a beta of 0.65-0.70. (K. McShane, Pre-filed evidence, pgs. 50-55)

Dr. Booth calculates the long run average beta for Canadian utility stocks to be 0.40-0.60 but reports that the betas have not been in the normal range for the last ten years. (Dr. L. Booth, Pre-filed evidence, pg. 41) He believes that this range is appropriate given that utility stocks are defensive stocks:

> *"Fortis barely never dropped more than 20 percent when the market was off 40 percent, and we could look throughout all of the utilities and we can see what comes through very, very clearly is they're simply not as volatile as the market as a whole. They just don't drop with the market. They don't increase with the market, which is what we call defensive stocks or low risk stocks. So there's absolutely no question that the price behavior of utility holding companies in Canada has demonstrated, yet again, that they're low risk. They're low beta stocks. They're defensive stock. So I have no problem looking at that. There are always problems with individual beta estimates because of unique things that are happening to firms, but overall what comes through clear as a bell is the low risk nature of utility stocks, the overall market risk premium, five percent, possibly six percent"*
> (Transcript, Oct. 21, 2009, pg. 162/5-25)

Dr. Booth concluded that, based on his judgment as well as the tendency of betas to revert to the long run average, it was appropriate to continue to use the normal beta range of 0.45-0.55 and assigned a beta of 0.50 to Newfoundland Power as a typical regulated utility.

The Board acknowledges that determining an appropriate beta is the most difficult aspect of the capital asset pricing model. While it is well accepted that the beta will change over time the data used by the experts is largely based on historical averages. The Board notes that the actual beta has not been within the historical average since 1998. (Transcript, Oct. 22, 2009, pg. 19/17-25) While the starting point is the historical average beta (which Ms. McShane refers to as a raw beta) the additional analysis performed by Ms. McShane provides other perspectives suggesting the historic average should be adjusted. The Board agrees with Dr. Booth that utilities are a low beta stock. However, given that betas have not recently been within historical norms and in light of the financial market conditions, the Board does not expect that the beta will be within historical averages for 2010. In this circumstance the Board relies on the evidence of Ms. McShane that there should be an upward adjustment. The Board believes that, based on the evidence, a reasonable beta for Newfoundland Power is 0.60.

d) Allowance for Financing Flexibility

The Board notes that all three experts include an allowance for financing flexibility in the equity risk premium analysis. Dr. Booth and Ms. McShane recommend 0.50% and Mr. Cicchetti recommends 0.20-0.25%. Ms McShane states that this allowance is intended to cover floatation costs, a margin for unanticipated market conditions, and recognition of the fairness principle. The Board did not include a separate allowance for financing flexibility in Order Nos. P.U. 19(2003) and P.U. 32(2007). The Board did include an allowance for financing flexibility of 0.50% in the allowed return on equity for ratemaking purposes accepted in Order No. P.U. 16(1998-1999). The evidence of all three cost of capital experts in this proceeding suggests that it is appropriate to include an allowance for financing flexibility and these recommendations were not challenged. The Board is satisfied, based on the evidence, that it is appropriate to add an allowance for financing flexibility of 0.50% to the allowed equity return for rate setting.

e) CAPM Calculation

Using the individual CAPM parameters accepted by the Board an appropriate return on regulated common equity for Newfoundland Power for ratemaking purposes can be calculated as follows:

| **CAPM Calculation** | | |
|---|---|---|
| Long term Canada Bond Yield | | 4.5% |
| Market Risk Premium | 6.0% | |
| Beta | 0.6 | |
| Adjusted Market Risk Premium | | 3.6% |
| Allowance for financing flexibility | | 0.5% |
| Total allowed risk premium for Newfoundland Power | | 4.1% |
| **Total** | | **8.6%** |

iv. Contextual Considerations

While the Board relies primarily on the CAPM approach it acknowledges that this model has limitations and looks to the other evidence in the Application to determine if it is appropriate to make further adjustments. While the Board was not guided by the results of other methodological approaches in its determination of an allowed return on equity as discussed above, these results provide the Board another check on reasonableness. The Board notes the range of returns determined using the other approaches taken by the experts is 9.0% to 11.75%.

The Board also notes that the evidence provided by Dr. Booth in relation to other measures which can provide a check on reasonableness suggests that a return on equity in the 8.5-9.0% range is reasonable. Specifically, Dr. Booth states:

*"...**For the whole period, 1988-2008 the average Statistics Canada ROE for Corporate Canada was 9.1% and the median 9.88%.** What this means is that the average firm in Canada does not earn the level of ROE requested by NP of 11.0%; yet as the chart shows there is considerable year to year volatility in the overall earned ROE that is not faced by shareholders in NP."* (Dr. L. Booth, Pre-filed evidence, pgs 29/14-16; 30/1-2)

Dr. Booth also noted the Mercer report on Newfoundland Power's pension plan:

*"...that Mercer is assuming a long run equity market return of 8.50% compared to 4.40% for fixed income which presumably included GOC debt plus some corporate and provincial debt. This implies a market risk premium of 4.10%. In my judgment this under estimates the market risk premium since Mercer's long run equity return is probably closer to the geometric then the arithmetic return, and the fixed income probably includes some non-GOC debt. However, it indicates that the finance (actuarial) professionals hired by NP have views quite close to my own."* (Dr. L. Booth, Pre-filed evidence, pg. 78/2-7)

**Table 1[1]**
**Long Term Expected Return**

| **Asset Class** | **Long Term Expected Return** |
|---|---|
| Canadian Equities | 8.50% |
| US Equities | 8.50% |
| Non-North American Equities | 8.50% |
| Fixed Income | 4.40% |
| Cash and short term | 1.90% |

[1]Dr. Laurence Booth, Pre-filed evidence, pg. 78

The Board acknowledges that looking to other return on equities allowed in Canada may have an aspect of circularity. As such the Board is not guided by these determinations. However the Board believes that the well reasoned recent decisions of other regulators in Canada can provide another check on the reasonableness of the determinations of this Board. The Board notes the November 12, 2009 decision of the Alberta Utilities Commission[1] which allowed a generic return on equity of 9.0% and the March 19, 2009 decision of the National Energy Board[2] reflecting a return on equity of 9.7% at a 40% common equity component.

v. Credit Metrics

The fair return principle requires that the Board ensure that the return on equity used for rate setting is sufficient to assure Newfoundland Power's financial integrity. It is accepted that the credit metrics of a utility provide useful information when making this assessment.

Newfoundland Power states that its current credit ratings from DBRS and Moody's are both investment grade with a stable outlook. Newfoundland Power notes that, primarily due to changes in rating methodology, Moody's upgraded Newfoundland Power's first mortgage bonds to A2 while maintaining a Baa1 issuer credit rating for Newfoundland Power. Newfoundland

[1] Information # 8
[2] CA-NP-201

Power states that Moody's commented that it believed that 2008 improvements in the credit metrics are likely to be sustained and that while Newfoundland Power's credit metrics remain somewhat weaker than those of other Baa1-rated low risk utilities this is balanced by a supportive regulatory environment. (Newfoundland Power, Written Submission, pg. C-32) Ms. Perry testified in relation to credit ratings generally:

> *"I think we're always under the microscope with respect to rating agencies. Leading into the 2008 rate case, we were starting behind the eight ball with respect to financial metrics alone and we did make improvements during that particular proceeding. I still feel like we are under the microscope with respect to our financial metrics. I do not believe that we are in that much of a better place with respect to having to maintain the financial strength of Newfoundland Power."*
> (Transcipt, Oct. 15, 2009, pgs. 163/17-25; 164/1-2)

Newfoundland Power submits that it would not be able to issue First Mortgage Bonds with the pre-tax interest coverage of 2.0 times indicated in 2010 under existing conditions. (Newfoundland Power, Written Submission, pg. C-34) Article 6.2 of Newfoundland Power's First Mortgage Bond Trust Deed states that no bond issue will be certified and delivered unless the interest coverage is at least two times after the issue. (CA-NP-26) Ms. Perry explained in testimony that if Newfoundland Power were to issue bonds in 2012, as currently planned, the interest coverage calculation would be based on 2011 earnings before taxes plus total interest including the 2012 issue (Transcript, Oct. 19, 2009, pg. 13/11-21).

In his written submission (pg. 51) the Consumer Advocate raises a note of caution in relation to credit metrics and references PUB-CA-6 where Dr. Booth states that he is not aware of any financial theory or practice that determines the allowed return off the times interest earned that was found to be fair. The Consumer Advocate submits that we have to look at whether or not the firm can raise capital and provide service. The Consumer Advocate notes that the evidence shows that Newfoundland Power's next bond issue is not expected until June of 2012. The Consumer Advocate suggests that, based on the evidence, Ms. Perry may have been mistaken when she said that Moody's would not accept Newfoundland Power having lower financial metrics within its peer group. (Consumer Advocate, Written Submission, pg. 55)

The Board acknowledges that Newfoundland Power's credit metrics are weaker than its peers, which include U.S. utilities. DBRS notes at pg. 5 of its Rating Report for Newfoundland Power dated May 5, 2008 that, while Newfoundland Power's credit metrics appear weaker than those of its peers it is offset by more stable credit metrics and business risk profile. DBRS reports that Newfoundland Power had earnings before interest and taxes (EBIT) interest coverage of 2.00x for the 12-month period ending March 31, 2008 with coverages of 2.16x to 2.47x in the five prior periods. Cash flow/adjusted debt was 11.1% with range of 11.6% to 14.9% in the prior periods.

Moody's stated in its Global Credit Research Credit Opinion dated March 6, 2009:

> *"Moody's considers a downward revision in NPI's rating to be unlikely in the near term. However, NPI's long-term ratings could be negatively impacted to the extent that Moody's perceived a reduction it the level of regulatory support combined with weaker liquidity and a*

*sustained deterioration in NPI's credit metrics such as CFO pre-WC to interest coverage of less than 2.5x, CFO pre-WC to debt in the low teens and a debt to capitalization in excess of 55%."*

The Board notes that Moody's changed its established threshold for a downgrade of Newfoundland Power in 2009, suggesting that in the current circumstances Moody's will accept lower credit metrics before considering a downgrade of Newfoundland Power. Moody's does not report on EBIT but the differences in the other two measures are:

| MOODY'S DOWNGRADE THRESHOLD | | |
|---|---|---|
| | **2007** | **2009** |
| CFO Pre-W/C to interest coverage | 3.0x | 2.5x |
| CFO Pre-W/C to debt | 15% | low teens |

(Source: Information # 4; Application, 1st Revision, Exhibit 4)

As the Board stated in Order No. P.U. 19 (2003) the Board does not regulate interest coverage but rather looks to the credit metrics as an indicator of the extent to which a return will assure financial integrity as required by the fair return standard. In Order No. P.U. 16 (1998-99) the Board found that a reasonable range of interest coverage is between 2.4x and 2.7x given the interest rates and the level of Newfoundland Power's risk at the time, noting that the range of acceptable interest coverage may shift.

In Order No. P. U. 32(2007) the Board approved the cost of capital proposed by the parties in the settlement agreement. The Board determined that the proposals would provide Newfoundland Power with the opportunity to earn a just and reasonable return on rate base that will maintain creditworthiness. The Board concluded that the order of the Board would result in forecast credit metrics that were marginally below the bottom of the range recommended by Moody's with Pre-tax Interest Coverage of 2.5x; Cash Flow Interest Coverage of 2.9x; and Cash Flow Debt Coverage of 14.9% (pgs. 23-24). The Board notes that it did not hear evidence that this resulted in a downgrading by credit rating agencies. In fact evidence was led that Newfoundland Power was upgraded with a clear positive outlook.

The evidence shows that a return on equity of 9%, with allowed common equity of 45%, will yield credit metrics which are within the parameters set out by the Board and Moody's. As set out in Exhibit 5, 1st Revision a 9% return on equity will result in Pre-tax Interest Coverage of 2.41x-2.42x, Cash Flow Interest Coverage of 3.25x-3.38x and Cash Flow Debt Coverage of 17.1%-18.2%. Absent a dramatic change in circumstances there is no evidence to suggest that Newfoundland Power is in danger of being downgraded. The Board understands that it is appropriate for Newfoundland Power's Chief Financial Officer to be concerned with ensuring an appropriate return on equity for shareholders and a healthy credit rating to ensure access to financing but the Board is satisfied based on the evidence that a return on regulated common equity of 9.0% is adequate to assure the financial integrity of the company.

vi. Return on Equity

The Board is satisfied that 9.0% is an appropriate return on regulated common equity for Newfoundland Power, given a common equity component of 45%, and considering the CAPM calculation of 8.6%, the financial market conditions, and Newfoundland Power's credit metrics.

The Board notes that this finding is generally consistent with the experts' recommendations flowing from the other tests, recent Canadian return decisions, and the other calculations of returns, historical and expected, presented in evidence. The return on regulated common equity for Newfoundland Power for 2010 to be used for ratemaking purposes is set out below:

| **Newfoundland Power 2010 Test Year<br>Allowed return on equity for ratemaking purposes** | |
|---|---|
| Long term Canada Bond Yield | 4.5% |
| Newfoundland Power Risk Premium | 4.0% |
| Allowance for financing flexibility | 0.5% |
| **Total** | **9.0%** |

**The Board is satisfied that for the 2010 test year a return on regulated common equity of 9.0%, with a common equity component of 45%, will provide Newfoundland Power the opportunity to earn a just and reasonable return on rate base that is consistent with the fair return principle and the provision of least cost reliable power.**

## 3. Automatic Adjustment Formula

In Order Nos. P.U. 16(1998-99) and P.U. 36(1998-99) the Board established an automatic adjustment formula for fixing and determining the rate of return on rate base for Newfoundland Power for 2000, 2001 and 2002. In Order No. P.U. 19(2003) the formula was again ordered to be used in setting rates for 2005, 2006 and 2007. In Order No. P.U. 32(2007) the Board approved the settlement of the parties which proposed that the formula be used in setting rates for not more than three years following the 2008 test year (i.e. 2009, 2010 and 2011). The Board specifically ordered that Newfoundland Power file a general rate application by June 30, 2010 with a 2011 test year. Newfoundland Power instead filed this general rate application in 2009 with a 2010 test year seeking a cost of capital review a full year earlier than ordered by the Board. Newfoundland Power also proposes in this Application that the use of the automatic adjustment formula be discontinued.

In Order No. P.U. 16(1998-99) the Board acknowledged the possibility that there may be circumstances which would render the use of an automatic adjustment formula inappropriate for Newfoundland Power. Specifically the Board said at pg. 104:

> *"The Board will call a hearing if circumstances change, so as to render the use of an automatic adjustment formula to be inappropriate. Without attempting to enumerate all of the circumstances which might result in a hearing being convened, the following are intended as examples:*
>
> *(a) deterioration in the financial strength of the Company, resulting in an inappropriately low interest coverage;*
> *(b) changes in financial market conditions which would suggest that the formula is not accurately reflecting the appropriate return on equity; and*
> *(c) fundamental changes in the business risk of the Company."*

Newfoundland Power proposes that the Board discontinue the use of the automatic adjustment formula given that material changes in financial market conditions have affected the fairness of the returns on equity yielded by the formula. Ms. McShane set out a detailed analysis of the operation of automatic adjustment formula in her pre-filed evidence, which is summarized as follows (pgs. 8-9):

- the extent to which the formula has moved away from a fair and reasonable level can be seen in a comparison of the allowed returns on equity of Canadian and US utilities - between 1998 and 2008 the allowed returns on equity of Canadian utilities were on average 1.4 percentage points lower than those of U.S. peers, whereas the average yield on government bonds in the two countries over the same period differed by less than .1 percent.
- an analysis of the returns on equity to the utility/Treasury bond yield spreads in the U.S. shows that the returns are positively related to the utility/government bond yield, whereas during 2008 the flight to quality pushed the actual yields and forecast yields on long-term government bonds lower while other indicators were signaling a higher cost of capital, resulting in a material narrowing of the spread between the cost of new utility long-term debt and the automatic adjustment formula return on equity.
- the increased volatility in the equity markets is an indicator of rising investor risk aversion and a rising market risk premium, with the Montreal Exchange Implied Volatility Index signaling an increase in the equity risk premium since mid-2008.
- a regression analysis of the returns on equity compared to long term treasury bond yields in the U.S. over the period 1994 to 2008 showed that the returns changed by approximately 55 basis points for every one percent change in long-term government bonds, suggesting that the cost of equity is significantly less sensitive to changes in long term government bond yields than the 80 basis points assumed in the formula.

In an exchange between Board Hearing Counsel and Newfoundland Power's Vice President of Finance and Chief Financial Officer the following comments were provided:

(Mr. Simmons)
Q. Okay. So if I could summarize what you've told me then about the automatic— the position of the company on the Automatic Adjustment Formula, the problem with the formula has not so much been its use historically, but the problem is the effect that its use will have under current market conditions. That's the first point.

(Ms. Perry)
A. That is correct, yeah.

Q. And the second point is that the company is not philosophically imposed(sic) in any way to the use of an Automatic Adjustment Formula in the future?

A. Absolutely.

Q. And the question is, is the current formula the appropriate one, and your view is that it's too early to be able to tell what changes would have to be made to improve the formula?

A. That's correct.

(Mr. Ludlow)
A. That's correct.
(Transcript, Oct. 19, 2009, pgs. 120/23-25; 121/1-23)

The Consumer Advocate supports the continued use of the automatic adjustment formula, and states in his written submission (pg. 62):

*"Having regard to the fact that NP is low risk, having transferred nearly every conceivable risk to its customers, there is no basis to say that the AAF needs to be abandoned when it would provide an 8.4% ROE for ratemaking purposes, some 65 basis points higher than Dr. Booth's fair return recommendation."*

Dr. Booth concluded that the formula has functioned appropriately since its introduction, stating:

*"...So I think that the direction of the trend, as a result of the ROE Adjustment Formula, has been absolutely correct over the last fifteen years. That does not mean to say that its correct in a mechanical way on an annual basis, so I've never said that it's absolutely correct. No mechanical forecast can be absolutely correct, it's going to over and under predict slightly over the business cycle and that's why I have no objection to supporting the continuation of the ROE Adjustment Formula, even though its 40 or 50 basis points higher than what I think is a fair ROE. So I think overall the direction of the ROE formula has been absolutely correct, but it doesn't mean to say that it's absolutely correct on a year-to-year basis, given changes in the capital markets."*
(Transcript, Oct. 21, 2009, pgs. 168/20-25; 169/1-17)

Dr. Booth believes that financial markets are now returning to normal with liquidity spreads coming down and the economies of the U.S. and Canada recovering. While he believes that credit spreads are still higher than expected he does not believe this justifies a change. (Transcript, Oct. 22, 2009, pgs. 57; 58) The Consumer Advocate notes that, while the credit spread in the spring of 2009 on Newfoundland Power's 2009 first mortgage bond was 2.75%, this had dropped to 1.87% by the fall of the year. The Consumer Advocate points to comparable credit spreads for bonds issued in 2002 of 1.85%, 2005 of 1.06%, and 2007 of 1.40%. (Consumer Advocate, Written Submission, pg. 60)

Mr. Cicchetti states in his report (pg. 4):

*"Regarding the automatic adjustment formula, I believe recent changes in financial market conditions cause the formula to produce a return below the bottom of a reasonable range of the cost of equity for the Company. If the formula were to be implemented for Newfoundland Power as of August 14, 2009, it would produce an allowed return of 8.5 percent, or 50 basis points below the bottom of the range I have determined as a reasonable range of the cost of equity for the Company."*

Mr. Cicchetti cites financial market conditions over the past year which have resulted in particularly low yields on Canadian long-term government bonds, relatively high yields on corporate bonds, and declines in equity values.

Newfoundland Power bears the burden of showing that it is appropriate to discontinue the use of the automatic adjustment formula, a well-established regulatory tool that was expected to be used to set rates for Newfoundland Power in 2010. The Board is not persuaded by the evidence of Ms. McShane as to the historical underperformance of the formula, especially given the evidence of both Ms. Perry and Mr. Ludlow that the automatic adjustment formula established appropriate rates of return on rate base for almost a decade until the extraordinary financial market conditions which developed late in 2008. (Transcript, Oct. 19, 2009, pgs. 114/21-25; 115/1-25; 116/1-8)

In support of discontinuing the use of the formula Newfoundland Power notes that the formula is being reviewed in other provinces and cites a recent decision of the National Energy Board where it discontinued the use of the formula. While the Board has regard for approaches taken by other Canadian regulators, the Board finds that the circumstances of this Application are substantially different, involving a single utility with a relatively small customer base and evidence that stability in financial market conditions may be returning. As such the Board will make its decision based on the evidence presented in this hearing without regard to the approach taken by other Canadian regulators.

In Order No. P.U. 16(1998-99) the Board established the automatic adjustment formula stating (pg. 103):

> *"The Board is of the view that there is merit to a formula, in light of the cost burden of a full cost of capital hearing and the potential savings to consumers which could be realized. The Board also believes that the adoption of an automatic adjustment mechanism will create greater predictability, which will thereby reduce the risk of regulatory uncertainty. In the opinion of the Board, a mechanism to facilitate an annual review at modest costs will be of benefit to the ratepayer and to the Company."*

The automatic adjustment formula is a mathematical expression of the equity risk premium methodology which is the approach favored by Canadian regulators and the one used by this Board to determine the appropriate cost of equity for rate setting purposes for Newfoundland Power in 2010 in this Decision. In years beyond the test year Newfoundland Power's return on rate base and customer rates are established by the formula which adjusts the risk premium determined by the Board in the general rate application by a factor to reflect the change in the risk-free rate.

The Board believes that the automatic adjustment formula is fundamental to the multi-year regime in place in this province and contributes to regulatory predictability and certainty. The Board supports the comments of Mr. Todd in his report (pg. 2):

> *"The existing multi-year regime serves two purposes that are similar to the incentive regulation and performance based regulation regimes that have been adopted in some other jurisdictions:*

*they reduce regulatory cost by reducing the frequency of GRA's and they provide an incentive for the Company to pursue productivity gains in the non-GRA years."*

A general rate application is a time consuming and expensive regulatory proceeding the cost of which is generally borne by consumers. The Board notes that Newfoundland Power has requested approval to include $750,000 in the test year revenue requirement to recover the costs of this application. The revenue requirement for 2010 also includes $200,000 of outstanding hearing costs associated with Newfoundland Power's last general rate application. In addition Newfoundland Power has proposed that $315,000 be included in the 2010 revenue requirement for regulatory costs intended to cover ongoing regulatory matters possibly including a future general rate application from Newfoundland Power. These regulatory costs are significant and, if approved, will be collected in rates each year until the next general rate application. The automatic adjustment formula has been a useful regulatory tool to effectively reduce these types of costs in the past.

The evidence before the Board shows that the operation of the formula for 2010 as ordered by the Board in Order No. P.U. 32(2007) results in a forecast cost of regulated common equity for Newfoundland Power of 8.48%. (Undertaking # 10, 1st Revision) In this Application each of the cost of capital experts provided an opinion as to the fair 2010 return on equity for Newfoundland Power, ranging from 7.75% to 11.75%. In evaluating these opinions the Board rejected the evidence presented in relation to the comparable earnings test and the discounted cash flows as they related to U.S. utilities. Absent these methodologies the evidence suggests a return on regulated common equity in the range of 7.75% to 10.25%. The return on equity accepted as reasonable by the Board for Newfoundland Power for 2010 is 9%. The return on rate base which would have been generated by the formula is in the range suggested by the evidence of the cost of capital experts and, while lower than determined by the Board, does not suggest that there is a fundamental issue with the application of the formula.

Formulaic approaches to the determination of a return on equity do not allow for the exercise of discretion based on a comprehensive review of all the relevant circumstances at the time. The Board believes that the benefit of a cost of capital hearing must be weighed against the significant costs to customers. While it is clear that financial market conditions were unstable in late 2008 and early 2009 Newfoundland Power did not demonstrate that the use of the automatic adjustment formula is inappropriate for future years. Discontinuing the formula at this time would in the Board's view, be an excessive response to financial market conditions which, while severe in the fall of 2008 and spring of 2009, appear to be settling. The Board believes that it is appropriate to continue to use a formula to adjust Newfoundland Power's return on rate base for several years following a full review in a general rate application. Therefore the Board will order the continued use of the automatic adjustment formula for 2011 and 2012.

In this Application Newfoundland Power sought the discontinuation of the formula and did not provide alternatives for consideration of the Board. Mr. Ludlow, Newfoundland Power's CEO, stated that Newfoundland Power is not yet ready to discuss alternatives. Ms. Perry, the CFO, stated that she believed it was too early to propose changes. The Board does not agree and will require the formula to be used for 2011 thereby allowing almost a year to determine and implement appropriate changes. Newfoundland Power will now have the opportunity to consider and propose changes to the formula to address any concerns.

There are a number of alternatives and modifications to the existing formula and the associated processes that can be considered, including the use of consensus forecast for the risk free rate or the adoption of a different market risk premium adjustment factor. Ms. Perry raised the timing of the determination of the risk-free rate as a concern with the operation of the formula as it relates to general rate application decisions. Ms. McShane suggested that the utility cost of equity is considerably less sensitive to changes in long-term government bond yields than the existing formula suggests. Mr. Cicchetti suggested some possible improvements to the formula such as adjustment of the risk premium to reflect more recent market data and the use of a consensus forecast for the risk-free rate. Now that the question of the use of the automatic adjustment formula has been settled the parties can put their efforts to identifying ways in which this regulatory mechanism can be improved.

Newfoundland Power may apply to the Board by March 15, 2010 proposing changes to the automatic adjustment formula mechanism. The Board encourages Newfoundland Power to involve the Consumer Advocate in its analysis well in advance of filing its application with a view to encouraging consensus proposals and timely decision making that will allow for implementation of any changes in the determination of rates for January 1, 2011. In the absence of an application to modify the existing automatic adjustment mechanism the current formula will be used to adjust rates for 2011.

**Newfoundland Power may submit a proposal to the Board by March 15, 2010 for changes to the existing automatic adjustment mechanism. The Automatic Adjustment Formula will be used to set the rate of return on rate base for 2011 and 2012.**

## 4. Other Issues

### i. Other Post Employment Benefits

Newfoundland Power offers other post employment benefits ("OPEBs") to its employees which include hospital care, prescription drugs, vision care, other medical, life insurance and retirement allowances.

On January 1, 2000 Newfoundland Power adopted for financial reporting purposes the accrual method of accounting for OPEBs as required under CICA 3461-Employee Future Benefits. The accrual basis of accounting requires Newfoundland Power to recognize expenses during the period to which benefits relate. Newfoundland Power uses the cash basis of accounting for OPEBs expenses for regulatory purposes, which recognizes expenses when benefits are paid.

In Order No. P.U. 19(2003) the Board approved Newfoundland Power's proposal to continue to use the cash basis for recognizing OPEBs expenses for regulatory purposes. However the Board stated:

THE ISLAND REGULATORY AND APPEALS COMMISSION
Prince Edward Island
Île-du-Prince-Édouard
CANADA

Docket UE20940
Order UE10-03

# IN THE MATTER of an

application by Maritime Electric Company, Limited for approval of amendments to rates, tolls and charges.

# BEFORE THE COMMISSION

on Monday, the 12th day of July, 2010.

Maurice Rodgerson, Chair
John Broderick, Commissioner
Anne Petley, Commissioner
Ernest Arsenault, Commissioner

# Order

Compared and Certified a True Copy

(Sgd) *Allison MacEwen*

Director, Technical and Regulatory Services

# IN THE MATTER of an

application by Maritime Electric Company, Limited for approval of amendments to rates, tolls and charges.

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IN THE MATTER of an application by Maritime Electric Company, Limited for approval of amendments to rates, tolls and charges.

# Appearances & Witnesses

1. **For Maritime Electric Company, Limited**
   Counsel:
   Spencer Campbell
   Thomas Laughlin

   Witnesses:
   Fred J. O'Brien, President & Chief Executive Officer
   John D. Gaudet, Vice President, Corporate Planning & Energy Supply
   J. William Geldert, Vice President, Finance & Administration, Chief Financial Officer & Corporate Secretary
   Steven D. Loggie, Vice President, Customer Service
   Kathleen C. McShane, Consultant, Foster Associates, Inc.

2. **For the Minister of Environment, Energy & Forestry, Government of Prince Edward Island**
   Counsel:
   J. Gordon MacKay

   Witnesses:
   Laurence D. Booth, Consultant
   Wayne MacQuarrie, PEI Energy Corporation

3. **Interveners**
   Roger King, PEI Senior Citizens' Federation
   Matthew MacCarville, Environmental Coalition of PEI
   John te Raa, Private Citizen

4. **Public Participants**
   Ernest Mutch & John Jamieson, PEI Federation of Agriculture
   Elwin Wyand, Edith Ling, Douglas Campbell and David Best, National Farmers Union District 1, Region 1
   Harold MacNevin, Dairy Farmers of Prince Edward Island

5. **For The Island Regulatory and Appeals Commission**
Counsel:
Ryan P.MacDonald

Staff:
Allison MacEwen, Director, Technical & Regulatory Services
Mark Lanigan, Senior Analyst, Technical & Regulatory Services
Linda Allen, Recording Secretary

IN THE MATTER of an application by Maritime Electric Company, Limited for approval of amendments to rates, tolls and charges.

# Reasons for Order

## 1. Introduction & Background

[1] This is an application under the ***Electric Power Act***, R.S.P.E.I. 1988, Cap. E-4, by Maritime Electric Company, Limited (the "Applicant", "Maritime Electric" or the "Company") seeking, among other things, an Order or Orders of the Island Regulatory and Appeals Commission (the "Commission") approving amendments to the rates, tolls and charges for electric service for the period beginning August 1, 2010, and reconsideration of the 2nd block rate elimination.

[2] The Application was filed pursuant to Section 20(1) of the *Electric Power Act* (the "***Act***") which reads as follows:

| | |
|---|---|
| Variation of rates, submission for review and approval | 20. (1) Whenever any public utility wishes to vary any existing rates, tolls or charges, or to establish any new rates, tolls or charges for any service, it shall submit for the review and approval of the Commission a schedule of such proposed rates, tolls and charges together with and appended thereto all rules and regulations which, in any manner, relate to the rates, tolls and charges; the Commission may approve, after reviewing the schedule and rules and regulations submitted, the schedule of rates, tolls and charges and the rules and regulations either in whole or in part, or may determine and fix new rates, tolls and charges, and amend the rules and regulations as it sees fit. 2003,c.3.s.10. |

[3] The Company's original application filed with the Commission on January 29, 2010 requested the following:

1. Approval to rebase the Energy Cost Adjustment Mechanism ("ECAM") which would increase the base charge for energy to $0.0940/kWh in 2010 and $0.0960/kWh effective April 1, 2011;
2. Permission to file an updated report on ECAM rebasing to the Commission by November 30, 2010;
3. Approval to continue the Point Lepreau replacement energy deferral, as well as approval of a 25-year amortization period for deferred replacement energy costs, beginning with the return to service expected March 1, 2011; and
4. Approval of a maximum allowed Return on Average Common Equity of 9.75 per cent for 2010 and 2011.

[4] In February, 2010 the Commission published a Notice of Application in local newspapers seeking public input. The following summarizes the responses received:

> The PEI Senior Citizens' Federation and affiliate senior clubs across PEI filed petitions signed by members of each local club stating:
>
> > "We the undersigned request that IRAC hold a public hearing to review the 2010 Rate Change Application submitted by Maritime Electric."
>
> In addition, several of the petitions included letters from seniors which provided various comments such as:
>
> a) the need for MECL to use time-of-day rates;
> b) the Company should be required to "think outside the box and use more hydro, nuclear and wind power";
> c) a public hearing like last year's would be useful to assist with their understanding;
> d) concerns about the refurbishment of Point Lepreau, replacement energy costs and rate implications;
> e) the elimination of the second block and the lack of information on the impact on certain customers; and
> f) energy charge increases and the Company's conflicting statement of no cost increases in 2010.
>
> The Federation of Agriculture provided correspondence on March 4, 2010 stating that the current application, along with a previously issued IRAC Order (UE08-01), have implications for the agricultural sector on PEI. The Federation suggested that a public hearing be held where they could participate and present their concerns.

The Commission received either directly, or via copy, three pieces of correspondence from Mr. John te Raa. The correspondence contained questions and referenced the need for full consideration of the true cost of electricity in setting rates. No mention was made regarding the requirement to hold a public hearing.

Mr. Roger King filed two emails with the Commission. His first email indicated that the Company's rate application is written in a confusing manner, does not explicitly state the rate changes proposed, and that the Company does not "think outside the box". Mr. King also stated that electric heat is the most efficient and is more environmentally-friendly, and that a combination of in-floor and domestic hot water heating with a "time of day" tariff is one obvious alternative to a second block rate. As well, he requested a public hearing be held to allow for full public input.

In his second email, Mr. King provided comments on Commission Order UE08-01 suggesting that the wording is unclear. He also stated that the elimination of the declining block is just one issue of many "requests for change" in the 2010 application that affect customers in both the short and long term. Mr. King concluded his email by stating that "a public hearing is necessary to have all public issues resolved where facts are sorted from fiction and Islanders are told one common and correct story".

Ira Smith provided a letter to the Commission expressing concern and support regarding the continuation of the Point Lepreau replacement energy deferral. Also, she stated the cost of the replacement energy and refurbishment costs should be incurred by today's consumers and not our children and grandchildren.

The Province of PEI, by letter dated February 19, 2010, filed a Notice of Intervention and requested the Commission schedule a public hearing for the purpose of the presentation of oral evidence with respect to this application. The Province also filed a series of interrogatories with respect to this application.

On March 2, 2010 the Hon. Richard Brown, Minister of Environment, Energy and Forestry, wrote the Commission requesting the Commission review and rescind Order UE08-01 with regard to the elimination of the reduced second block rate.

In addition, on March 5, 2010 Maritime Electric wrote the Commission seeking approval to suspend the implementation of UE08-01 based on the following reasons:

a. Discussion between Governments of PEI and Quebec concerning a potential energy supply agreement which would change electricity pricing in PEI beyond a reduced second block;
b. The need for a further cost allocation study which may impact all rates;
c. Further development of an updated Demand Side Management plan ("DSM"); and
d. Reconsideration of the reduced second block as part of the pending 2010 rate application will allow all interested parties, who have expressed concerns about the public awareness and lack of consultation of the reduced second block elimination, an opportunity to make their views and evidence known to the Commission.

[5] The Commission issued Order UE10-01 on March 9, 2010 which delayed the final step in the elimination of the second block rate, directed the Company to file further information on this issue, and instructed the Company that the 2nd block tariff would be reviewed as part of the 2010 rate application.

[6] Following the significant public interest in this application, in April, 2010, the Commission published a notice in local newspapers inviting parties to participate in a public hearing. Anyone interested in participating as an intervener was advised to file a Notice of Intervention stating their reason for intervention and invited interveners to present their evidence. Four (4) parties registered as interveners in this application:

- Government of PEI, as represented by the Minister of Environment, Energy and Forestry;
- PEI Senior Citizens' Federation, represented by Mr. Roger King;
- Environmental Coalition of PEI (ECO PEI), represented by Mr. Matthew MacCarville; and
- Mr. John te Raa, as a private citizen.

[7] Commission staff conducted two pre-hearing conferences with all parties participating. A process for interrogatories, Company responses and filing of expert and intervener evidence was agreed upon. The Commission website published all information filed making the information available to all parties and the general public.

[8] The public hearing was held June 14, 2010 thru June 18, 2010 in the Commission's main hearing room. The hearing participants included Mr. Spencer Campbell and Mr. Thomas Laughlin, legal counsel for Maritime Electric, Mr. Gordon MacKay, legal counsel for the Government of PEI, PEI Senior Citizens' Federation represented by Mr. Roger King, Environmental Coalition of PEI represented by Mr. Matthew MacCarville, and Mr. John te Raa, representing himself.

[9] Three groups—PEI Federation of Agriculture, as represented by Mr. Ernie Mutch and Mr. John Jamieson; National Famers Union Region 1 District 1, represented by Mr. Elwin Wyand, Ms. Edith Ling, Mr. Douglas Campbell and Mr. David Best, and Dairy Farmers of PEI, represented by Mr. Harold MacNevin—requested and received permission to speak at the hearing. All three groups spoke on behalf of the PEI farming community.

[10] There were members of the media in attendance; however, few members of the public attended the proceedings.

# 2. The Application

[11] The Company's original application filed with the Commission on January 29, 2010 requested approval of the following:

1. Rebasing of the Energy Cost Adjustment Mechanism ("ECAM") which would increase the base charge for energy incorporated into customer billings to $0.0940/kWh in 2010 and $0.0960/kWh effective April 1, 2010;
2. Filing of an updated ECAM rebasing report by November 30, 2010;
3. Continuation of the Point Lepreau replacement energy deferral and approval of a 25-year amortization of these deferred replacement energy costs beginning with the return to service expected to be March 1, 2011; and
4. Approval of a maximum allowed Return on Average Common Equity of 9.75 per cent for 2010 and 2011.

[12] The application incorporated the final step in the elimination of the second block reduced rate, which was approved in 2008 by Commission Order UE08-01 following a public process.

[13] As well, the Costs Recoverable from Customers (Post 2003)—or ECAM—balance, excluding Point Lepreau, is forecast to be $6,316,300 at the end of 2010 and $8,800,000 at the end of 2011. The Point Lepreau replacement energy costs to be recovered from customers, assuming a 25-year amortization beginning March 2011, would be $43,100,000 at the end of 2010 and $45,800,000 at the end of 2011.

[14] The application states there is no change requested in the monthly service charge for the various rate categories. The company proposes the consumer energy rate for electricity consumed will change from $0.1178 kWh for the first 2,000 kWh/month and $0.0914 kWh for the remaining monthly consumption, with a new combined rate of $0.1355 kWh month.

[15] The application would see the residential consumer using 650 kWh/month (or 7,800 kWh/year) experience a forecast annual electricity cost reduction of (0.5%) and (0.4%) in 2010 and 2011.

[16] The Company stated the application contains just and reasonable proposals which balance the interests of Maritime Electric and its customers and allows the Company to provide a high level of service at prices which are reasonable based upon their costs.

[17] On April 8 and 12, 2010 the Company filed supplemental affidavits requesting the Commission approve an amended application which proposed:

1. A continuation of the 2,000 kWh/month 2nd energy block pricing;
2. Rebasing of the Energy Cost Adjustment Mechanism ("ECAM") which would increase the base charge for energy incorporated into customer billings to $0.0990/kWh effective August 1, 2010, and $0.0900/kWh effective April 1, 2011;
3. MECL file an updated report of ECAM rebasing with the Commission by November 30, 2010;
4. A continuation of the Point Lepreau replacement energy deferral and the approval of a 25-year amortization of these deferred replacement energy costs beginning with the return to service expected to be March 1, 2011; and
5. A maximum allowed Return on Average Common Equity of 9.75 per cent for 2010 and 2011.

[18] Under this proposal the Costs Recoverable from Customers (Post 2003) or ECAM balance, excluding Point Lepreau is forecast to be $7,758,500 at the end of 2010 and $12,467,600 at the end of 2011. The Point Lepreau replacement energy costs to be recovered from customers, assuming a 25-year amortization beginning March 2011, would be $43,294,100 at the end of 2010 and $45,999,800 at the end of 2011. A Commission decision on the recovery of Point Lepreau replacement energy is requested in this amended application as well.

[19] The amended application states there is no change requested in the monthly service charge for the various rate categories. The energy rate for electricity is proposed to increase from $0.1178 kWh for the first 2,000 kWh/month and $0.0914 kWh for the remaining monthly consumption to $0.1455 kWh for the first 2,000 kWh/month and $0.1103 for the remaining monthly consumption. The amended application maintains the same pricing relationship between the second and first block rate.

[20] The amended application, as proposed, would see the residential consumer using 650 kWh/month (or 7,800 kWh/year) experience a forecast annual electricity cost reduction of (1.1%) in 2010 and no change in 2011 electricity costs over 2010.

[21] In addition, the amended application states the Revenue Requirement Recovery associated with the second block reinstatement would be allocated across all rate classes and adjustments would be made to the ECAM.

# 3. Discussion

## 3.1 Intervener—PEI Seniors Citizens' Federation

[22] The PEI Senior Citizens' Federation ("Seniors' Federation") presented information concerning demographics of PEI seniors, the economic situations many face in household budgets, and the increasing electricity cost component which reduces available funds for other essential expenditures such as food and shelter.

[23] The Seniors' Federation explained to the Commission seniors' energy needs and the difficulties many face to achieve energy conservation.

[24] The Seniors' Federation raised the following financial issues with the Commission:

- It supports Maritime Electric's objective to reduce customer debt;
- The chosen solution of increasing the basic rates by 15% for 2010 and a further 3% in 2011 is not endorsed;
- The majority of energy supply costs are declining—future customer rates should be declining too;
- NB Power set energy purchase prices but customer rates are also dependent on Maritime Electric's operating costs;
- Increased scrutiny of Maritime Electric's operating costs is required;
- Maritime Electric continues to request high annual capital expenditures and a high rate of return in a non-growth, low risk business activity; and
- Detailed future year estimates are difficult to reason/check by public observers and customers.

[25] The Seniors' Federation notes that the basic electricity rate increase applies to all rate tariff categories affecting every PEI resident, farmer and business, and is independent of the second block issue. It also notes that Maritime Electric is accumulating high customer debt during the Point Lepreau refurbishment and future nuclear power will cost significantly more. In addition, despite a static PEI energy demand situation and a Canadian economy battling with decline, Maritime Electric proposes increasing annual profits from $11.4 Million in 2009 to $12 Million in 2010 and $12.6 Million in 2011.

[26] The Seniors' Federation expressed concern over the Point Lepreau refurbishment project, the continued delays and the mounting cost of replacement energy which must be recovered from customers over future years. They believe this recovery through rates, along with the unknown future price of electricity from the nuclear generator, may make this an expensive energy source.

[27] In addition, concern was expressed about the cost of power from the NB Power Dalhousie generating facility which has increased substantially due to fuel costs, and the future plans for the plant appear to be uncertain based on public comments from NB Power.

[28] The Seniors' Federation made the following recommendations to the Commission:

- 2010 rates remain unchanged with the ECAM amortization period reduced to 8 months to contain customer debt to the Company;
- Return on Equity of 8% is suggested which better reflects the operational risks of the Company;
- A reduction in capital budget to 8% of revenue to a maximum of $15 Million;
- Have external consultants review general and administrative expenses and generation asset costs;
- Key Performance Indicators (KPIs) should be set to competitive benchmarks;
- Review viability of future participation in Point Lepreau considering the energy replacement costs, along with future energy costs from this source;
- Direct the Company to consider terminating its agreement with the Dalhousie generating facility; and
- Future rate applications be single year to enable timely rate changes each April.

[29] In response to Commission staff questioning during the hearing, the Seniors' Federation stated they took no position on the elimination of the second block even though many seniors are affected by this rate differential.

## 3.2 Intervener—John te Raa

[30] Mr. John te Raa presented evidence to the Commission concerning electric heating, its implications to the Company and to customers and rates. Electric heating results in a poor system load factor, an indicator of the efficiency usage of the electrical system. The higher the system electrical load factor the more efficient the use of the system and the less customer cross-subsidization of rates. For instance, Mr. te Raa provided evidence which states the electric load factor of an oil heat customer is 64% while that of an electric heat customer is 30%. The Company's data, provided through interrogatories, supports his claim that electric heat is having a greater influence on PEI with last year's peak load almost shifting to January from December.

[31] Mr. te Raa challenged the intervention by the Province of PEI which supported the retention of the second block. In general, Mr. te Raa states the Province is intervening to protect a small number of customers (7%) at the expense (subsidization) of the majority of customers. In fact, Mr. te Raa states low consumption customers, such as low income customers or families on social services, pay higher electricity bills to offset the discount provided to higher consumption customers.

[32] Mr. te Raa presented a proposal which would alter the current fee structure so that higher energy usage customers would pay a higher base service charge as a consequence of their impact on the system load factor and capacity requirements during peak energy consumption periods. Mr. te Raa stated the Commission should order the Company to create different rate classes within the Residential Rate category as well as set up a different rate class for electric heat customers, including those heating by heat pumps.

[33] Mr. te Raa also stated the ECAM's objective is the smoothing of rates within a set time frame and currently the ECAM just continues to grow and defer the real cost of energy to customers while delaying the proper customer price signals in rates. The ECAM rebasing in both the original application and the amended application shows a growing ECAM deferral account and is not operating as a rate smoothing mechanism.

## 3.3 Intervener—ECO PEI

[34] ECO PEI recommended the implementation of time-of-use rates and suggested the initiative to replace mechanical meters with digital meters should have taken advantage of the upgrade to install Smart meters. Smart meters could be utilized in a variety of environmentally friendly initiatives which ECO PEI believes have a direct benefit to customers. ECO PEI suggests the utility become more involved in fostering future electrical energy options which result in greater use of wind resources to heat our homes, such as wind/electric thermal storage. Transportation was suggested as a key focus for reducing Green House Gas ("GHG") emissions on the Island. While other GHG emissions on the Island have decreased, emissions from transportation have increased. ECOPEI suggested greater utilization of Grid Enabled Vehicles and noted the absence of recharge stations for electric vehicles.

[35] ECO PEI presented a variety of energy conservation and demand side management initiatives and themes which looked at consumer energy usage strategically over the longer term. Although their presentation did not focus on the specifics of this application, ECO PEI would like further development of smart grid and greater inter-regional cooperation in the Maritimes which would assist in the development and usage of the PEI's excellent wind resource.

## 3.4 Intervener—Government of PEI

[36] The Government of PEI, as represented by the Minister of Environment, Energy and Forestry, presented the evidence and expert testimony of Laurence Booth, Professor of Finance, Rotman School of Management, University of Toronto. Mr. Booth has extensive experience in financial affairs and has appeared before many regulatory boards providing evidence relating to Return on Equity ("ROE") for Canadian utilities.

[37] Mr. Booth informed the Commission the objective of rate of return regulation can be summarized as the "fair return standard" which has received wide acceptance due to the legal precedent established in the 1929 case *Northwestern Utilities* v *City of Edmonton*. Mr. Justice Lamont's definition of fair rate of return states:

> "...that the company will be allowed as large a return on the capital invested in the enterprise 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."

[38] Economists, generally, refer to this principle as the opportunity cost and it is generally agreed that the return is applied to the book value of assets.

[39] Mr. Booth stated that most regulators in Canada have adopted an ROE formula approach in which Capital Asset Pricing Model ("CAPM") has been the predominant model used. The model is referred to as a risk positioning model and it tries to estimate a fair return being the risk free rate, plus a risk premium for the market and the company.

[40] Mr. Booth stated that utility stocks did not fair badly during the recent financial market declines and have since regained their pre-market crisis values. This is evidence of their low risk and the fair return approved by regulators using this formula CAPM approach.

[41] Mr. Booth stated the returns of US utilities are not comparable as these utilities are inherently riskier because the business climate in the US is generally riskier. This is evidenced by the financial crisis which originated in the US and the continued perilous economy there. He believes the Canadian economic climate is much healthier in that the recession is felt to be behind us and that Canadian government finances are much healthier than the structural deficit problems faced by the US government.

[42] Mr. Booth stated that in 2009 regulators have reviewed the formula results and made formula risk premium adjustments to take into consideration the financial crisis of 2009. This has resulted in 2009 ROE decisions by regulators being artificially high and these should come down as the financial markets regain liquidity and stability.

[43] Mr. Booth describes the Company as a small distribution utility with a low risk profile, as it is a monopoly provider on PEI, which is a low risk environment due to no significant exposure to a single resource like Newfoundland. Mr. Booth quotes an excerpt of the Standard & Poor's assessment of the Company, "strong business profile ... a mature, but stable economy with relatively low growth rates." Mr. Booth makes reference to the weakness of the Company being its small size, limited market access and significant deferrals. Mr. Booth dismisses the deferrals due to regulators ensuring their collection.

[44] Overall, Mr. Booth assesses the Company as a low risk Canadian utility, even though it has a corporate rating of BBB+, its secured debt is rated at A-. He indicates these ratings are below the averages for Canadian utilities.

[45] Mr. Booth recommends an ROE of 8.0% at the 40% legislated common equity ratio. In addition, he believes the legislated common equity ratio should be revisited once the financial markets have settled from the financial crisis of 2008/09.

[46] Mr. Wayne MacQuarrie, presented the PEI Government's position regarding the retention of the 2nd block reduced rate. In his affidavit, Mr. MacQuarrie stated the Government initially supported the elimination of the second block in 2008. However, due to changed circumstances, Government now feels the second block should be retained until various issues associated with electricity on PEI are resolved.

[47] Mr. MacQuarrie updated the Commission regarding ongoing Government negotiations for less expensive energy supply from other jurisdictions such as Quebec and Newfoundland. These suppliers are becoming viable options for PEI with the Open Access Transmission Tariff ("OATT") approved by many jurisdictions, and the development of a competitive energy supply market.

[48] Mr. MacQuarrie stated that the staged increase in the threshold for 2nd block qualification has improved price signals to consumers and the remaining consumers affected by the 2,000 kWh threshold have few viable options to reduce energy consumption. In addition, the retention of the second block at the current level will not result in a material change in consumer consumption or financial consequence to all ratepayers.

[49] Mr. MacQuarrie stated the Point Lepreau refurbishment and replacement energy expense and the uncertainty associated with the Dalhousie generating facility will have further rate burden on consumers and will impact energy consumption decisions.

## 3.5 Members of the Public

[50] Each of the three groups that attended and made presentations at the hearing expressed concern over electricity rates on PEI and their inability to recover these rising costs from the market place. In addition, each group expressed frustration over the Commission's previous decision to eliminate 2nd block reduced rate pricing. The farm groups stated that energy conservation and demand side management programs have been incorporated in their daily activities but farming operations require significant electricity consumption. Many government programs, which provide assistance for capital outlays to reduce farm energy bills, do not provide the appropriate cost benefit relationship to warrant investment. For instance, on-farm wind generated electricity requires changes in government electricity regulations to allow for net billing. It is believed net billing would provide a stronger business case as it results in a faster payback.

## 3.6 Applicant—Maritime Electric Company, Limited

[51] Maritime Electric presented evidence and expert testimony of Kathleen McShane, President of Foster & Associates, an economic consulting firm. Ms. McShane reiterated the fair return standard as the legal precedent upon which regulators must establish ROE amounts. Ms. McShane states the fair return standard gives a regulated utility the opportunity to:

- earn a return on investment commensurate with that of comparable risk enterprises;
- maintain its financial integrity; and
- attract capital on reasonable terms.

[52] Ms. McShane presented a view that Maritime Electric faces higher business risk than the average Canadian utility. This assessment referenced the following risk factors:

- Maritime Electric faces higher operating and supply risks relative to the typical Canadian distribution utility. An Island location dependent upon submarine cables and the requirement to maintain on-Island generation represents risks no other Canadian distribution utilities face in regards to supply disruption;
- PEI's *Renewable Energy Act* requires the Company to source 15% of its energy requirements from renewable sources with an increase to 30% contemplated, and significant penalties for non-compliance;
- Maritime Electric's small size and its limited potential for growth in serving a largely rural population with low-growth rates puts pressure on the aging infrastructure and upward pressure on rates;
- Regulatory risk for the Company has been a factor in the past noting the changed regulatory model to price cap regulation and then back to cost-of-service regulation;
- Maritime Electric continues to maintain significant deferral accounts for energy purchases for both ongoing energy supply and replacement of Point Lepreau energy due to the refurbishment. These deferral accounts require regulatory approvals for recovery and put pressure on the Company's financial position as evidenced by the operating financial ratios;
- Maritime Electric's corporate credit rating of BBB+ is lower than that of the average Canadian electric utility (A-) and the Standard & Poor's rating has noted the Company's poorer business metrics, such as lower than average earning before taxes interest coverage, funds from operation to total debt and challenged cash flow position; and
- Overall, Standard & Poor's have rated Maritime Electric's business risk profile as "Satisfactory" which is two rating categories below the average business risk profile assigned to Canadian utilities of "Excellent".

[53] Ms. McShane concluded the ROE of 9.75% on a common equity ratio of between 41% and 41.8% is not only reasonable but relatively low, based on approved ROE levels for other Canadian and US utilities.

[54] Ms. McShane acknowledged the role of formulas in ROE rate setting, however, she pointed to shortcomings in the formula approach in that measuring individual securities risk relative to the market is by a beta factor. Selecting a beta factor that appropriately measures security risk requires judgment that can lead to disagreement among evaluators. Ms. McShane suggested no one formula can measure all requirements of the fair return standard and pinpoint a fair return. In establishing a fair return, reliance on multiple tests, such as, CAPM, discounted cash flow and comparable earnings tests, is a better approach. Each test requires judgment in their application.

[55] Ms. McShane stated that this Commission has never adopted the CAPM formula as the means of ROE. Ms. McShane also stated the Commission has previously taken into consideration comparable earnings of other Atlantic Canadian electric utilities in setting ROE.

[56] Ms. McShane agreed that certain Canadian regulators have incorporated premiums in ROE to account for the impact of the financial crisis. Ms. McShane argued that the financial crisis has highlighted the flaw of the automatic formula approach as the formulas do not take into account all business risks in a timely fashion.

[57] Ms. McShane provided a table of approved ROE and common equity ratios for 2009. This table also provided US average ROE as well. The table outlines the 2009 average Canadian ROE of 9.52% with a common equity ratio of 40.5%. This includes the 9.85% ROE for Ontario Electricity Distributors for 2010. This 2010 OEB decision is 0.10% higher than the 2009 rate of 9.75%.

[58] In support of the written evidence filed as part of the application, Maritime Electric provided testimony from Company President, Mr. Fred O'Brien and a panel of members of Senior Management, consisting of: Mr. William Geldert, Mr. John Gaudet and Mr. Steve Loggie.

[59] Maritime Electric provided the Commission with a supplemental affidavit in support of retaining the second block in its current form for the following reasons:

- It may be premature due to ongoing discussions between the Governments of Quebec and PEI concerning a power purchase agreement which would reduce energy costs and could affect decisions concerning the elimination of the second block;

- Current DSM initiatives have been successful and the retention of the 2nd block will not have a material impact upon future Company DSM plans; and
- The retention of the second block does not cause material differences in the financial situation of the Company as the Revenue Requirement Recovery or revenue shortfall from the 2nd block will be spread across all rate classes, and these differences are not material.

[60] In addition, in response to comments raised during the hearing on the issue of net billing, the Company expressed concerns relating to cross-subsidization of ratepayers under net billing approaches.

[61] The Commission acknowledges and thanks all of the participants for their contributions.

# 4. Findings

[62] Upon completion of the public hearing and a review of the evidence and closing submissions of the parties, the Commission made the following determinations:

## 4.1 Point LePreau Replacement Energy

[63] The Company has a 4.72% participation agreement with NB Power Nuclear which entitles the Company to this portion of energy output from the facility. During the hearing the Commission heard the Company had little influence on the refurbishment decision due to its minor involvement with the facility. The 1994 participation agreement established the requirement to pay the monthly fixed overhead costs of the facility during refurbishment, as well as obtain replacement energy.

[64] During the hearing, the Company stated that future participation in Point Lepreau is more beneficial than trying to buy out its participation agreement responsibilities. The Company stated the Lepreau generating facility is still economically viable, in their opinion.

[65] Maritime Electric stated NB Power has not made any decisions regarding the customer rate recovery of replacement energy costs. While Maritime Electric is deferring the replacement energy costs it continues to make monthly payments to NB Power for its share of the operating and maintenance costs.

[66] At present, the refurbishment of Point LePreau is not complete and there have been several delays. The expected date of return to service is now scheduled as March 1, 2011; however, further delays are possible.

[67] The Commission heard the concerns expressed by both the Seniors' Federation and Mr. te Raa regarding the increasing deferred replacement energy costs. Effective January 1, 2009, and continuing to the return to service date of Point Lepreau, the Commission directed the deferral of replacement energy costs. The Company's application states the 2010 year-end balance of replacement energy costs are forecast to be $43.3 million and $46.0 million in 2011. This assumes a return to service of March 1, 2011 and the beginning of the 25-year amortization period requested in this application.

[68] The Commission has considered the information filed with the application concerning the amortization of replacement energy costs of other jurisdictions and notes that it is accepted regulatory practice to amortize costs over the future service life of the refurbished facility.

[69] The Commission, therefore, orders the Company to continue with the deferral of the replacement energy costs until the return to service of the Point Lepreau facility. The Commission further orders the Company to begin recovering replacement energy costs through rates over the expected future service life of the facility, currently estimated to be 25 years. The Commission directs the Company to provide updated information concerning the expected future service life once reliable estimates are established.

[70] The Commission is concerned over the lack of detailed evidence associated with the Point Lepreau facility. The Commission directs Maritime Electric to file, on a confidential basis, the cost estimates and economic analysis associated with their continued involvement with the facility.

## 4.2 ECAM Rebasing and Amortization Period

[71] The Company has filed the ECAM rebasing proposal contained in this application pursuant to Commission Order UE09-02. The Company's ECAM balances in the original application and amended application are forecast as follows:

| | Calendar Year | ECAM Year End Balance |
|---|---|---|
| Original Application | 2010 | $6,122,255 |
| | 2011 | $8,600,141 |
| Amended Application (retain 2nd block) | 2010 | $7,758,524 |
| | 2011 | $12,467,603 |

[72] The original application and supplemental amended application (retain 2nd block) contained ECAM rebasing proposals that had the following annual customer cost impact:

| | | | 2010 | | 2011 | |
|---|---|---|---|---|---|---|
| Rate Class | Demand KW/Month | Consumption kWh/Month | Original Application Apr 1 | Amended (Retain 2nd Block) Aug 1 | Original Application Apr 1 | Amended (Retain 2nd Block) Aug 1 |
| Residential - Rural | n/a | 650 | -0.5% | -1.1% | -0.4% | 0.0% |
| General Service | 0-20 | 500 | 2.1% | 2.7% | 0.5% | 0.8% |
| General Service | 30 | 3,000 | 2.1% | 2.7% | 0.5% | 0.8% |
| General Service | 50 | 5,000 | 2.2% | 2.7% | 0.4% | 0.7% |
| General Service | 250 | 250,000 | -2.7% | -2.1% | -1.6% | -1.3% |
| Large Industrial | 9,000 | 9,000,000 | -9.3% | -9.0% | -5.3% | -4.9% |
| Small Industrial | 50 | 5,000 | 2.0% | 2.6% | 0.3% | 0.6% |
| Small Industrial | 150 | 25,000 | 0.0% | 0.5% | -0.5% | -0.2% |
| Small Industrial | 500 | 300,000 | -4.5% | -3.9% | -2.6% | -2.2% |

[73] The amended application, with the retention of the 2nd block, incorporates an ECAM base energy charge of $0.0990/kWh effective August 1, 2010 and $0.0900kWh effective April 1, 2011.

[74] The Commission shares the concerns over the extent of deferrals for both replacement energy and normal energy supply. Interveners noted that in the amended application the Company ended up increasing the deferred energy charges. The Commission notes that, in addition to increasing the deferrals, the annual customer cost impact increased only slightly with the final result for 2011 being rural residential customers seeing no change in annual cost of electricity.

[75] In response to intervener and Commission questions, the Company stated their desire to eliminate deferred energy accounts and recover all costs from customers sooner. However, the Company stated their additional concern regarding the cost impact to customers. The Company's amended application was an attempt to balance the Company's interests, as well as the cost to customers, while maintaining the second block.

[76] The Commission is concerned by the mixed signals sent to all parties in the amended application. The base ECAM rate would be set at a rate that results in the deferred ECAM account increasing in value. This places further burden on future ratepayers who will ultimately cover these costs.

[77] Most interveners agreed that energy charges should reflect the true supply cost of energy and this would send the appropriate price signals to consumers regarding energy choices. In addition, the Commission heard that the overall cost of energy is important to seniors and this group wants an indication that energy rates are stabilizing. A reducing ECAM deferral balance is a step in that direction.

[78] The Commission has reviewed various ECAM rate scenarios and orders that the new base rate for ECAM be set at $0.0970kWh effective August 1, 2010 and that an additional $0.006kWh be added to the ECAM base rate for the period August 1, 2010 to December 31, 2010. This additional rate allows for recovery of energy costs associated with the delay in the rate application from the initially requested April 1, 2010 implementation date to the August 1, 2010 actual implementation date.

[79] The new ECAM base rate is forecast to result in year-end ECAM deferral account balances of $6,046,954 for 2010 and $5,709,184 for 2011. These balances are lower than both the original and amended applications. The new ECAM base rate will result in a year-over-year annual rural residential cost change of -0.2% in 2010 and 1.1% in 2011, assuming exchange rates and energy supply costs remain consistent with 2010 levels. The Commission considers this an appropriate rate change to achieve reduced deferrals.

[80] The Commission has considered the request from the Seniors' Federation to reduce the ECAM amortization period and increase the collection of deferred energy supply costs. The Seniors' Federation views this as more desirable than an increase in base rates as it would permit the rates to easily reduce if energy supply costs decrease. The Commission has considered this option and notes that the ECAM at one time was set at eight months; however, feels it is more important to have the ECAM base rate set at a level close to the actual energy supply costs, so that deferred energy costs are minimal into the future. Both the ECAM and the base rates are subject to regulatory control and can be adjusted to reflect reduced energy costs. Therefore, the Commission directs the Company to continue the 12-month amortization in the ECAM formula.

## 4.3 2nd Block Tariff and Rate Design

[81] The Company filed a supplemental affidavit amending the original application and requesting reconsideration of Commission Order UE08-01. This Order approved the elimination of the second block rate over a three-year period. Although the Company is not financially impacted by the second block

elimination, Maritime Electric stated that the circumstances regarding energy negotiations and their potential implications to the overall rate tariff, as well as progress on demand side management programs support the request for reconsideration.

[82] The Commission heard from farm groups concerning the financial impact of this rate elimination. These groups discussed their limited ability to reduce energy consumption within existing demand side management tools. In addition, current government programs, designed to financially assist farms install on-farm renewable generation, fall short in making a sound business case for the investment. Farm groups suggested that legislation and regulation changes are required by Government to improve the attractiveness of on-farm renewable energy infrastructure.

[83] The Commission was informed of the peculiarities which exist in the current rate tariff schedule. The current tariff schedule was forced on the Company with the legislated price cap regulation of 1994. For instance, within the residential rural tariff (and 2nd block discount) the following are some organizations which qualify:

- small and large scale farm organizations ,
- fish farms,
- campgrounds and trailer parks,
- hotels, motels and tourist courts,
- credit unions, and
- services incidental to fishing and farming.

[84] The Commission was informed by Company officials during the hearing that the tariff schedule which existed prior to 1994 was completely different with consideration given to the volume and nature of electricity usage. For instance, rate differences existed between 100 amp and 200 amp service.

[85] The Commission heard from Mr. John te Raa concerning the system efficiency implications of electric heat and apparent cross-subsidization of rates and charges between low- and high-energy usage customers. Mr. te Raa states the 2nd block tariff furthers this inequity. Mr. te Raa directed the Commission to the results of the 2008 *Cost of Service Study* filed as a response to a Government of PEI interrogatory in this application. This study highlights inequities between rate classes within the current tariff structure.

[86] During the hearing, Company officials acknowledged the results of the 2008 *Cost of Service Study* and advised the Commission that to consider the 2nd block rate issue in isolation of the other obvious inequities in the overall tariff structure would be unreasonable and unfair to all customers.

[87] The Commission noted Company comments which stated that a new cost of service study and a rate design proposal with a goal of tariff fairness within ranges is required.

[88] The Commission notes the preamble to the *Electric Power Act* which states: "*Whereas the rates, tolls and charges for electric power should be reasonable, publicly justifiable and not discriminatory*".

[89] This preamble instructs the Commission to ensure fairness within rate categories and that rates must be based on the cost of providing this service. That means rates do not take into consideration the characteristics of the customer such as farming, fishing, home heat or industrial usage. Rates developed with a rate design objective of fairness based on cost of service are the requirements of the legislation.

[90] The Commission appreciates that the farm community has faced significant economic challenges, but that fact alone does not permit the Commission to vary rates to assist that industry. In order to achieve rate fairness, rates must be based on the cost of providing service to a customer or class of customers.

[91] In true cost of service terms, the Commission was not presented with evidence that warrants retention of the declining 2nd block rate. However, evidence was heard that the residential rate class itself is seriously flawed. Adopted in 1994 from the NB Power rate structure, this rate structure is out of date.

[92] The Commission accepts the argument that any further changes to rate tariffs should await the outcome of a new rate design proposal based on a full cost of service study.

[93] Therefore, the Commission will defer the decision on the removal of the 2nd block tariff until a rate design proposal is approved by the Commission. The Commission orders the Company to prepare a complete rate design proposal with all the necessary supporting reports. The Commission has heard evidence that a new rate design process could result in some significant rate changes, both increases and decreases, for customers. Upon completion of the cost of service and rate design process, the Company is encouraged to engage in stakeholder consultations which explain the process and gain input on the proposed rate classifications. The rate design proposal will incorporate recommendations on the current 2nd block and any other potential rate additions or deletions. Further, the Commission directs that the impact of the increased use of electric heat on the system service requirements be separately considered and addressed in the rate design process.

[94] The rate design proposal must be filed with the Commission by December 31, 2011. This date provides time for the conclusion of inter-governmental power purchase agreement negotiations.

## 4.5 Rate of Return

[95] Maritime Electric is requesting approval of a 9.75% return on average common equity. Maritime Electric states that it faces higher business risk than other Atlantic Canada investor-owned electric utilities as it operates on a small island with an undiversified economy. The inability to spread risk throughout a diversified customer base means investors are more cautious on the outlook for Maritime Electric. The Company states this is evidenced by the Standard and Poor's BBB+ credit rating which indicates a stable outlook, but this rating is lower than other investor-owned utilities such as Emera's, Nova Scotia Power, and Newfoundland Power. In fact, Maritime Electric notes Standard and Poor's expressed concern about Maritime Electric's relatively poor cash flow position which is caused by the ECAM and delayed recovery of energy costs. The bond raters expressed concern about the relatively low earnings as a percentage of debt ("Interest Coverage Ratio").

[96] Section 24(1) of the *Electric Power Act* states return on investment shall be set by the Commission and reads as follows:

| | |
|---|---|
| Return on investment, utility authorized to earn certain, computation of | 24. (1) Every public utility shall be entitled to earn annually such return as the Commission considers just and reasonable, computed by using the rate base as fixed and determined by the Commission for each type of service furnished, rendered or supplied by such public utility, and the return shall be in addition to the expenses as the Commission may allow as reasonable and prudent and properly chargeable to operating account, and to all just allowances made by the Commission according to this Act and the rules and regulations made by the Commission hereunder. |

[97] The Commission heard from expert witnesses who stated the principles of the fair return standard. In essence, a fair return is met if a utility can attract capital on reasonable terms, can maintain its financial integrity, and the return allowed is consistent with returns of businesses with similar risks. That standard was first established in Canada with the 1929 case, *Northwest Utilities v. Edmonton (City).*

[98] The Commission noted Mr. Booth's comments in which he stated the 2009 approved ROE was adjusted higher to take into consideration the 2008-2009 financial crisis. In fact, Mr. Booth suggested the Cost of Capital Review, by the Ontario Energy Board (OEB), was a consequence of the financial crisis. The Commission noted this decision was made after the economic financial problems and reflects the improved Canadian economy.

[99] The Commission noted testimony from both experts with different opinions regarding the risk profile of Maritime Electric in comparison to the Ontario distribution utilities. The Commission accepts that Maritime Electric, with its responsibilities for electricity supply, is different than Ontario electric distribution utilities. The Commission views this difference as significant.

[100] The Commission notes the lower than average Company corporate rating prepared by Standard & Poor's and the debt rating of BBB+, both lower than Canadian averages, is further evidence that the risk profile of Maritime Electric is higher.

[101] The Commission notes the 2009 Nova Scotia Power ROE, arising from a negotiated settlement agreement, of 9.35% on a common equity ratio of 37.5%. In addition, the Newfoundland Power ROE of 9.0% with a common equity ratio of 45% was approved for 2010.

[102] The Commission also notes decisions from the British Colombia Utilities Commission ("BCUC") regarding the ROE rates allowable for a benchmark utility (9.5%), Terasen Gas. In addition, as pointed out by Ms. McShane in her evidence, the BCUC decision stated:

> "The Commission Panel notes that CAPM is based on a theory that can neither be proved nor disproved, relies on a market risk premium which looks back over nine decades and depends on a relative risk factor of beta. The fact that the calculated beta for PNG (considered by Dr. Booth to be the most risky utility in Canada) was 0.26 in 2008 causes the Commission Panel to consider that betas conventionally calculated with reference to the S&P/TSX are distorted and require adjustment. The Commission Panel will give weight to the CAPM approach, but considers that the relative risk factor should be adjusted in a manner consistent with the practice generally followed by analysts so that it yields a result that accords with common sense and is not patently adsorb."

[103] The Commission finds this commentary particularly relevant. The Commission did not adopt a formula approach to ROE during a period of time when such an approach was used by regulators as the standard for setting ROE. The Commission sees little value in placing greater emphasis on a formula approach at a time when that approach is either being abandoned, altered or deviated. Judgement, taking into consideration comparators, current market conditions, and appropriate risk assessment, are also very relevant.

[104] The Commission notes the BCUC ROE decision for FortisBC of 9.75%, which is 0.25% above the benchmark BC ROE rate. This Commission views Maritime Electric as a higher risk than the benchmark BC utility and FortisBC due to a variety of factors such as utility size, nature of operations, economic climate within which it operates, and regulatory risk factors.

[105] Taking into consideration all the ROE evidence presented, the Commission finds an ROE of 9.75% to be fair and reasonable considering the risk factors of Maritime Electric, the allowed ROE of comparable regional and national jurisdictions, and the corporate business and debt ratings of Maritime Electric.

## 4.4 Revenue Requirement and Other Matters

[106] The rates of a public utility are designed to generate, in a fiscal year, what is known as the revenue requirement. The revenue requirement is the sum of all operating expenses, amortization or depreciation of capital assets, interest on debt, income tax and return on equity. Under traditional rate regulation, the revenue requirement approval is required to establish customer rates.

[107] With the establishment and approval of the ECAM approach to rate setting, the energy cost component of the revenue requirement is essentially established each month as the energy rates are set based on actual costs incurred by the company, plus or minus the net ECAM adjustment. The Commission assesses the Company's due diligence in obtaining the best price for energy supply. During the 2009 rate case, the evidence of Mr. Terry MacDonald, who reviewed the current Energy Purchase Agreements and provided energy pricing advice to the Commission, supports this information. As these same agreements are in place until March 2011, the Commission, therefore, accepts the energy supply costs of the Company as reasonable until that time.

[108] The remaining costs comprising the revenue requirement are assessed by the Commission for reasonableness. The *Electric Power Act* provides guidance to the Commission in Section 21(3) which reads:

| | |
|---|---|
| Rate base, determination and fixing for each utility | 21. (1) The Commission may . . .<br><br>(3) (a) include all or any of<br>(i) an allowance for necessary working capital, and<br>(ii) any other fair and reasonable expenditure which the Commission thinks proper and basic to the public utility's operation; |

[109] Expenditures of Maritime Electric are reviewed by the Commission monthly along with rate schedules. In addition, the rate application includes details of annual expenditure plans. The Commission has considered these estimates of expenditures using analysis and comparison of past expenditures and inquiries into proposed plans for future expenditures. In addition, the

public hearing provided an opportunity for further review into the reasonableness of the expenditures.

[110] The Seniors' Federation expressed concern about the oversight of Company operations and expenses in both the generation, general and administrative areas. In addition, they stated the current Key Performance Indicator ("KPI") monitoring tool employed by the Commission lacked credibility in that no external comparators are considered. The Commission acknowledges the shortcomings of the KPI measurement tool but views the process as valuable. The Commission notes there must be caution exercised in comparing organizations both within the utility sector and general business community. Considerable judgment must be exercised in the KPI review process. The Commission is involved in the process of benchmarking evaluation techniques, an issue currently being debated within the regulatory community across Canada.

[111] The Commission understands the concerns raised by the Seniors' Federation regarding Commission oversight of Company management and operations. While not always highly visible, this is a constant function of the Commission and a consideration woven into all interactions between the regulator and the utility. In addition, external expertise and consultants are employed from time to time to assist the Commission in this regard.

[112] Recent engagements by the Commission include: propriety of general and administrative expenses; assessment of power purchase contracts; demand side management plans; open access transmission tariff requirements, and the health and safety impacts of transmission lines.

[113] The Commission endeavors to make all such assessments available to the public, however, given the confidential nature of some matters, not all reviews are made public.

[114] The Commission, in its duty to ratepayers, must also be mindful of the costs of employing such expertise and satisfy itself that there is value to the Commission and ratepayers in such expenditures. The Commission, through normal regulatory processes, also affords the opportunity for interested parties to pose questions and raise concerns.

[115] The Seniors' Federation expressed concern about the value of Company capital expenditures and the implications for rates. All capital expenditures are approved by the Commission through a public process. The Company is required to provide detailed explanations for all proposed capital expenditures. The Commission not only questions company proposed initiatives, but also considers matters that should be explored. For example, following the Hurricane Juan damage in Nova Scotia, the Company was instructed to prepare and file a Contingency Readiness and Emergency Response Plan which covers a variety of contingencies such as submarine cable failures, transmission tower system failures, Emergency Response Plans and an Infrastructure Readiness Report. This initiative proved valuable when the 2008 ice storms caused considerable damage to transmission and distribution systems.

[116] The Seniors' Federation suggested a capital budget of 8 to 12% of revenue to a maximum of $15 Million, which would have the impact of reducing capital expenditures by $7 Million this year. The Commission places high value on system reliability and is concerned an artificial cap on capital expenditures might jeopardize necessary capital upgrades. Given the scrutiny of capital budgets and the necessary approval process, the Commission is not prepared to endorse such a cap.

[117] The Commission considers its website a valuable tool for providing information to the public and will continue to post relevant information to the site. The Commission will continue with the current capital budget approval process.

# 5. Disposition

[118] An Order will therefore issue implementing the findings and conclusions contained in these reasons.

# IN THE MATTER of an application by Maritime Electric Company, Limited for approval of amendments to rates, tolls and charges.

# Order

**UPON** receiving an application by Maritime Electric Company, Limited for approval of proposed amendments to its rates, tolls and charges;

**AND UPON** receiving a supplemental affidavit amending the original application to request reconsideration of the elimination of the 2nd block tariff;

**AND UPON** reviewing the additional evidence received in response to staff interrogatories and intervener interrogatories;

**AND UPON** reviewing and taking into consideration the evidence provided during the hearing by interveners and expert witnesses;

**AND UPON** review of previous Commission Orders concerning the Energy Cost Adjustment Mechanism (ECAM), Rate of Return, Point Lepreau replacement energy and 2nd block tariff elimination;

**NOW THEREFORE**, for the reasons given in the annexed Reasons for Order;

## IT IS ORDERED THAT:

1. the Company shall continue deferral of Point Lepreau replacement energy costs until its return to service at which time the Company will begin amortization of this cost,

through the ECAM account, over the future expected service life of the refurbished facility;

2. the Company shall file a business case analysis associated with its continued involvement for both Point Lepreau and Dalhousie generating facilities;

3. the Company shall rebase the base rate of energy effective with meter readings taken on and after August 1, 2010 as follows:

| | August 1, 2010 | Additional Rate August 1, 2010 to December 31, 2010 |
|---|---|---|
| ECAM Base Rate ($/kWh) | 0.0970 | 0.006 |

4. the Company shall continue with a 12-month amortization period in the ECAM formula;

5. the maximum allowed return on average common equity is set at 9.75% for 2010 and 2011; and

6. the Company shall retain the 2,000 kWh second block reduced rate and include consideration of this issue in a rate design proposal to be filed with the Commission by December 31, 2011.

DATED at Charlottetown, Prince Edward Island, this 12th day of July, 2010.

# BY THE COMMISSION:

Sgd) *Maurice Rodgerson*

Maurice Rodgerson, Chair

(Sgd) *John Broderick*

John Broderick, Commissioner

(Sgd) *Anne Petley*

Anne Petley, Commissioner

(Sgd) *Ernest Arsenault*

Ernest Arsenault, Commissioner

# NOTICE

Section 12 of the ***Island Regulatory and Appeals Commission Act*** reads as follows:

> *12. The Commission may, in its absolute discretion, review, rescind or vary any order or decision made by it, or rehear any application before deciding it.*

Parties to this proceeding seeking a review of the Commission's decision or order in this matter may do so by filing with the Commission, at the earliest date, a written Request for Review, which clearly states the reasons for the review and the nature of the relief sought.

Sections 13.(1), 13(2), 13(3), and 13(4) of the ***Act*** provide as follows:

> *13.(1)An appeal lies from a decision or order of the Commission to the Court of Appeal upon a question of law or jurisdiction.*
>
> *(2) The appeal shall be made by filing a notice of appeal in the Court of Appeal within twenty days after the decision or order appealed from and the rules of court respecting appeals apply with the necessary changes.*
>
> *(3) The Commission shall be deemed to be a party to the appeal.*
>
> *(4) No costs shall be payable by any party to an appeal under this section unless the Court of Appeal, in its discretion, for special reasons, so orders.*

IRAC140A(04/07)

**NOTE**: In accordance with IRAC's *Records Retention and Disposition Schedule*, the material contained in the official file regarding this matter will be retained by the Commission for a period of 5 years.

# DÉCISION

**QUÉBEC** **RÉGIE DE L'ÉNERGIE**

| D-2010-147 | R-3724-2010 | 26 novembre 2010 |
|---|---|---|

**PRÉSENTS :**

Louise Rozon
Richard Carrier
Lise Duquette
Régisseurs

**Gazifère Inc.**
Demanderesse

et

**Intervenants dont les noms apparaissent ci-après**

**Décision relative à la Phase 2 – Taux de rendement – et à la Phase 4 – Plan d'approvisionnement pour l'exercice 2011 et tarifs à compter du 1er janvier 2011**

***Demande relative au renouvellement du mécanisme incitatif, à la fermeture réglementaire des livres pour la période du 1er janvier 2009 au 31 décembre 2009, à l'approbation du plan d'approvisionnement pour l'exercice 2011 et à la modification des tarifs de Gazifère Inc. à compter du 1er janvier 2011***

[1] régulateurs comme fondant la norme du rendement raisonnable, soit les critères de l'investissement comparable, de l'intégrité financière et de l'attraction des capitaux. La norme du rendement raisonnable et les trois critères la fondant n'ont fait l'objet d'aucun débat en la présente instance.

[2] Selon ces trois critères, pour être raisonnable, un taux de rendement sur le capital doit :

- être comparable à celui que rapporterait le capital investi dans une autre entreprise présentant un risque analogue (critère de l'investissement comparable);
- permettre à l'entreprise d'attirer des capitaux additionnels à des conditions raisonnables (critère de l'effet d'attraction de capitaux);
- permettre à l'entreprise réglementée de préserver son intégrité financière (critère de l'intégrité financière).

[3] Dans sa décision D-2009-156, la Régie concluait que ces critères font consensus et qu'ils peuvent servir de guide dans l'exercice de sa juridiction à l'égard de la fixation d'un taux de rendement raisonnable.

[4] Par ailleurs, dans cette même décision, la Régie considérait que son devoir est de déterminer un taux de rendement raisonnable et que la méthode qu'elle utilise relève de sa discrétion. À cet égard, la Régie rappelait que les tribunaux ont reconnu la grande latitude et la discrétion des organismes de régulation dans le choix de la meilleure méthode pour fixer un taux de rendement raisonnable sur l'avoir de l'actionnaire.

## 1.1 MODÈLES UTILISÉS POUR ÉTABLIR LE COÛT DE L'AVOIR PROPRE

[5] Les experts entendus lors de l'audience utilisent des approches et des modèles différents pour recommander un taux de rendement raisonnable sur l'avoir de l'actionnaire pour Gazifère.

[6] L'expert de Gazifère, Mme Kathleen McShane, applique, pour l'évaluation du coût de l'avoir propre, plusieurs modèles de type « prime de risque », dont le modèle d'évaluation des actifs financiers (MÉAF), le modèle d'actualisation des flux monétaires (AFM) avec une et deux variables et enfin, le modèle basé sur l'historique de la prime de risque d'un distributeur repère. Elle termine son exposé avec une estimation du rendement

requis obtenue à l'aide de la méthode directe du modèle AFM en ayant recours à plusieurs variantes.

[7] L'expert de l'ACIG, le D[r] Laurence D. Booth, utilise le MÉAF ainsi qu'un modèle à deux facteurs portant sur la prime de risque du marché et la prime de risque des obligations de long terme du Canada.

[8] Le MÉAF est représenté par l'équation suivante :

$$K = R_f + \beta^*(R_m - R_f)$$

[9] Cette équation représente le taux de rendement (K) qu'un investisseur s'attend à recevoir d'un placement effectué sur un titre comportant un certain risque. Le rendement attendu pour ce titre (K) correspond au rendement qui pourrait être obtenu par un investissement sans risque ($R_f$), auquel est ajoutée une prime de risque. Cette prime, propre au titre évalué, est proportionnelle au risque du marché ($R_m$ - $R_f$). Ce dernier est estimé par la différence entre le rendement généré par un portefeuille de titres diversifié ($R_m$) et celui d'un investissement sans risque ($R_f$). La relation proportionnelle entre le risque du marché et le risque associé au titre est exprimée par le facteur bêta ($\beta$).

[10] Le taux de rendement sur l'avoir de l'actionnaire résultant des calculs du D[r] Booth en vertu des modèles qu'il utilise est de 7,75 %, avant la prise en compte des frais d'émission et de l'ajustement pour le risque de Gazifère. Le D[r] Booth recommande pour Gazifère un taux de rendement autorisé sur l'avoir de l'actionnaire de 8,5 %.

[11] Le taux de rendement sur l'avoir de l'actionnaire résultant des calculs de Mme McShane en vertu du MÉAF est de 9,25 % lors du dépôt de sa preuve et de 8,71 % lors de sa mise à jour à l'audience, avant la prise en compte des frais d'émission et de l'ajustement pour le risque de Gazifère.

[12] Le modèle prime de risque basé sur le modèle AFM selon une ou deux variables (méthode indirecte) vise à estimer la prime de risque des sociétés réglementées à partir d'un échantillon de sociétés américaines. Selon le modèle AFM, le coût de l'avoir propre mensuel est estimé à partir de la somme de deux éléments : d'une part, le consensus des analystes financiers à l'égard des prévisions de croissance normalisée à long terme des profits et, d'autre part, le rendement attendu du dividende. La prime de risque, quant à

elle, est égale à la différence entre la moyenne mensuelle du coût de l'avoir propre de l'échantillon et le rendement à la fin du mois correspondant aux obligations de 30 ans du gouvernement américain[1].

[13] En appliquant le modèle AFM, Mme McShane fait deux régressions linéaires pour ajuster la prime de risque résultant de son estimation. Dans un premier temps, elle utilise le taux de rendement des obligations de 30 ans du gouvernement des États-Unis comme variable explicative. Dans un deuxième temps, elle ajoute une seconde variable explicative correspondant à l'écart de rendement entre les obligations à long terme des sociétés réglementées américaines de cote de crédit A et les obligations de 30 ans du gouvernement des États-Unis.

[14] Le taux de rendement sur l'avoir de l'actionnaire résultant des calculs de Mme McShane en vertu de ce modèle est de 9,40 % lors du dépôt de sa preuve et de 9,10 % lors de sa mise à jour à l'audience, avant la prise en compte des frais d'émission et de l'ajustement pour le risque de Gazifère.

[15] Le modèle basé sur l'historique de la prime de risque des sociétés réglementées se calcule à partir des rendements réalisés des sociétés réglementées canadiennes et américaines. Mme McShane utilise un rendement moyen réalisé de 11,5 % pour ces sociétés réglementées. Par la suite, elle soustrait de ce résultat la prévision à long terme du taux de rendement des obligations de 30 ans du gouvernement du Canada, qui est de 5,25 %. La prime de risque des sociétés réglementées qu'elle en déduit est donc de 6,25 %. Enfin, elle additionne cette prime de risque à sa prévision du taux de rendement des obligations de 30 ans du gouvernement du Canada pour l'année 2011, qu'elle établit à 4,75 %.

[16] Le taux de rendement sur l'avoir de l'actionnaire résultant des calculs de Mme McShane en vertu de ce modèle est de 11 % lors du dépôt de sa preuve et de 10,40 % lors de sa mise à jour à l'audience, avant la prise en compte des frais d'émission et de l'ajustement pour le risque de Gazifère.

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1 Pièce B-1, GI-4, document 1, page 51.

[17] Comme alternative aux méthodes de type « prime de risque », Mme McShane estime de façon directe le rendement attendu à l'aide du modèle AFM. Ce modèle indique que le prix P d'une action est égal à la valeur actualisée au taux k de ses dividendes futurs qui croissent indéfiniment au taux g.

Le modèle AFM s'exprime donc par l'équation :

$$P = D_1/(k-g)$$

ou, écrit d'une autre façon :

$$k = D_1 /P + g$$

où

| | |
|---|---|
| $k =$ | taux de rendement sur l'avoir de l'actionnaire |
| $D_1 =$ | dividende versé à l'année 1 |
| $P =$ | prix au marché de l'action |
| $g =$ | taux de croissance des dividendes |

[18] Le taux de rendement sur l'avoir de l'actionnaire résultant des calculs de Mme McShane en vertu de ce modèle est de 10 % lors du dépôt de sa preuve et est demeuré le même lors de sa mise à jour à l'audience, avant la prise en compte des frais d'émission et de l'ajustement pour le risque de Gazifère.

[19] Mme McShane conclut que, selon les modèles de type « prime de risque » et AFM, le taux de rendement sur l'avoir de l'actionnaire résultant de ses calculs est de 10 % lors du dépôt de sa preuve et de 9,70 % lors de sa mise à jour à l'audience, avant la prise en compte des frais d'émission et de l'ajustement pour le risque de Gazifère.

[20] Mme McShane recommande pour Gazifère un taux de rendement autorisé sur l'avoir de l'actionnaire de 11,25 % lors du dépôt de sa preuve et de 10,95 % lors de sa mise à jour à l'audience.

[21] La Régie s'étonne du résultat produit par le modèle basé sur l'historique de la prime de risque d'un distributeur repère proposé par Mme McShane. En effet, la Régie constate un écart important entre le résultat de 6,25 % pour la prime de risque d'un distributeur repère alors que, dans l'application du MÉAF présenté par l'experte, cette prime est de 4,56 % sur la base d'une prime de risque du marché de 6,25 % et d'un bêta de 0,68.

[22] Toutefois, en audience[2], Mme McShane précise que la Régie doit regarder ces tests individuellement et reconnaître qu'ils apportent une perspective différente de ce que le rendement pourrait être. Par ailleurs, Mme McShane précise que si le MÉAF fonctionne parfaitement, alors la prime de risque des sociétés réglementées devrait être inférieure à la prime de risque du marché. La Régie juge néanmoins que la prime de risque d'un distributeur repère, produit à partir du modèle basé sur l'historique de cette prime de risque, est élevée.

[23] Quant au modèle AFM, la Régie est d'avis que ce modèle comporte certaines difficultés pratiques, notamment quant à l'estimation du taux de croissance des dividendes des titres choisis. La Régie note que l'application de ce modèle, que ce soit par la méthode directe ou indirecte, se fait à partir de données américaines uniquement. La Régie note également que l'application de la méthode indirecte du modèle AFM se fait à partir des rendements réalisés des sociétés de gestion américaines qui incluent des actifs réglementés et non réglementés.

[24] **En regard de la preuve soumise, la Régie retient principalement, aux fins de sa décision, le modèle d'évaluation des actifs financiers.** Il s'agit de l'approche retenue par la Régie dans ses décisions antérieures. De plus, ce modèle est reconnu et utilisé tant dans les milieux de la finance que par la majorité des experts témoignant devant les organismes de réglementation.

[25] L'utilisation de ce modèle comporte cependant, dans le contexte actuel, des difficultés que la Régie aborde plus en détails dans les sections suivantes.

2 Pièce A-35-2, pages 27 à 30.

[26] Par mesure de prudence, comme aucun modèle ne peut reproduire parfaitement à lui seul les attentes de rendement des investisseurs, la Régie prend en considération, aux fins de son appréciation du taux de rendement sur l'avoir de l'actionnaire de Gazifère, les résultats des autres modèles de type « prime de risque » et AFM de Mme McShane ainsi que du modèle multifacteur utilisé par le D^r Booth. La Régie traite plus en détails de ce sujet à la section 2.2.6.

### 1.1.1 TAUX SANS RISQUE

[27] L'application du MÉAF requiert l'établissement d'un taux sans risque ($R_f$) auquel s'ajoutera la prime de risque de l'entreprise. Selon la pratique usuelle dans la réglementation canadienne, le taux sans risque utilisé est celui des obligations de long terme de 30 ans du gouvernement du Canada.

[28] Mme McShane révise son taux sans risque lors de l'audience à 4,15 % pour l'application des modèles de type « prime de risque »[3]. Ce taux est établi sur la base du Consensus Focecasts du mois d'août 2010[4].

[29] Le D^r Booth appuie son jugement sur une hypothèse de croissance économique normale et un taux d'inflation de 2 %. Il retient un taux sans risque de 4,5 %.

[30] Enfin, selon la méthode d'établissement habituelle découlant du Consensus Forecasts du mois d'octobre 2010 et de l'écart entre le rendement des obligations du gouvernement du Canada de 10 ans et de 30 ans pour le mois précédent, le taux sans risque se situe à 3,644 %, tel que déposé par Gazifère[5].

[31] **Sur la base de la preuve au dossier, la Régie établit le taux sans risque dans une fourchette variant de 4,15 % à 4,50 %.**

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3 Ce taux était établi à 4,7 % lors du dépôt de sa preuve.

4 Consensus Forecasts, 9 août 2010.

5 Pièce B-45, GI-30, document 5, page 1. Cette pièce a été déposée le 18 octobre 2010.

### 1.1.2 PRIME DE RISQUE DU MARCHÉ

[32] Le MÉAF requiert l'établissement de la prime de risque du marché ($R_m - R_f$) en fonction de laquelle sera établie la prime de risque d'une entreprise réglementée type, communément appelée un distributeur repère.

[33] Selon Mme McShane, la prime de risque du marché se situe à 6,75 %. Elle est d'avis que la prime de risque sera plus élevée que la moyenne historique, compte tenu que les rendements futurs des obligations seront plus faibles que ceux observés historiquement et que les rendements futurs, dans le marché boursier, seront semblables à ceux observés historiquement. Enfin, selon cette experte, les effets de la crise financière dans les marchés des capitaux seraient chose du passé[6].

[34] Le Dr Booth présente des estimations de la prime de risque du marché à partir de séries de données couvrant des périodes débutant en 1926 et en 1957 et se terminant en 2009. Il établit ses estimations à partir des moyennes arithmétique et géométrique et de la méthode des moindres carrés ordinaires. Il recommande une prime de risque du marché de 5,5 %. Sa recommandation est corroborée par une étude du professeur Fernandez. Les résultats de cette étude ont été établis à partir des opinions d'un échantillon de professeurs de finance, d'analystes financiers et de dirigeants de sociétés[7].

[35] Le Dr Booth considère la reprise économique fragile et les écarts de crédit supérieurs à ce qu'ils devraient être dans un cycle économique normal. Il recommande un ajustement de 50 points de base pour les effets liés à la crise financière.

[36] Dans sa décision D-2009-156[8], la Régie, aux fins d'estimer la prime de risque du marché, utilisait des proportions égales pour les données canadiennes et pour les données américaines. En tenant compte de la preuve au présent dossier, la Régie utilise la même approche.

[37] La Régie maintient l'établissement de la prime de risque du marché sur la base de la moyenne arithmétique des rendements observés sur les marchés. Le choix des périodes de référence pour établir la prime de risque soulève cependant certains enjeux. En effet, la

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6 Pièce A-35-1, page 32.
7 Pièce C-2-13, preuve du Dr Booth, pages 40 à 42.
8 Dossier R-3690-2009, page 62.

moyenne calculée peut différer sensiblement selon l'année de départ et de fin et la série de données retenues. Dans ce contexte, la Régie choisit d'accorder une prépondérance aux moyennes de longues périodes.

[38] **Sur la base de la preuve au dossier, la Régie établit la prime de risque du marché, avant prise en considération des effets de la crise financière, dans une fourchette variant de 5,50 % à 5,75 %.**

[39] En ce qui a trait aux effets de la crise financière, la Régie retient le point de vue du D^r Booth selon lequel la reprise économique est fragile et que les écarts de crédit sont encore supérieurs à ce qu'ils devraient être dans un cycle économique normal.

[40] Compte tenu de la preuve au dossier et de l'objectif de maintenir un accès au marché à des conditions raisonnables, la Régie juge qu'il y a lieu d'octroyer, dans les circonstances du présent dossier, un ajustement pour tenir compte des effets de la crise financière.

[41] **Par conséquent, la Régie établit, pour tenir compte des effets de la crise financière, une majoration de la prime de risque du marché dans une fourchette variant de 0,50 % à 1 %.**

### 1.1.3 RISQUE D'UN DISTRIBUTEUR REPÈRE

[42] Le D^r Booth et Mme McShane présentent une estimation du risque d'un distributeur repère, soit une société de service public présentant un niveau de risque faible. Le risque d'un distributeur repère est mesuré par le facteur bêta (β). Celui-ci représente le différentiel de risque entre la société repère et le marché en général.

[43] L'établissement du bêta comporte des difficultés importantes. Ces difficultés ont trait, entre autres, à l'établissement d'un échantillon de référence représentatif du risque des sociétés réglementées ainsi qu'à l'obtention de séries de données valables pour procéder à une estimation robuste.

[44] Mme McShane présente un bêta ajusté se situant dans une fourchette de 0,65 à 0,70 calculé à partir de différents tests. Elle présente également un bêta brut de 0,44 calculé par Bloomberg à partir d'un échantillon de sociétés canadiennes.

[45] Le D^r Booth présente divers estimés basés sur les données récentes, mais souligne qu'il est nécessaire de faire preuve de jugement et propose donc d'établir le bêta d'un distributeur repère sur la base de la moyenne historique, qu'il évalue entre 0,45 et 0,55.

[46] Mme McShane utilise des bêtas ajustés pour tenir compte des recherches empiriques montrant la tendance des bêtas à converger vers 1. Le D^r Booth soutient plutôt que les bêtas des sociétés réglementées convergent vers leur propre moyenne et non vers 1.

[47] Après examen, la Régie maintient la position exprimée dans ses décisions antérieures[9] voulant que les bêtas des sociétés réglementées convergent vers la moyenne qui leur est propre et non vers celle du marché qui, par définition, est égale à un 1.

[48] **Sur la base de la preuve au dossier, la Régie établit le bêta d'un distributeur repère dans une fourchette de 0,50 à 0,55.**

### 1.1.4 RISQUE DE GAZIFÈRE

[49] Le risque d'affaires de Gazifère par rapport au risque d'un distributeur repère a fait l'objet d'un examen approfondi en 1999. Dans le cadre du présent dossier, la Régie réexamine ce risque.

[50] Un témoin de Gazifère, Mme Vandal-Parent, mentionne, lors de l'audience, que les liens d'affaires créés avec les entrepreneurs en construction pourraient s'effriter en raison de la retraite potentielle de ces derniers. En effet, la croissance soutenue qu'a connue Gazifère ces dernières années dans le secteur résidentiel serait le résultat, entre autres, des

[9] Décision D-2009-156, dossier R-3690-2009; décision D-2007-116, dossier R-3630-2007; décision D-2003-93, dossier R-3492-2002 Phase 1 et décision D-2002-95, dossier R-3401-98.

liens d'affaires entretenus par Gazifère avec ces entrepreneurs. Si ceux-ci devaient prendre leur retraite, Gazifère pourrait voir sa croissance limitée[10].

[51] Selon Mme McShane, le risque d'affaires pour l'investisseur est l'incertitude liée à la réalisation du rendement sur son capital ainsi qu'à la récupération de son capital.

[52] Mme McShane indique que Gazifère est une petite société réglementée pour laquelle aucun comparable direct n'existe. Elle utilise son jugement pour quantifier le risque additionnel de Gazifère par rapport au risque d'un distributeur repère.

[53] Elle présente un tableau des décisions des régulateurs canadiens. Elle admet la circularité de cette comparaison mais soutient que cette information demeure utile aux fins de son analyse.

[54] Par la suite, Mme McShane discute du concept d'isolement. Ce concept permet d'établir, sur une base théorique, quel serait le coût des capitaux de Gazifère si celle-ci était une société totalement indépendante. Cette approche repose sur le principe économique des coûts d'opportunité où le coût de chaque ressource, capital compris, est celui qui correspond à ses alternatives. Il en découle que le coût des capitaux propres est équivalent au coût d'opportunité pour les investisseurs, un coût ajusté selon le risque, peu importe l'identité de ces investisseurs. Ainsi, les facteurs pertinents dont on doit tenir compte pour établir le coût du capital de Gazifère sont les alternatives offertes aux investisseurs ainsi que les risques et les rendements associés à ces alternatives. Selon elle, en raison de sa petite taille, Gazifère ne pourrait obtenir une cote de crédit plus élevée que BBB.

[55] À partir de ce concept d'isolement, elle utilise le MÉAF et le modèle AFM pour établir une fourchette entre 50 et 80 points de base de risque additionnel pour une société réglementée de cote BBB par rapport à un distributeur repère de cote A.

[56] Mme McShane s'appuie également sur une étude d'Ibbotson Associates pour estimer le risque additionnel d'une petite société. Cette étude démontre que les petites sociétés ont des bêtas plus élevés que les grandes sociétés. Selon cette étude, l'écart entre les bêtas des petites et moyennes sociétés devraient être de 0,32. Au total, le risque additionnel associé à une petite société est d'environ 200 points de base. Il faut noter,

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[10] Pièce A-35-1, page 19.

cependant, que cette étude porte sur l'ensemble des sociétés et non uniquement sur les sociétés réglementées.

[57] En conclusion, Mme McShane recommande une prime de risque additionnelle de 50 points de base par rapport à un distributeur repère.

[58] L'ACIG indique que la preuve ne démontre pas un risque accru particulièrement élevé pour Gazifère, surtout par rapport à ce qu'il était en 1999. Les preuves respectives de l'expert et de l'analyste de l'intervenante tendent à démontrer que ce risque est largement atténué.

[59] En effet, selon l'analyse de l'ACIG, plusieurs facteurs démontrent que le risque d'affaires de Gazifère est réduit comparativement à 1999. L'intervenante note la nouvelle composition de la clientèle et le développement de l'économie de service dans la région de la Capitale nationale du Canada en relation avec la réduction de la dépendance de Gazifère envers le secteur industriel.

[60] Selon l'intervenante, Gazifère exploite sa franchise de distribution dans un environnement économique favorable et supérieur à la moyenne. De plus, Gazifère a démontré une très bonne capacité à excéder son rendement autorisé, même pendant la récente crise financière.

[61] L'ACIG note également que la composition de la clientèle de Gazifère est constituée à 93 % de clients qui utilisent le gaz naturel pour le chauffage de l'espace et de l'eau et qui ne peuvent aisément passer à une autre source d'énergie. Ces clients sont captifs et plus difficiles à perdre que des clients industriels interruptibles qui ont la capacité d'avoir recours à des sources d'énergie alternatives. De plus, la composition de sa clientèle actuelle rend le distributeur moins dépendant envers les clients industriels qui représentent maintenant seulement 6 % de ses revenus, incluant 4,5 % pour le secteur des pâtes et papiers.

[62] L'ACIG constate que la situation concurrentielle de Gazifère, en raison du prix actuel du gaz naturel, est avantageuse par rapport à l'huile à chauffage. La situation concurrentielle de Gazifère s'est également améliorée depuis 1999 face à l'électricité. En effet, un gel des tarifs d'électricité était en cours en 1999 et a perduré jusqu'en 2004. Or, depuis, il y a eu des hausses régulières des tarifs d'électricité. Prospectivement, en raison des besoins d'investissements du réseau de distribution et de transport d'électricité ainsi

que des coûts d'approvisionnement plus élevés, les tarifs d'électricité devraient continuer à augmenter. De plus, l'intervenante remarque que l'approche commerciale d'Hydro-Québec dans le marché de la construction est maintenant moins agressive que par le passé.

[63] Également, l'ACIG mentionne que la réduction des volumes par client en raison, notamment, de mesures d'efficacité énergétique, n'est aucunement préjudiciable à Gazifère, puisque cela a pour effet de réduire la facture totale pour chaque client. Selon l'ACIG, la facture totale étant moins élevée, chaque client est plus enclin à demeurer au gaz naturel qu'à se tourner vers des sources d'énergie alternatives.

[64] L'ACIG ajoute que le mécanisme incitatif de Gazifère ne crée aucun risque additionnel à court terme. Cette constatation s'appuie, notamment, sur la capacité de Gazifère d'excéder son rendement autorisé pendant la récente crise financière.

[65] Enfin, le D^r Booth, comme l'intervenante, conclut à une légère réduction du risque d'affaires de Gazifère depuis 1999. Le D^r Booth recommande une prime de risque additionnelle de 25 points de base par rapport à un distributeur repère.

[66] La Régie évalue le risque global de Gazifère supérieur à la moyenne, notamment en raison de sa taille et de la concurrence de l'électricité au Québec. Cependant, elle tient compte, dans son appréciation, de la couverture plus étendue de ces mêmes risques par des comptes de frais reportés.

[67] La Régie juge que le risque de Gazifère ne s'est pas modifié significativement depuis la décision D-99-09[11], bien qu'il demeure supérieur à celui d'un distributeur repère. **Sur la base de la preuve au dossier, la Régie évalue que le risque plus élevé justifie un ajustement à la hausse, par rapport à la prime de risque d'un distributeur repère, de l'ordre de 25 à 50 points de base.**

11 Dossier R-3406-98.

### 1.1.5 FRAIS D'ÉMISSION ET AUTRES COÛTS D'ACCÈS AUX MARCHÉS DES CAPITAUX

[68] Selon Mme McShane, ces frais comprennent trois éléments, soit les frais d'émission, un coussin pour les conditions de marché non anticipées et le principe de maintenir la valeur au marché des actifs au-dessus de la valeur aux livres. Elle recommande 75 points de base pour ces frais.

[69] Le Dr Booth recommande d'ajouter 50 points de base à son estimé du rendement requis pour l'actionnaire, pour tenir compte des frais d'émission et des effets de dilution. Un tel ajustement serait compatible avec la pratique appliquée par plusieurs régulateurs.

[70] L'ACIG mentionne que le concept de Mme McShane pour ces frais est plus large que celui utilisé traditionnellement. De plus, l'intervenante souligne que ce concept plus large inclut des éléments plus ou moins abstraits qui font appel à un jugement de valeur, par exemple un coussin pour les conditions de marché non anticipées.

[71] La Régie juge que les éléments historiquement utilisés pour établir les frais d'émission et autres coûts d'accès aux marchés des capitaux sont suffisants. Elle rejette la proposition de Mme McShane qui repose sur un concept plus large que ce que la Régie a exprimé dans ses décisions précédentes sur ce sujet.

[72] Dans le dossier de Gaz Métro traité l'an dernier, les frais d'émission ont fait l'objet d'un examen détaillé. Dans sa décision D-2009-156, la Régie a jugé qu'une provision pour frais d'émission et autres frais d'accès aux marchés se situant dans une fourchette de 30 à 40 points de base constituait une compensation suffisante. Cette compensation a été établie après avoir examiné les coûts réels des émissions chez Gaz Métro depuis 1993.

[73] Contrairement au cas de Gaz Métro qui émet des titres sur les marchés pour obtenir des capitaux propres, dans le cadre du présent dossier la Régie doit plutôt établir pour Gazifère un estimateur de ces frais. Elle procède donc sur une base théorique, à partir de la preuve au dossier, plutôt que sur une base de coûts réellement encourus.

[74] **Conséquemment, la Régie établit pour Gazifère la provision pour frais d'émission et autres frais d'accès aux marchés des capitaux à 50 points de base.**

### 1.1.6 Résultats des autres modèles

[75] Selon la Régie, le MÉAF demeure le modèle de référence le plus approprié pour servir de guide dans la détermination d'un taux de rendement raisonnable sur l'avoir de l'actionnaire.

[76] Cependant, il est aussi admis par tous les experts qu'aucun modèle ne peut, à lui seul, représenter correctement les attentes des investisseurs dans toutes les circonstances et dans toutes les phases des cycles économiques et financiers. En conséquence, la Régie juge nécessaire de prendre en considération les résultats produits par les autres modèles présentés par les experts.

[77] Par ailleurs, la Régie rappelle que, dans sa décision D-2007-116[12], elle mentionnait que l'application du MÉAF présentait une difficulté particulière lorsque la détermination du rendement dans un dossier intervient dans une période où les taux courants des obligations gouvernementales s'écartent de façon significative du taux moyen de longue période. La prime de risque étant calculée sur de longues périodes et représentant la différence entre la moyenne arithmétique des rendements du marché et de ceux des obligations gouvernementales, cette prime est donc représentative des conditions qui prévalent sur cette même période. La Régie concluait qu'un ajustement s'imposait lorsque les conditions du marché obligataire s'éloignent de cette moyenne.

[78] **Compte tenu de la preuve au présent dossier, la Régie juge qu'un ajustement de l'ordre de 25 à 50 points de base par rapport aux résultats du modèle d'évaluation des actifs financiers est justifié dans les circonstances.**

### 1.1.7 Comparaison avec les distributeurs américains

[79] Afin de vérifier la validité des tests qu'elle propose, Mme McShane applique ces tests sur un échantillon d'entreprises de distribution. Pour être incluses dans l'échantillon, ces entreprises doivent émettre des titres transigés sur les marchés. Elles doivent également présenter un risque similaire au distributeur repère. Selon Mme McShane, il n'est pas possible d'utiliser un échantillon de sociétés réglementées canadiennes aux fins

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12 Dossier R-3630-2007, page 28.

d'estimation du coût du capital[13]. En effet, selon elle, les sociétés réglementées canadiennes sont très différentes les unes des autres et, par conséquent, ne peuvent servir aux fins de comparaison pour une société réglementée en particulier ou pour l'industrie dans son ensemble.

[80] À cette fin, elle utilise un échantillon de sociétés américaines pour valider les résultats de ces tests. Selon elle, aucun ajustement n'est nécessaire, puisque l'environnement réglementaire, légal, fiscal et comptable canadien est similaire à celui prévalant aux États-Unis. Cependant, elle reconnaît que l'application réglementaire n'est pas identique[14].

[81] Pour effectuer les différents tests aux fins d'estimation du coût du capital, Mme McShane utilise les données fournies par Standard and Poor's. En audience, elle indique que ces données sont basées sur un échantillon de sociétés américaines qui ont des activités réglementées et non réglementées. Elle indique également qu'elle ne connaît pas la relation exacte entre les rendements réalisés attribuables uniquement aux activités réglementées des sociétés américaines de son échantillon et les rendements autorisés[15].

[82] Selon l'ACIG, dans la décision D-2009-156 la Régie a formulé de sérieuses réserves quant à l'usage d'un échantillon de distributeurs américains ou de rendements accordés à des distributeurs américains à titre de comparables aux fins de la détermination du taux de rendement d'un distributeur repère.

[83] L'ACIG réitère que le présent dossier n'a toujours pas permis d'identifier les taux de rendement réalisés attribuables uniquement aux activités réglementées des sociétés américaines par opposition aux rendements des sociétés de gestion qui les chapeautent, pas plus d'ailleurs que la comparaison entre les taux de rendement réalisés et les rendements autorisés.

[84] L'ACIG indique que Mme McShane a admis qu'il y a une volatilité importante des rendements réalisés par rapport au rendement autorisé, ce qui est important au niveau du risque à court terme. Selon l'ACIG, l'experte a également admis qu'il y a un usage beaucoup plus important et répandu des comptes de frais reportés au Canada, pratique qui

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13 Pièce A-35-1, pages 35 et 36.

14 Pièce B-1, GI-30, document 1, pages 10 à 14.

15 Pièce A-35-1, pages 179 et 180.

procure aux distributeurs canadiens une plus grande stabilité au niveau des rendements réalisés.

[85] Enfin, le D^r Booth souligne, dans sa présentation à l'audience intitulée « *US Data* », que Moody's considère que le risque réglementaire est, dans la majorité des cas, plus élevé pour les sociétés réglementées américaines que pour les sociétés réglementées canadiennes[16].

[86] Selon le D^r Booth, les pourcentages de capitaux propres dans la structure de capital des sociétés réglementées américaines sont plus élevés que ceux des sociétés réglementées canadiennes. Normalement, cette capitalisation plus élevée devrait les protéger contre un risque accru. Le D^r Booth montre, dans sa présentation[17] en audience, que la cote de crédit des sociétés réglementées américaines est de type BBB.

[87] L'ACIG conclut que la preuve dans le présent dossier n'apporte pas un éclairage nouveau suffisant pour permettre à la Régie d'en arriver à des conclusions différentes de celles auxquelles elle est parvenue dans la décision D-2009-156.

[88] La Régie juge que la preuve est peu concluante quant aux raisons qui justifieraient de retenir les taux accordés aux États-Unis comme base de référence pour établir un taux de rendement raisonnable au Québec. La preuve est, en effet, insuffisante quant aux données récentes sur les décisions américaines et quant à l'analyse des régimes réglementaire et institutionnel en vigueur chez nos voisins. Entre autres, le distributeur n'a pas fait la démonstration que les opportunités qui s'offrent sur le marché américain sont comparables, en termes de risque.

[89] De plus, la Régie juge que la preuve ne permet pas de conclure que les contextes réglementaire, institutionnel, économique et financier des deux pays et leurs impacts sur les opportunités qui en découlent pour les investisseurs sont comparables.

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[16] Pièce C-2-26.
[17] Pièce C-2-26.

### 1.1.8 RÉSULTATS DE L'ANALYSE

[90] Le tableau suivant résume les valeurs retenues par la Régie pour chacun des paramètres.

**Tableau 1**

| **Paramètres** | **Bas de la fourchette** | **Haut de la fourchette** |
|---|---|---|
| Taux sans risque | 4,15 % | 4,50 % |
| Prime de risque du marché avant la prise en compte des effets de la crise financière | 5,50 % | 5,75 % |
| Bêta brut d'un distributeur repère | 0,50 | 0,55 |
| Ajustement pour le risque de Gazifère | 0,25 % | 0,50 % |
| Frais d'émissions | 0,50 % | 0,50 % |
| **Sous-total n° 1 : Résultat produit par le MÉAF** | **7,65 %** | **8,66 %** |
| Ajustement pour tenir compte des résultats des autres modèles | 0,25 % | 0,50 % |
| **Sous-total n° 2 : Taux de rendement sur l'avoir de l'actionnaire avant ajustement pour tenir compte des effets de la crise financière** | **7,90 %** | **9,16 %** |
| Ajustement pour tenir compte des effets de la crise financière | 0,25 % | 0,55 % |
| **Total : Taux de rendement sur l'avoir de l'actionnaire après ajustement pour tenir compte des effets de la crise financière** | **8,15 %** | **9,71 %** |

[91] Tenant compte de l'ensemble des conclusions précédentes, le taux de rendement sur l'avoir de l'actionnaire de Gazifère se situe dans une fourchette variant de 7,90 % à 9,16 %, avant ajustement pour les effets de la crise financière, et entre 8,15 % et 9,71 %, après ajustement pour les effets de la crise financière.

[92] **Sur la base de la preuve au dossier et pour l'ensemble des motifs exprimés précédemment, la Régie fixe le taux de rendement sur l'avoir de l'actionnaire de Gazifère à 9,10 % pour l'année tarifaire 2011. Ce taux inclut un ajustement de 30 points de base pour tenir compte des effets de la crise financière.**

## 1.2 FORMULE D'AJUSTEMENT AUTOMATIQUE

[93] À la suite d'une demande de la Régie, Gazifère dépose le calcul du taux de rendement sur l'avoir de l'actionnaire pour 2011 résultant de l'application de la formule d'ajustement actuelle. Ce taux de rendement s'établit à 8,46 %[18].

[94] Mme McShane recommande une nouvelle formule d'ajustement du taux de rendement pour tenir compte des écarts de crédit corporatif et d'une sensibilité moindre du coût de l'avoir propre aux variations des rendements des obligations du gouvernement.

[95] Mme McShane présente deux analyses au soutien de sa conclusion à l'effet que la sensibilité du coût de l'avoir propre aux variations des taux de rendement des obligations à long terme du gouvernement est plus petite que le facteur 0,75 de la présente formule. Ces analyses sont effectuées à partir de données américaines uniquement.

[96] Selon elle, même si les résultats de deux analyses produisent des estimateurs différents quant au facteur de sensibilité, il demeure que le coût de l'avoir propre est positivement relié aux variations observées entre les taux de rendement des obligations des sociétés et ceux des obligations du gouvernement.

[97] Dans la première analyse, Mme McShane fait une régression entre les taux de rendement trimestriels de 1995 à 2009, les rendements des obligations à long terme du gouvernement américain et l'écart entre les taux de rendement des obligations des sociétés de gestion américaines de cote A , dont une partie des actifs est réglementée, et les rendements des obligations à long terme du gouvernement américain.

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[18] Pièce B-45, GI-30, document 5.

[98] Il en résulte que pour une augmentation (diminution) de 100 points de base des rendements des obligations à long terme du gouvernement américain, le coût de l'avoir de l'actionnaire augmente (diminue) de 47 points de base. Pour une augmentation (diminution) de 100 points de base de l'écart entre les taux de rendement des obligations des sociétés de gestion américaines de cote A et les rendements des obligations à long terme du gouvernement américain, le coût de l'avoir propre augmente (diminue) de 27 points de base.

[99] La deuxième analyse de Mme McShane teste, à partir du modèle AFM, la sensibilité du coût de l'avoir de l'actionnaire de 1995 à 2009 par rapport à, d'une part, la variation des rendements des obligations à long terme du gouvernement américain et, d'autre part, la variation de l'écart entre les taux de rendement des obligations des sociétés de gestion américaines de cote A et les rendements des obligations à long terme du gouvernement américain.

[100] Il en résulte que pour une augmentation (diminution) de 100 points de base des rendements des obligations à long terme du gouvernement américain, le coût de l'avoir propre augmente (diminue) de 65 points de base. Pour une augmentation (diminution) de 100 points de base de l'écart entre les taux de rendement des obligations des sociétés de gestion américaines de cote A et les rendements des obligations à long terme du gouvernement américain, le coût de l'avoir propre augmente (diminue) de 90 points de base.

[101] À partir de ces résultats, Mme McShane recommande la formule d'ajustement ci-dessous :

Le nouveau taux de rendement serait égal :

- au taux de rendement initial;
- plus 50 % de la variation du taux de rendement des obligations de 30 ans du gouvernement du Canada par rapport à celui fixé initialement;
- plus 50 % de la variation du taux de rendement des obligations à long terme de l'ensemble des sociétés canadiennes de cote A par rapport à celui fixé initialement. L'indice obligataire corporatif utilisé est le *DEX Long Term Index Corporate A*.

[102] Mme McShane produit un tableau montrant quel aurait été le taux de rendement sur l'avoir de l'actionnaire selon cette formule par rapport aux rendements autorisés de 1995 à 2011 par l'Office national de l'énergie (ONÉ)[19].

[103] L'experte McShane précise que le taux de rendement s'élève en moyenne à 10,6 %, soit un rendement comparable à la moyenne des taux autorisés aux États-Unis, qui est de 10,9 %. Elle conclut donc que cette formule est supérieure à celle que la Régie utilise présentement car elle produit des résultats comparables à ceux obtenus aux États-Unis.

[104] Enfin, Mme McShane propose que le taux de rendement et la formule soient révisés à tous les cinq ans, à moins que le taux de rendement autorisé par l'application de la nouvelle formule soit supérieur ou inférieur à 200 points de base du taux de rendement autorisé initialement.

[105] Le D$^{r}$ Booth est d'avis qu'il n'est pas nécessaire de changer la formule d'ajustement qui s'applique actuellement. Si la Régie décidait de changer cette formule, il propose, subsidiairement, une formule alternative qui tient compte des variations des rendements des obligations à long terme des sociétés réglementées de cote A.

[106] Subsidiairement, le D$^{r}$ Booth propose la formule d'ajustement ci-dessous :

Le nouveau taux de rendement serait égal :

- au taux de rendement initial;
- plus 75 % de la variation du taux de rendement des obligations de 30 ans du gouvernement du Canada par rapport à celui fixé initialement;
- plus 50 % de la variation du taux de rendement des obligations de 30 ans des sociétés réglementées canadiennes de cote A par rapport à celui fixé initialement (appelé ci-dessous écart de crédit). L'indice obligataire corporatif utilisé est l'indice C29530Y de Bloomberg.

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19 Pièce B-1, GI-4, document 1.2, schedule 28.

[107] Le D$^{r}$ Booth précise que le facteur de 0,50 pour tenir compte des écarts de crédit lui semble excessif. Il le conserve cependant, en précisant que sur la durée d'un cycle économique complet, l'effet est neutre. Selon un rapport de la Banque du Canada, le facteur d'ajustement dû aux changements des écarts de rendement des obligations corporatives relié au risque de défaut, qui peut être lié à un changement du coût de l'avoir propre, serait de l'ordre de 37 %[20].

[108] À partir de cette formule, le D$^{r}$ Booth refait le même exercice que Mme McShane, à savoir déterminer quel aurait été le taux de rendement sur l'avoir propre selon sa formule par rapport aux rendements autorisés de 1995 à 2011 par l'ONÉ.

[109] Selon le D$^{r}$ Booth, les taux de rendement produits par la formule de Mme McShane sont supérieurs aux taux de rendement autorisés de 1995 à 2011 par l'ONÉ. Selon lui, cela implique qu'aucun régulateur canadien n'aurait autorisé des rendements raisonnables sur cette période. Il ajoute également que, pendant cette période, les régulateurs canadiens ont refait l'exercice plus d'une fois, sur la base de preuves d'experts.

[110] Selon le D$^{r}$ Booth, la différence entre les taux de rendement produits par sa formule et les taux de rendement autorisés par l'ONÉ pour l'ensemble de la période de 1995 à 2011 est minime. Cependant, il y a des différences importantes pour certaines années, comme en 2009.

[111] Le D$^{r}$ Booth détermine quel aurait été le taux de rendement de Gazifère si la formule qu'il propose avait été employée. Il utilise le taux de rendement autorisé de Gazifère en 1999, qui était de 10 % avec un taux sans risque de 5,7 %. À partir des hypothèses que le taux sans risque est présentement de 4,5 % et que l'écart de crédit en 1999 était de 0,99 %, le rendement de Gazifère serait de 9,25 % selon sa formule. Le D$^{r}$ Booth considère qu'un écart de crédit normal serait de l'ordre de 94 points de base[21].

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[20] Pièce C-2-13, preuve du D$^{r}$ Booth, page 64.

[21] Pièce C-2-13, preuve du D$^{r}$ Booth, page 64.

[112] Le Dr Booth considère cependant que les régulateurs n'ont pas besoin d'une formule qui capte les impacts de la pire crise financière depuis 1937, étant donné que la formule proposée génèrera une volatilité accrue des rendements autorisés annuels, et ce, pour peu de gain. Il est à noter également que l'ACIG est plutôt défavorable au deuxième ajustement de la formule proposée.

[113] Enfin, le Dr Booth note que si cette formule devait être retenue, la Régie ne devrait pas accorder un ajustement supplémentaire pour les effets de la crise financière.

[114] La Régie constate que la formule proposée par Mme McShane produit des rendements supérieurs à ceux autorisés par le passé. Quant à celle du Dr Booth, elle produit, sur un cycle économique, des rendements semblables à ceux octroyés, bien que, sur une base annuelle, ceux-ci divergent de ceux autorisés.

[115] La Régie est d'avis que la formule du Dr Booth permet de faire fluctuer le taux de rendement en fonction de la variation du taux de rendement des obligations de 30 ans des sociétés réglementées canadiennes, tout en gardant un rendement similaire à ceux autorisés sur une période d'un cycle économique. La Régie prend note que selon l'étude de la Banque du Canada, le facteur d'ajustement pour les écarts de crédit serait de l'ordre de 0,37.

[116] La Régie évalue que la formule alternative du Dr Booth aurait permis, malgré une volatilité accrue des rendements autorisés, d'obtenir des rendements autorisés mieux adaptés durant la crise financière. **La Régie conclut qu'il y a lieu de remplacer la formule actuelle par celle du Dr Booth aux fins d'établir le taux de rendement à compter de 2012.**

[117] La Régie est d'avis que les écarts de rendement des obligations des sociétés réglementées de cote A ne réagissent pas de la même façon que les écarts de rendement des obligations des sociétés non réglementées de cote A pendant les cycles économiques, et ce, particulièrement pendant une crise financière. **La Régie retient l'indice C29530Y de Bloomberg comme estimateur des écarts de crédit des sociétés réglementées canadiennes. Pour les prochains dossiers tarifaires, la Régie demande donc à Gazifère de fournir les données de Bloomberg du mois de septembre aux fins de l'application de la nouvelle formule.**

[118] En audience, le D$^{r}$ Booth a indiqué que l'indice de Bloomberg, lors du dépôt de sa preuve, était de 1,3 % alors qu'au moment de l'audience, il était d'environ 1,5 %[22]. **La Régie retient la valeur de 1,5 % de l'indice Bloomberg aux fins d'application de la nouvelle formule.** Sur la base d'un écart de crédit normal estimé à environ 90 points de base, l'ajustement pour les écarts de crédit ajoute, avec la nouvelle formule, 30 points de base au taux de rendement.

[119] La Régie retient pour l'année tarifaire 2011 un ajustement de 30 points de base pour l'effet de la crise financière. **La Régie estime que, pour 2012 et les années subséquentes, cet ajustement est pris en compte par le deuxième membre de la nouvelle formule d'ajustement automatique.** Ainsi, dans l'éventualité où les écarts de crédit demeurent élevés, l'ajustement sera maintenu. À l'inverse, si les écarts de crédit reviennent à leur normale, l'ajustement sera enlevé.

[120] **La Régie fixe également, aux fins de l'application de la nouvelle formule, le taux sans risque à 4,25 %.**

[121] Ainsi, le taux de rendement sur l'avoir de l'actionnaire pour l'année 2012 et les années subséquentes sera calculé selon la formule présentée à l'annexe 1.

[122] La Régie précise que le taux de rendement sur l'avoir de l'actionnaire résultant de l'application de cette formule devra être exprimé en pourcentage arrondi à deux décimales.

## 1.3 COÛT DE LA DETTE

[123] Gazifère explique en audience que le financement se fait exclusivement auprès d'Enbridge Inc. (Enbridge), sa société mère. La dette à court terme de Gazifère est une proportion de la marge de crédit consolidée dans Enbridge.

[124] Le taux de la dette à court terme utilisé par Gazifère correspond au taux d'escompte établi par le service « *Economic & Market Analysis* » d'Enbridge Gas Distribution Inc. (EGD).

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[22] Pièce A-35-2, pages 141 et 142.

[125] Gazifère dépose la méthodologie et les données utilisées pour établir ce taux d'escompte[23]. Selon cette méthodologie, la moyenne des prévisions de taux directeur de six institutions financières est ajustée pour obtenir un taux raisonnable. Une prime de 2 %, représentant l'écart entre le taux directeur et le taux préférentiel de la Banque du Canada depuis décembre 2008, est ajoutée à cette prévision.

[126] Le taux en résultant passe de 2,21 % en 2010 à 3,90 % en 2011[24].

[127] La Régie constate que les fluctuations de ce taux sont importantes. Elle constate aussi que la méthodologie utilise certains paramètres peu documentés, comme l'ajustement à la moyenne des taux ainsi que la période utilisée pour établir l'écart de 2 %.

[128] **La Régie demande à Gazifère de déposer, pour examen dans le prochain dossier tarifaire, la méthodologie et les données utilisées pour établir le taux d'escompte, en incluant minimalement les données présentées à la pièce B-43, GI-41, document 1.1.**

[129] Par ailleurs, les émissions de la dette à long terme de Gazifère sont financées par Enbridge au taux des obligations de 10 ans du gouvernement du Canada plus une prime de risque pour tenir compte de la cote de crédit de Gazifère selon le concept d'isolement.

[130] Gazifère dépose la méthodologie d'établissement du coût de la dette à long terme[25]. L'établissement de la cote de crédit et de la prime de risque repose sur une évaluation de *RBC Capital Markets*. Étant donné sa taille, la cote de crédit de Gazifère est évaluée comme un « BBB bas ».

[131] En audience, Gazifère indique qu'au cours des dernières années, il n'y a pas eu de modification à la méthodologie retenue pour établir son financement. Elle dépose les primes de risque annuelles qui ont été utilisées pour établir le coût de sa dette depuis 2002[26]. À partir de ce document, il peut être constaté que les primes de risque sont volatiles.

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[23] Pièce B-43, GI-41, document 1.1.

[24] Pièce B-41, GI-35, document 2.2, page 2.

[25] Pièce B-11, GI-31, document 1.3 et pièce B-38, GI-30, document 4.1.

[26] Pièce B-38, GI-30, document 3.

[132] Gazifère souligne qu'elle et Enbridge, en plus d'être deux sociétés distinctes, sont régies par deux organismes de réglementation distincts et sont assujetties à toute une panoplie de législations distinctes.

[133] Gazifère rappelle que la méthodologie pour établir le coût de sa dette a été approuvée par la Régie dans la décision D-2006-158[27]. Selon Gazifère, le principe du concept d'isolement a été reconnu dans cette décision et c'est exactement de cette façon qu'elle a établi le coût de la dette dans le présent dossier.

[134] Enfin, Mme McShane indique que si Gazifère émettait ses propres titres de dette, le coût de financement serait plus élevé et les conditions seraient plus contraignantes. Elle conclut que les clients de Gazifère doivent payer le coût de la dette comme si elle se finançait seule. En d'autres mots, il faut appliquer le concept d'isolement.

[135] Selon le D^r^ Booth, s'il n'y avait pas de frontière provinciale, les actifs de Gazifère ne seraient pas différents de ceux d'Enbridge et seraient intégrés à ces derniers. Sur cette base et considérant le principe économique que des actifs semblables devraient générer des rendements équivalents, il indique que Gazifère devrait avoir la même structure de capital, le même coût de la dette et le même taux de rendement qu'Enbridge.

[136] Il indique également que le coût de financement d'Enbridge est supérieur à celui d'EGD étant donné que c'est une société de gestion. Typiquement, une société de gestion a un coût de financement d'environ 25 points de base supérieur à la filiale d'exploitation. De plus, durant la crise financière, ce coût a augmenté étant donné que les sociétés de gestion comptent sur les dividendes de la filiale d'exploitation pour faire les paiements d'intérêts sur leur dette.

[137] Selon le D^r^ Booth, durant la crise financière, l'écart de financement entre celui d'Enbridge et celui d'EGD a augmenté significativement.

[138] Selon le D^r^ Booth, la réglementation des sociétés de services publics vise à limiter le pouvoir d'un monopole de fixer des prix élevés tout en rendant accessibles aux consommateurs les bénéfices normalement associés à la concurrence. Sur cette base, il indique qu'on ne devrait pas surprotéger les sociétés de services publics et ainsi empêcher les consommateurs de bénéficier des économies d'échelles que le statut de monopole

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27 Dossier R-3587-2005.

permet d'atteindre. Il donne l'exemple de la Commission de l'énergie de l'Ontario (CÉO) et des distributeurs d'électricité qu'elle réglemente pour appliquer ces principes.

[139] Le D$^{r}$ Booth précise qu'il ne faut pas établir le coût du capital selon le concept d'isolement mais plutôt établir ce coût sur une base de marché concurrentiel et ainsi laisser les forces du marché l'emporter.

[140] Il recommande que le coût de la dette soit le même que celui d'EGD, que le rendement sur l'avoir propre soit similaire à celui d'EGD et que la structure de capital soit laissée à 40 % de capitaux propres et à 60 % de capitaux empruntés.

[141] La Régie constate que les deux experts ont des points de vue nettement différents.

[142] La Régie a depuis longtemps établi le coût de la dette de Gazifère sur la base du principe d'isolement. La Régie juge que la preuve ne permet pas de modifier cette approche. **Néanmoins, considérant l'ampleur des écarts de crédit et leur volatilité, particulièrement pendant la crise financière, la Régie demande à Gazifère, pour le prochain dossier tarifaire, de déposer les documents suivants :**

- **la méthodologie et les modifications, le cas échéant, avec les explications, telles que présentées à la pièce B-11, GI-31, document 1.3;**
- **le rapport externe d'évaluation de la cote de crédit de Gazifère, tel que présenté à la pièce B-38, GI-30, document 4.1;**
- **les écarts de crédit d'Enbridge et d'EGD par rapport aux obligations du gouvernement du Canada, avec les dates des financements, le terme et le coupon, tels que présentés à la pièce B-11, GI-30, document 1.18, page 1.**

## 1.4 CONCLUSION

[143] La Régie doit, par sa loi constitutive, permettre un rendement raisonnable sur la base de tarification du distributeur. Dans le cadre de cet exercice, et tel que mentionné précédemment, la méthode que la Régie utilise relève de sa discrétion. À cet effet, l'arrêt Hope précise que c'est la résultante de l'exercice réglementaire qui doit rencontrer la norme de rendement raisonnable et non pas la méthode pour s'y rendre[28].

[144] La Régie retient, comme base première de référence, les résultats produits par le MÉAF. La Régie tient compte, de plus, des résultats des autres modèles aux fins de son appréciation du taux de rendement à octroyer à Gazifère.

[145] **La structure de capital n'ayant fait l'objet d'aucun débat, la Régie maintient la présente structure de capital composée de 40 % de capitaux propres et de 60 % de capitaux empruntés.**

[146] **Sur la base de la preuve au dossier et pour l'ensemble des motifs exprimés précédemment, la Régie fixe le taux de rendement sur l'avoir de l'actionnaire de Gazifère à 9,10 % pour l'année tarifaire 2011. Ce taux inclut un ajustement de 30 points de base pour tenir compte des effets de la crise financière. À partir de 2012, cet ajustement évoluera en fonction du deuxième membre de la nouvelle formule d'ajustement automatique qui sera, dès lors, en application.**

[147] **Sur la base d'un taux sans risque de 4,25 %, le taux de rendement autorisé de 9,10 % correspond à une prime de risque implicite de 4,85 % pour le distributeur.**

[148] **La Régie demande à Gazifère de mettre à jour, au plus tard le 10 décembre 2010 à 12 h, le taux de rendement de la base de tarification et le coût en capital prospectif. La Régie demande également à Gazifère de déposer, dans les futurs dossiers tarifaires, le calcul détaillé du coût en capital prospectif, tel que déposé dans le présent dossier[29].**

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[28] *Federal Power Commission* c. *Hope Natural Gas Company* 320 U.S. 591 (1944).

[29] Pièce B-11, GI-30, document 1, pages 18 et 19.

## 1.5 OPINION DU RÉGISSEUR RICHARD CARRIER EN CE QUI A TRAIT AU TAUX DE RENDEMENT

[149] Je présente, ci-après, les motifs qui sous-tendent ma conclusion quant au taux de rendement sur l'avoir de l'actionnaire à accorder à Gazifère pour l'année 2011. Bien qu'à plusieurs égards je retiens une conclusion similaire à celle de mes collègues, les motifs exprimés contiennent parfois des nuances, parfois des conclusions qui les distinguent. Ils forment donc un tout et doivent être lus comme tels. Enfin, je fais mien l'ensemble du résumé de la preuve, tel que présenté dans la décision majoritaire.

**Taux sans risque**

[150] Aux fins de la fixation d'un taux de rendement raisonnable pour l'année 2011, je retiens, dans le cadre de mon appréciation, un taux de 4,25 % comme point de référence pour les calculs afférents au MÉAF.

**Prime de risque du marché selon les données historiques**

[151] Il est utile, voire essentiel, de déterminer, dans un premier temps, les données de référence utilisées quant aux rendements sur l'équité observés sur les marchés et le contexte économique et financier dans lequel ces rendements ont été réalisés.

[152] Aux fins de mon appréciation des données historiques, je retiens la même approche que celle utilisée par la Régie dans ses décisions antérieures, soit le recours à des moyennes arithmétiques de longue période.

[153] Les données soumises en preuve par les deux experts permettent de situer la moyenne des rendements sur l'équité réalisés à 11,6 % au Canada et à 11,8 % aux États-Unis[30]. Les rendements moyens observés sur les obligations gouvernementales d'un terme de 30 ans ont été, pour leur part, de 6,4 % au Canada et de 5,7 % aux États-Unis. Il est à noter, par ailleurs, que les rendements réalisés l'ont été dans un contexte où l'inflation moyenne sur l'ensemble de la période était de 3,1 %.

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30 Preuve de Mme McShane, pièce B-1, GI-4, document 1, Schedule 6, page 2; preuve du D^r Booth, pièce C-2-13, Appendix B, Schedule 1 et Schedule 10.

**Tableau 2**

| **Données historiques sur les marchés** | **Can (1924-2009)** | **US (1926-2009)** |
|---|---|---|
| **Rendements sur l'équité (%)** | **11,60** | **11,80** |
| **Rendements des obligations de long terme (%)** | **6,40** | **5,70** |
| **Prime de risque du marché (%)** | **5,20** | **6,10** |
| **Inflation (%)** | **3,10** | **3,10** |

[154] Les données retenues sont représentatives des périodes de référence utilisées. D'autres résultats peuvent être obtenus en retenant d'autres périodes de référence ou en utilisant d'autres types de moyennes.

[155] Ces données sont utiles tant pour l'établissement de la prime de risque du marché dans le cadre du MÉAF que pour l'appréciation générale du caractère raisonnable des taux de rendement alloués aux entreprises réglementées. Ce sont des données objectives, établies à partir de statistiques fiables pour l'ensemble des secteurs de l'économie, lesquels, pour la plupart, sont en situation de concurrence sur les marchés. En ce sens, ces données historiques constituent un point de repère important pour évaluer le rendement attendu par les investisseurs dans le marché.

[156] L'établissement de la prime de risque du marché dans le cadre du MÉAF traditionnel repose sur l'estimation des rendements moyens observés sur des périodes suffisamment longues pour atténuer les effets reliés aux particularités des différents cycles économiques. Les périodes retenues ci-haut respectent ce critère.

[157] Tant Mme McShane que le D^r Booth mentionnent que la prime de risque du marché historique au Canada a été influencée artificiellement à la baisse par le niveau relativement élevé des taux obligataires canadiens pendant les années 80 et 90, lequel découlait du contexte budgétaire difficile du gouvernement canadien à l'époque. Ce phénomène n'a plus la même ampleur aujourd'hui. Aux fins de mon appréciation, je retiens, comme plage inférieure, une valeur de 5,5 % comme prime de risque du marché, calculée à partir des données historiques canadiennes.

[158] Comme plage supérieure de la prime de risque du marché basée sur des données historiques, je retiens, comme mes collègues, une valeur de 5,75 % basée sur les données historiques au Canada et aux États-Unis, bien qu'il soit également plausible de retenir une valeur de 6,0 % calculée uniquement à partir des données historiques américaines. Une telle valeur peut se justifier par le degré élevé d'intégration des économies canadienne et américaine et la très grande mobilité des capitaux.

[159] Aux fins de mon appréciation, je retiens la valeur supérieure de la fourchette établie. J'aborderai, dans une autre section, l'enjeu relatif à l'utilisation des seules données historiques comme estimateur du rendement attendu aujourd'hui et dans le futur par les investisseurs.

**Bêta brut (risque d'un distributeur repère)**

[160] Dans le cadre de l'application du MÉAF traditionnel, le risque d'un titre est évalué sur un plan statistique, en comparant l'écart type des rendements mensuels observés sur le marché pour une entreprise ou un secteur donné avec celui du marché en général. Ce paramètre, appelé bêta brut, est ensuite utilisé pour établir, à l'étape suivante, la prime de risque de ce secteur, en comparaison de celle du marché en général.

[161] Sur la base de la preuve, je juge approprié de retenir, dans le cadre de l'application de la formulation traditionnelle du MÉAF, la notion de bêta brut. Elle constitue une base relativement objective aux fins du calcul de la prime de risque. Selon la preuve au dossier, cette valeur peut être située dans une plage de 0,50 à 0,55.

[162] En ce qui a trait à l'utilisation de bêtas ajustés, je retiens la conclusion exprimée par la Régie dans ses décisions antérieures à l'effet que l'explication couramment utilisée dans les milieux de la recherche financière pour justifier un ajustement des bêtas bruts, soit la tendance observée sur le plan empirique pour les bêtas en général d'évoluer à terme vers la moyenne du marché qui est de un (1), ne peut être valablement retenue dans le cas d'une entreprise réglementée. En présence de droits exclusifs de distribution, il apparaît difficile de concevoir comment le risque propre à cette activité pourrait se modifier substantiellement à la hausse et évoluer vers le risque du marché au fil des ans.

[163] Ceci ne résout toutefois pas nécessairement de façon entière la problématique reliée à la qualité des bêtas bruts et à leur capacité à prédire correctement les rendements

réalisés dans le cadre de l'application du MÉAF. Il s'agit d'une question qui continue de susciter des débats entre experts.

**Prime de risque d'un distributeur repère**

[164] Sur la base des paramètres précédents, la prime de risque d'un distributeur repère peut être située dans une fourchette de 2,75 % à 3,16 %.

**Frais d'émission**

[165] Aux fins de mon appréciation, je juge approprié de retenir un coussin pour les coûts directs d'émission et escomptes non autrement compensés dans le calcul du revenu requis de l'entreprise réglementée. Ces coûts spécifiques seraient de l'ordre de 30 à 35 points de base selon l'examen détaillé effectué dans le dossier R-3690-2009.

[166] En ce qui a trait à une compensation pour les effets de dilution, à moins de preuve prépondérante à l'effet contraire, cet ajustement n'apparait pas nécessaire pour une entreprise réglementée. Sous l'hypothèse d'une structure de capital constante au fil des ans, et toutes autres choses étant égales par ailleurs, toute hausse du besoin total de financement par voie d'équité et de dette découle d'une hausse équivalente de la valeur de la base de tarification engagée aux fins de l'activité réglementée. Or, en pareil cas, le rendement total sur l'équité augmentera dans la même proportion que le rendement sur la base de tarification, ce qui devrait neutraliser entièrement, pour un investisseur le moindrement averti, toute crainte de dilution indue et ainsi maintenir la valeur des titres au marché intacte. Tel n'est pas nécessairement le cas pour les entreprises en situation de concurrence sur le marché qui peuvent émettre des titres à diverses fins autres que de financer des projets de croissance.

[167] La proposition de Mme McShane de prévoir une compensation suffisante afin de maintenir la valeur au marché des titres n'est pas retenue. Cette question s'apparente à celle discutée dans la décision D-2009-156[31], aux pages 54 à 58. Dans cette décision, la Régie n'a pas retenu la proposition d'établir le rendement de l'actionnaire sur la base d'une structure de capital reflétant les valeurs au marché plutôt que les valeurs aux livres.

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[31] Dossier R-3690-2009.

[168] Compte tenu de ce qui précède et de la preuve au dossier, je retiendrais, à titre de frais reliés aux émissions, une fourchette variant entre 30 et 50 points de base.

**Rendement d'un distributeur repère selon le MÉAF établi à partir de données historiques**

[169] Les données précédentes permettent d'établir un second point de référence utile dans l'appréciation du rendement à octroyer. Sur la base de l'application du MÉAF dans sa formulation traditionnelle et à partir de données historiques seulement, le taux de rendement d'un distributeur repère se situerait dans une fourchette de 7,30 % à 7,91 %.

[170] Un tel résultat doit toutefois être apprécié à la lumière du contexte économique et financier d'aujourd'hui. Les deux experts abordent les enjeux y reliés dans leur preuve respective. Les sections qui suivent portent sur ces questions.

**Ajustement - Prime de risque du distributeur repère (MEAF) et taux sans risque courant**

[171] Au présent dossier, Mme McShane soumet que le modèle « Prime de risque », tout comme les autres modèles utilisés pour établir un rendement raisonnable, sert d'abord et avant tout à déterminer le rendement attendu par les investisseurs aujourd'hui et dans le futur. En conséquence, selon elle, les données historiques sur la prime de risque pour les périodes passées doivent être appréciées en fonction de cet objectif et être ajustées au besoin lorsqu'elles ne sont pas suffisamment représentatives des conditions économiques et financières contemporaines et à venir.

[172] Elle soumet, entre autres, à l'appui de sa position que, pour la période d'après-guerre et sur la base des moyennes mobiles sur dix ans des périodes passées, il n'y a pas eu de tendance notable à la hausse ou à la baisse des rendements totaux sur l'équité observés entre 1947 et 2009, le rendement moyen pour la période se situant dans une plage de 11,5 % à 12,0 %. Elle juge donc cet estimé valable pour déterminer le rendement total du marché attendu aujourd'hui par les investisseurs. Comme la prévision 2011 du taux des obligations de 30 ans du gouvernement canadien est d'environ 4,7 % et la prévision à moyen et à long terme est de 5,25 %, elle en déduit une prime de risque du marché attendue par les investisseurs de l'ordre de 6,75 % alors que la moyenne historique de longue période pour le marché américain est de l'ordre de 6,1 %.

[173] Le Dr Booth soumet que la prime de risque se situe entre 5,0 % et 6,0 %, et ce, sur la base de l'ensemble de ses analyses, y incluant, à leur appui, l'examen des résultats du sondage du professeur Fernandez portant sur les approches généralement utilisées par les professeurs de finance, les analystes financiers et les dirigeants de sociétés.

[174] Comme mentionné par la Régie dans la décision D-2007-116[32], l'application du MÉAF soulève des difficultés particulières lorsque la fixation du taux de rendement intervient dans une période où les taux courants des obligations gouvernementales s'écartent de façon significative du taux moyen de longue période. La Régie s'exprimait de la façon suivante :

> « *Selon la Régie, l'application du modèle MÉAF présente une difficulté additionnelle lorsque l'évaluation du rendement intervient dans une période où les taux courants des obligations gouvernementales s'écartent de façon significative du taux moyen de longue période. La prime de risque étant calculée sur de longues périodes et représentant la différence entre la moyenne arithmétique des rendements du marché et de ceux des obligations gouvernementales, cette prime est donc fondamentalement représentative des conditions qui prévalaient sur cette même période. Un ajustement s'impose donc dans l'appréciation par la Régie lorsque les conditions du marché obligataire s'éloignent de cette moyenne.*
>
> [...]
>
> *La Régie considère qu'il s'agit d'un premier débat sur cette question qui mérite plus ample examen. Toutefois, ce débat ne saurait changer substantiellement le taux de rendement raisonnable auquel a droit l'actionnaire.*
>
> [...]
>
> ***Dans le présent dossier, la Régie apporte un ajustement à la hausse de 40 points de base des résultats produits par le MÉAF.*** »

[175] Dans la décision D-2009-156, la Régie apportait à nouveau un ajustement de même nature aux résultats produits par le MÉAF.

[176] La situation au présent dossier s'apparente à celle examinée dans ces dossiers et elle est même exacerbée par le fait que le taux sans risque est maintenant de l'ordre de 4,25 % alors qu'il se situait à 4,78 % en 2007. Il s'agit d'une situation relativement

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32 Dossier R-3630-2007, page 28.

nouvelle dans l'histoire récente, notamment depuis les années 2005-2006 alors que le taux sans risque est passé sous la barre des 5,0 %.

[177] La problématique en cause tire son origine du fait que, dans le cadre de l'application usuelle du MÉAF, la prime de risque d'un titre est ajoutée au rendement courant des obligations de long terme des gouvernements pour établir le rendement attendu par les investisseurs. La prémisse sous-jacente à ce modèle serait qu'il est raisonnable de supposer que les attentes des investisseurs et les rendements sur les marchés varient en parallèle avec l'évolution des taux des obligations gouvernementales ou taux sans risque. Cette prémisse serait toutefois discutable si les taux de rendement observés sur les marchés présentent plutôt une certaine stabilité ou constance dans le temps.

[178] Force est de constater que les deux experts ne partagent pas tout à fait le même point de vue quant à la stabilité des taux de rendement sur l'équité dans le temps. Mme McShane considère que les rendements nominaux sur l'équité sont stables dans le temps et, qu'en conséquence, la prime de risque attendue devrait être calculée en tenant compte de cette réalité et être établie en soustrayant de ces rendements observés les taux courants ou attendus des obligations gouvernementales. Selon la preuve du D^r^ Booth, ce seraient plutôt les rendements réels sur l'équité qui seraient constants et non les rendements en termes nominaux[33].

[179] L'analyse des données empiriques de Mme McShane, bien qu'utile, n'apparaît pas suffisamment documentée et robuste pour être utilisée directement.

[180] Par ailleurs, l'hypothèse d'une certaine stabilité des rendements dans le temps semble logique sur le plan conceptuel, l'investisseur recherchant, dans une perspective de moyen et de long terme, un rendement stable dans le temps, après prise en compte de l'inflation.

[181] Selon les données en preuve, l'écart entre les taux d'inflation historiques de 3,1 % et la projection pour le futur, qui est généralement de l'ordre de 2,0 %, est d'environ 100 points de base. Cette baisse est toutefois moins prononcée que la baisse observée d'environ 200 points de base du rendement des obligations gouvernementales, laquelle sert de référence pour l'application du MÉAF. Un tel résultat militerait en faveur d'un

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33 Pièce C-2-13, Appendix B, page 7.

ajustement de la prime de risque implicite si le rendement réel attendu par les investisseurs est stable dans le temps.

[182] La preuve au dossier ne permet pas de tirer des conclusions définitives relativement à cette problématique. Il s'agit d'une question d'ordre empirique qui pourrait faire l'objet d'un examen plus détaillé dans le futur.

[183] Par ailleurs, les deux experts reconnaissent que, pour la mise à jour du taux de rendement que la Régie autorisera au présent dossier, il est adéquat d'utiliser, pour les années futures, une formule d'ajustement de la prime de risque implicite lorsque les taux des obligations de long terme, ou taux sans risque, fluctueront à la hausse ou à la baisse. La divergence d'opinions à cet égard, si divergence il y a, porte surtout sur le niveau de cet ajustement, soit de 25 ou 50 points de base par 100 points de variation des taux obligataires de référence, plutôt que sur son fondement. Les deux experts reconnaissent ainsi, de ce point de vue, que la prime de risque implicite du distributeur varie effectivement en fonction du niveau des taux obligataires.

[184] Sur la base de la preuve au présent dossier et en tenant compte des décisions antérieures de la Régie, un ajustement de la prime de risque implicite d'un distributeur apparaît approprié lorsque les taux courants des obligations gouvernementales s'éloignent de façon notable de la moyenne historique utilisée pour le calcul de la prime de risque.

[185] Sur un plan pratique, la valeur de l'ajustement à retenir pour le taux de rendement de l'année 2011 peut être approximée, au présent dossier, en fonction d'un facteur d'élasticité représentant 25 % de l'écart entre le taux sans risque de longue période et le taux sans risque courant, soit le même facteur d'ajustement que celui de la formule d'ajustement automatique existante. L'ajustement retenu serait donc de l'ordre de 40 ou de 50 points de base selon que l'on réfère à l'écart entre, d'une part, la moyenne historique des taux sans risque au Canada ou aux États-Unis et, d'autre part, le taux sans risque courant de 4,25 %.

**Les écarts de crédit courants**

[186] Dans le cadre de son analyse quant à l'établissement d'un taux de rendement raisonnable, le D[r] Booth recommande un ajustement de 50 points de base pour tenir compte du fait que les effets de la crise financière sont encore présents. Il note la persistance d'un degré élevé de nervosité sur les marchés financiers. Il mentionne

également que les écarts de crédit se sont amplifiés entre le moment du dépôt de sa preuve et l'audience.

[187] Mme McShane est d'avis que, pour l'essentiel, la crise financière est derrière nous. Cependant, elle mentionne que la problématique fondamentale de la formule d'ajustement et les résultats qu'elle a produits par le passé au Canada n'étaient pas reliés à la crise financière. Cette problématique était préexistante et n'a été qu'exacerbée par la crise. Selon elle, la problématique demeure donc entière. Ses recommandations quant au taux de rendement sur l'avoir de l'actionnaire et à la formule d'ajustement tiennent compte de cette constatation.

[188] La question des écarts de crédit et son lien avec l'établissement d'un taux de rendement raisonnable sur l'avoir de l'actionnaire ont fait l'objet de débats répétés devant la Régie depuis 2007. La Régie notait l'insuffisance de la preuve à cet égard dans sa décision D-2008-140[34]. Par ailleurs, dans sa décision D-2009-156, la Régie retenait, à titre d'ajustement pour compenser les effets de la crise, un ajustement de la prime de risque et du taux de rendement applicable au distributeur se situant dans une plage variant entre 0,25 % et 0,55 %.

[189] Au présent dossier, il peut être constaté que les écarts de crédit sont encore à un niveau supérieur à leur moyenne historique. Les soubresauts observés sur les marchés financiers en 2009, en lien avec la problématique des déficits budgétaires et des dettes souveraines en Europe, illustrent également la relative fragilité des marchés au sortir de la pire crise financière depuis les années 1930.

[190] Selon la preuve au dossier, les écarts de crédit demeurent élevés. Il est plausible qu'ils persistent et qu'ils demeurent volatils pour une durée relativement longue.

[191] Tous les experts s'entendent pour dire que le rendement sur l'avoir propre devrait, dans des circonstances normales, être plus élevé que le rendement sur les titres obligataires, en raison du risque plus élevé que les actionnaires assument par rapport aux détenteurs d'obligations corporatives. Il est aussi généralement admis que les écarts de crédit peuvent fluctuer au cours des différentes phases d'un cycle économique.

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34 Dossier R-3662-2008 Phase 2.

[192] Sur la base de la preuve au dossier, un ajustement de la prime de risque établie dans le cadre du MÉAF apparaît justifié.

[193] À cet égard, il y a lieu de prendre en compte le niveau des écarts de crédit observé au moment de l'audience, soit d'environ 1,50 % selon l'indice Bloomberg, représentant les écarts entre le rendement des obligations de long terme des sociétés réglementées et celui des obligations gouvernementales de même durée. Par rapport à la moyenne historique de 0,90 % pour ce même indice selon la preuve du D$^{r}$ Booth, l'écart serait de l'ordre de 60 points de base.

[194] En ce qui a trait au quantum de l'ajustement à retenir, la partie inférieure de cette plage peut être établie sur la base du facteur d'élasticité proposé par les experts pour cette même variable dans le cadre de la discussion sur les formules d'ajustement à retenir dans le futur, soit 50 % de l'écart observé ou 30 points de base. La partie supérieure de cette plage peut être fixée à 100 % de l'écart, soit 60 points de base.

[195] Sur la base de la preuve au présent dossier, notamment quant au contexte financier, je retiens, aux fins de mon appréciation, un ajustement de l'ordre de 40 à 50 points de base.

**Distributeur repère selon le MÉAF ajusté**

[196] Sur la base de ce qui précède, le taux de rendement d'un distributeur repère selon l'approche d'un MÉAF ajusté peut s'établir dans une fourchette variant entre 8,0 % et 9,01 %.

**Les autres modèles et autres considérations**

[197] Mme McShane présente les résultats découlant de l'utilisation de divers autres modèles ou variantes de ces modèles. Certaines difficultés surgissent aux fins de l'interprétation de ceux-ci.

[198] Ces difficultés portent, notamment, sur les effets reliés au phénomène de circularité, soit le fait de se baser directement ou indirectement sur les résultats des entreprises réglementées ou sur les valeurs au marché pour établir le rendement attendu

par les investisseurs, alors que ces mêmes résultats dépendent de façon plus ou moins étroite des décisions passées des régulateurs.

[199] Ces difficultés portent également sur la qualité de l'échantillon retenu, notamment quant au degré de risque supporté par les entreprises américaines composant l'échantillon comparativement au risque moyen d'un distributeur repère au Canada.

[200] Mme McShane conclut à l'inexistence d'un tel écart. Elle soutient que les environnements réglementaires, économiques et financiers au Canada et aux États-Unis sont sensiblement les mêmes.

[201] Le Dr Booth soutient que le différentiel de risque peut justifier un écart de 90 à 100 points de base pour un distributeur réglementé aux États-Unis. Il s'appuie, entre autres, sur les résultats de l'analyse de Moody's d'août 2009, laquelle mentionne le caractère généralement plus prévisible et plus favorable à l'environnement réglementaire au Canada.

[202] La preuve du Dr Booth concernant l'analyse de Moody's est utile puisqu'il s'agit de l'analyse d'une tierce partie spécialisée dans la notation des titres des sociétés réglementées. Une preuve et un examen encore plus poussé des paramètres considérés par ces agences de notation apparaissent être une piste utile à explorer pour le futur.

[203] Au-delà des remarques souvent générales soumises par les experts, l'importance de cet enjeu aux fins de la détermination d'un rendement raisonnable pour l'investisseur justifie que des efforts plus grands soient déployés pour comparer les risques encourus par les entreprises réglementées au Canada et aux États-Unis, mais idéalement aussi par rapport aux autres secteurs d'activité économique où les entreprises sont soumises à la concurrence en retenant, par exemple, un secteur d'activité dont le facteur bêta serait égal à celui du marché.

[204] À cette fin, il serait utile de pousser l'analyse des régimes réglementaires, par exemple, en comparant le traitement applicable aux risques reliés aux contrats d'approvisionnement et de transport, les règles applicables aux erreurs de prévision, les règles en matière d'autorisation des projets d'investissement selon que les autorisations sont données a priori ou a posteriori, les règles applicables pour l'acquisition et la disposition des actifs excédentaires ou devenus désuets, et ce, au vu de la jurisprudence applicable.

**Prime de risque d'un distributeur repère selon l'historique de rendement des sociétés réglementées**

[205] Dans le cadre de cette approche, Mme McShane obtient une prime de risque historique de 11,0 % pour les sociétés réglementées aux États-Unis (1947-2009) et au Canada (1956-2009). Cette méthode a l'avantage d'être simple d'application. Elle soulève cependant plusieurs difficultés dans l'interprétation des résultats.

[206] Les données canadiennes reflètent une période au cours de laquelle les taux obligataires de long terme étaient très élevés. Dans la mesure où les rendements autorisés tenaient compte de cette réalité, les résultats obtenus à l'aide de cette approche portent sur une période possiblement peu représentative du contexte économique actuel.

[207] Quant aux données américaines, le phénomène de la représentativité de l'échantillon en termes de risque et l'impact relié au choix de la période de référence doivent être pris en considération.

**Prime de risque d'un distributeur repère selon l'approche d'actualisation des flux monétaires (AFM) des entreprises réglementées**

[208] Mme McShane obtient une prime de risque de 9,4 % à l'aide de ce modèle avant frais d'émission comparativement à 9,25 % avec son estimation du MÉAF. Les particularités propres au modèle AFM sont abordées aux paragraphes qui suivent.

**Rendement d'un distributeur repère selon le modèle d'actualisation des flux monétaires (AFM)**

[209] Mme McShane présente diverses variantes de ce modèle. Elle mentionne qu'il s'agit d'une alternative au MÉAF largement utilisée et que ce modèle est le principal modèle utilisé par les régulateurs aux États-Unis.

[210] Le modèle repose sur l'estimation des flux monétaires futurs qui seront constitués des dividendes versés par l'entreprise et l'actualisation de l'ensemble de ces flux en dollars d'aujourd'hui. À l'aide de ce modèle, Mme McShane estime le rendement d'un distributeur repère, avant frais d'émission, à 10,0 %.

[211] La spécification des paramètres du modèle AFM est particulièrement importante. Dans sa formulation de base, ce modèle exige que soient estimés les flux des dividendes de la société évaluée ou de l'échantillon pour chacune des années dans le futur et d'actualiser ces flux en dollars d'aujourd'hui. Les difficultés reliées à une estimation correcte de la croissance des dividendes par action « g » ne sont pas négligeables. Un changement mineur de cette variable peut causer un impact important du fait que, dans le cadre de ce modèle, l'actualisation des données porte sur l'ensemble des périodes futures, théoriquement jusqu'à l'infini.

[212] Mme McShane utilise, dans un premier temps, les projections des analystes financiers pour établir la valeur du paramètre « g ». Elle utilise également ses propres estimations d'un taux de croissance soutenable à long terme. Le Dr Booth conteste les diverses hypothèses de Mme McShane. Il soumet, entre autres, que l'utilisation des prévisions des analystes financiers fait l'objet d'une grande controverse en raison du caractère trop optimiste de leurs prévisions, tel qu'il a pu être observé de temps à autre dans le passé.

[213] Bien qu'étant en désaccord avec cette hypothèse, Mme McShane soumet que dans la mesure où les investisseurs croient ces prévisions et les intègrent dans leurs décisions, les résultats du modèle AFM constituent un estimé non biaisé des attentes des investisseurs[35]. Une telle conclusion apparaît discutable. Dans le marché privé non réglementé, l'investisseur sera sanctionné par le marché si ses décisions sont basées sur des prévisions d'analystes qui s'avèreraient, en moyenne, trop optimistes. À l'inverse, si les régulateurs devaient baser leurs décisions sur les mêmes prévisions en moyenne trop optimistes des analystes, ce biais serait alors introduit dans les tarifs sans sanction possible par le marché. En pareil cas, un rendement biaisé à la hausse serait réalisé par l'actionnaire au détriment des usagers qui devraient acquitter une facture plus élevée que nécessaire.

[214] Aux fins de l'utilisation des résultats de ce modèle, une preuve détaillée et suffisamment rigoureuse de la détermination de la variable de croissance « g » s'avère donc nécessaire. Les prévisions des analystes auxquelles il est fait référence ne pouvant être testées directement en audience, il est difficile de statuer sur le caractère raisonnable des estimés produits. De plus, l'hypothèse selon laquelle le facteur de croissance des dividendes peut être présumé égal à celui de la croissance nominale de l'économie ne

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[35] Preuve de Mme McShane, pièce B-1, GI-4, document 1, page 57.

repose pas sur une évaluation détaillée et spécifique au présent dossier, mais sur une approche qui serait couramment utilisée dans le milieu financier. Comme ces diverses hypothèses sont déterminantes quant aux résultats de ce modèle, une preuve plus élaborée devrait être produite à cet égard.

**Conclusion sur les autres modèles et autres considérations**

[215] Pour l'ensemble de ces considérations, les résultats produits par les autres modèles sont utilisés au présent dossier mais leur utilité aux fins de la détermination d'un taux de rendement raisonnable est limitée.

[216] Même s'il est préférable, notamment dans un contexte comme celui qui prévaut actuellement, de pouvoir baser la détermination du taux de rendement de l'actionnaire sur un large éventail d'approches, je conclus, comme mes collègues, que l'utilisation du MÉAF apparaît, au présent dossier, l'approche de référence la plus fiable.

[217] Globalement, considérant le fait qu'aucun modèle ne peut représenter complètement et correctement à lui seul les attentes des investisseurs, un ajustement variant entre 10 et 50 points de base de la fourchette des résultats produits par le MÉAF peut être retenu.

[218] Aux fins de mon appréciation, considérant l'ensemble des motifs exprimés, je retiens la partie inférieure de la plage ainsi établie.

**Taux de rendement d'un distributeur repère**

[219] Sur la base de ce qui précède, le taux de rendement établi pour un distributeur repère, incluant les frais d'émission, peut être situé dans une fourchette variant entre 8,10 % et 9,51 %. Ce résultat sert de guide dans l'appréciation du rendement à octroyer à Gazifère.

**Risque additionnel de Gazifère**

[220] Aux fins de l'établissement du rendement de Gazifère, je juge l'ajustement proposé par Mme McShane raisonnable.

## Tableau 3
## Fourchette d'un rendement raisonnable sur l'avoir de l'actionnaire pour Gazifère selon l'opinion minoritaire

| | Bas | Haut |
|---|---|---|
| *MÉAF* | % | % |
| **1) Taux sans risque** | **4,25** | **4,25** |
| **2) Prime risque marché (moyennes arithmétiques/données historiques)** | 5,50 | 5,75 |
| ***3) Bêta brut (marché = 1,00)*** | *0,50* | *0,55* |
| **4) Prime risque distributeur repère (4 = 3*2)** | **2,75** | **3,16** |
| **5) Frais émission** | **0,30** | **0,50** |
| **6) Sous-total: distributeur repère selon MÉAF avant ajustement** | **7,30** | **7,91** |
| **7) Prime de risque du distributeur repère et taux sans risque courant** | **0,40** | **0,50** |
| **8) Prime de risque du distributeur repère et écarts de crédit courants** | **0,30** | **0,60** |
| **9) Sous-total: distributeur repère selon MÉAF ajusté** | **8,00** | **9,01** |
| *Autres modèles* | | |
| **10) Autres modèles et autres considérations** | **0,10** | **0,50** |
| *Distributeur repère* | | |
| **11) Sous-total: distributeur repère** | **8,10** | **9,51** |
| *Gazifère* | | |
| **12) Risque additionnel GI** | **0,50** | **0,50** |
| **13) Total Gazifère (13=11+12)** | **8,60** | **10,01** |

[227] Pour l'ensemble des motifs exprimés dans mon opinion, les décisions antérieures de la Régie et le contexte dans lequel évolue le distributeur, je fixerais le rendement raisonnable sur l'avoir de l'actionnaire de Gazifère à 9,40 %.

**Formule d'ajustement**

[228] Mme McShane propose une nouvelle formule d'ajustement du taux de rendement comportant un facteur d'élasticité inverse de 0,50 pour toute variation future du taux sans risque ainsi qu'un facteur d'élasticité de 0,50 pour toute variation future des écarts de crédit corporatif.

[229] Le D^r Booth propose une formule identique, à l'exception du facteur d'élasticité du taux sans risque qui serait maintenu à 0,75 comme dans la formule existante.

[230] La proposition de Mme McShane est basée sur deux tests. Le premier utilise les rendements alloués par les régulateurs aux États-Unis entre 1995 et 2009 aux fins d'établir les facteurs d'élasticité. Le second test utilise les résultats de la méthode prime de risque établis à l'aide du modèle AFM.

[231] Ces deux tests sont basés sur l'utilisation directe ou indirecte de données provenant du secteur réglementé et s'appuient sur des données américaines. Ceci explique possiblement pourquoi les résultats de la formule proposée reproduisent de plus près l'évolution des rendements alloués aux États-Unis plutôt que celle des rendements alloués au Canada au cours de la période étudiée.

[232] À cet égard, la disponibilité de données et d'analyses portant sur l'élasticité des rendements sur l'équité en lien avec le taux sans risque et les écarts de crédit, mais portant sur des secteurs d'activité autres que les secteurs réglementés, serait possiblement utile.

[233] Par ailleurs, le Dr Booth est d'accord, de façon subsidiaire, avec l'introduction dans la formule d'ajustement d'un second terme représentant l'élasticité de la prime de risque implicite avec l'évolution des écarts de crédit corporatif.

[234] Comme mes collègues, je conclus qu'il est justifié de retenir un tel ajustement à partir de l'exercice 2012. Ceci permettra un ajustement plus rapide de la prime de risque implicite du distributeur en cas de variation substantielle des écarts de crédit dans le futur.

**DECISION**

**IN THE MATTER of** a review of
the Cost of Capital for Enbridge Gas
New Brunswick L.P. (EGNB)
**November 30, 2010**

NEW BRUNSWICK ENERGY AND UTILITIES BOARD

**Return on Equity**

EGNB's current approved rate of return on equity (ROE) is 13%, which was approved by the Board in its June 23, 2000 decision. EGNB proposes that the ROE be set at 12.75% while the Public Intervenor proposes that the ROE be 9%. The Public Intervenor's proposal is supported by Atlantic Wallboard Limited and Flakeboard LP.

The Board was presented with a number of different methods for calculating an appropriate ROE. Kathleen McShane, who testified on behalf of EGNB, uses three, namely; comparable earnings, discounted cash flow and equity risk premium. Of these methods, the Board finds that the first two methods are not appropriate for the circumstance of the present case and will deal only with the equity risk premium method.

With respect to the equity risk premium, Ms. McShane uses different tests. These tests are the capital asset pricing model (CAPM), a discounted cash flow equity premium method and the historical premium method. Ms. McShane averages the premiums resulting from these three tests to establish a recommended premium and resulting ROE for a benchmark utility.

Both Ms. McShane and Dr. Booth use CAPM in their methodolgy. Dr. Booth's evidence is primarily based on the CAPM method while Ms. McShane uses it as one of a series of approaches. Ms. McShane expresses concerns about solely using the CAPM method but the Board believes the CAPM method's advantages outweigh its weaknesses. This is particularly true with respect to EGNB - a small, young utility which is not publicly traded.

The National Energy Board discussed the CAPM method in the decision of *Trans Quebec & Maritimes Pipelines Inc., [RH-1-2008]* where it stated at page 26:

> *The Board is of the view that CAPM is widely accepted as a cost of equity model. This model has been relied upon by the Board in previous proceedings and was not contested in this proceeding as a method to estimate the cost of equity. In the Board's view, CAPM captures the risk equity holders have to bear when holding a common stock.*

The Board finds the CAPM method is widely used, well accepted and thoroughly vetted. As a result the Board finds that, at this time, a Capital Asset Pricing Model is an appropriate method to determine the ROE for a benchmark utility and will use this method in this decision.

This CAPM method for EGNB can be summarized by the following equation:

ROE = Risk free rate + (Market Risk premium x beta coefficient) + Flotation costs + EGNB risk premium

As the equation indicates the model requires the determination of a reasonable forecast of the risk free rate. An appropriate market risk premium is then added to the risk free rate. The premium is estimated for the market as a whole and adjusted by a beta coefficient. The beta is a factor used to convert a general market risk premium into one appropriate for a benchmark utility. An additional amount is added to cover flotation or financing costs. Since EGNB is not a mature benchmark utility, a further risk premium must be considered to account for EGNB's specific situation. This decision will address each of these matters in turn.

**The Risk Free Rate**

The initial step in the CAPM method establishes the risk free rate. Both Ms. McShane and Dr. Booth recommend that the 30-year Government of Canada Bond interest rate (LTC) be used as the risk free rate. The Board accepts this recommendation for the purposes of this hearing.

Ms. McShane recommends an LTC forecast of 5.0% based on the *Consensus Economics* forecast. *Consensus Economics* does not produce monthly forecasts of the 30-year Government of Canada bond. Accordingly Ms. McShane uses their forecast for a 10-year Government of Canada bond, to which she adds a differential between the 10-year bond rate and the 30-year bond rate. In the first year of her forecast projection she adds a premium of 0.4% representing the current differential to arrive at 4.6%. Ms. McShane's forecast projection is for ten years, and consequentially she uses the same methodology to develop LTC forecasts for 2011-2015 (5.0%) and 2016-2020 (5.3%). She concludes that an LTC of 5.0% is reasonable.

Dr. Booth's LTC forecast is based on the recent history of the 30-year bond rate. He concludes that the 30-year bond yield stayed at 4.5% from 2005 to the end of 2007. It is his opinion that over the long term the rate will return to 4.5%. He forecasts a modest economic recovery in

Canada which will increase the interest rate and therefore forecasts an LTC rate of 4.25% in 2011 and 4.5% in 2012. He recommends that the Board use an LTC rate of 4.25%.

The Board finds that forecasts of LTC from *Consensus Economics* are widely accepted and more appropriate than historical yields and will use them in establishing the risk free rate. The Board does not believe a 10-year projection of LTC is appropriate, but otherwise agrees with Ms. McShane's approach.

In the Board's view the preferred approach, at this time, is to use the *Consensus Economics* forecast for 10-year bonds and add the current rate differential between 10-year bonds and 30-year bonds to arrive at a forecast for the 30-year Government of Canada Bond rate as the LTC. The Board, following this approach, finds that the risk free rate is 4.6% for the purposes of this decision.

**Market Risk Premium**

Once a risk-free rate has been determined, the next step is to determine the market risk premium which approximates the added return required by investors in the equity market.

To calculate the premium for the market as a whole, Ms. McShane subtracts her LTC forecast from historical equity returns. She examines historical data and concludes that the ROE has been in the range of 11.5% to 12.0%. After using statistical techniques, Ms. McShane testified that there is no discernable trend in the ROE and she concludes that this range is a reasonable prediction of the market returns in the future. She subtracts from this range her forecast of LTC of 5.0% and concludes that a reasonable range for the market risk premium is 6.5% to 7.0%. She recommends a middle value of 6.75%.

The Board finds a more appropriate comparison is between the historical LTC rates and the historical return on equities. This comparison is provided by Ms. McShane in Schedule 14 and summarised in Table 6 of her evidence. The data suggests the average market risk premium for Canadian Companies was 5.3% for the time period between 1924 and 2009.

Dr. Booth's recommendation for a market based premium relies on a survey of financial analysts and finance professors on the market risk premiums they use. Specifically, his evidence includes a 2008 survey of academics that includes 29 Canadians and that these respondents indicated premiums that ranged from 2.0% to 8.0%. Dr. Booth observes that most of the respondents in the survey use a premium of 5.0% to 6.0% and he recommends this range as appropriate.

Having considered all the evidence the Board finds that an appropriate market risk premium lies between 5.0% and 6.0% and for the purposes of this decision, the Board sets the market risk premium at 5.5%.

**Beta**

To arrive at the risk premium for a benchmark utility, the market risk premium for the market as a whole must be adjusted using a beta coefficient. This is because an investment in a typical utility is considered less risky than an investment in the market as a whole.

Ms. McShane recommends a beta in the range of 0.65 to 0.70. She arrives at this range by analyzing the historical variability of the S&P/TSX Composite Index compared to a sub-index of utility companies as a whole.

Dr. Booth also employs historical data. He examines beta from the utilities S&P/TSX sub-Index as well as a set of Canadian utility holding companies. He also examines the performance of utilities in the recent financial crisis. He concludes that a reasonable range for beta is 0.45 to 0.55.

By its nature the utility beta is based on information that is similar across the country. For this reason there is value in the Board looking at other jurisdictions for additional information. A partial review of other jurisdictions is found in Dr. Booth's evidence on page 50. The range would appear to be from 0.50 to 0.66.

The Board finds that the appropriate beta for the purposes of this decision is 0.55 and that the resulting market premium for a benchmark utility is 3.03% (5.5% x 0.55).

**Flotation Costs**

The Board heard evidence from both Ms. McShane and Dr. Booth that a premium to account for financing or flotation costs is appropriate. Ms. McShane recommends the premium be 0.75% while Dr. Booth concludes that 0.50% is reasonable.

Very little compelling evidence on this topic was provided to the Board and little time at the hearing was spent on this matter. As both experts indicate an amount for flotation costs is necessary, the Board accepts Dr. Booth's proposal, being the lower of the two, and finds that a premium of 0.50% is appropriate.

**Benchmark ROE**

The above findings result in an ROE for a benchmark utility of 8.13%.

**Specific Risk Premium for EGNB**

EGNB is not a benchmark utility and the final ROE calculation must include a risk premium for investors specific to EGNB. Ms. McShane recommends an EGNB risk premium of 2.0% to 3.0% while Dr. Booth concludes that no more than 1.0% is required.

It is useful at this point to discuss the risk exposure related to EGNB.

In its evidence EGNB groups the risks it faces into five categories: market risk, competitive risk, supply risk, regulatory risk and deferral account recovery risk. While EGNB states that the risk in some of these categories may have decreased, it submits that the risk in others has increased. Taken as a whole, EGNB believes it still faces significant risks and that the risks have shifted from market development to the return of capital invested. Before examining the risks associated with the EGNB's business, the Board feels it is important to clarify the role these risks play in coming to a conclusion.

The Board agrees that the magnitude of the risks have shifted from market development to a concern about the return of invested capital. However, there is a need for caution when comparing the current risk with the risk associated with the company in 2000. These sort of relative changes in risk from 2000 to the present may help guide the Board in its decision but the main comparison must be with other currently operating utilities. The ROE is an incentive to the investor looking to invest in equities. The investor's choice is not whether to invest in EGNB today or back in 2000, but rather whether to invest in EGNB today compared to other investment opportunities, including other utilities. It is with this frame of reference that the Board evaluates the risk facing EGNB and determines the risk premium required.

Market Risk

In terms of market risk, EGNB includes the size and nature of the New Brunswick market as an issue. Specifically, it claims cost-effectively serving customers is more challenging in a sparsely populated province. Moreover, because New Brunswick's economy is small and not as diverse as other provincial economies, New Brunswick is more susceptible to economic downturns. This susceptibility to economic fluctuations, the company maintains, puts the utility at a greater risk of losing load. EGNB also includes the existence of Single End-use Franchises which it estimates represents as much as 80% of the provincial load. Without this load the company believes it is exposed to greater risk than it would be otherwise.

Additionally, in its evidence, EGNB states that natural gas is still a relatively unfamiliar fuel choice although the company has made progress in educating potential customers about this option.

The Board is well aware of the nature of the customer base, the provincial economy and the Single End-Use Franchises. The Board, however, is not convinced that these factors have changed in any significant way since 2000.

Competitive Risk

With respect to competitive risk, EGNB states that its ability to grow its market is largely dependent on the price of competing fuels. The ability to attract new customers is – in part - based on being able to offer a savings at the burner tip compared to the price of alternative fuels. Inherent in this business model is that, if the price of the fuels gets too close together, it will be harder to attract new customers. The Board heard testimony that this convergence of fuel prices did occur. Natural gas prices rose significantly during the early years of the franchise reducing the competitive advantage relative to both oil and electricity. In addition electricity prices did not rise as the company forecasted. The combination of these factors decreased the incentive to convert to natural gas.

As a result of the reduced incentive, EGNB is more dependent on potential customers deciding to install new furnace equipment before they switch to natural gas. The company stated that it has made progress capturing roughly 45% of new residential construction and 90% of new commercial construction in areas it serves.

It is important to understand the nature of the risk that is being considered. EGNB's business model is dependent on market prices that are inherently volatile or unpredictable. That this unpredictability is more than EGNB forecasted is related to forecasting error rather than an increased risk.

Supply Risk

EGNB testified the company has greater risk in relation to the supply of natural gas itself. The company notes that production over the long-term from the Sable Offshore Energy Project, the region's main supply source, remains unproven. The Board heard that the risk is not that the company will not be able to supply natural gas to its customers; but rather that the cost of supply from New England or the Canaport LNG facility in Saint John will make heating with natural gas less competitive. Unlike other natural gas utilities EGNB's distribution rates incorporate the cost of the natural gas in a manner that can reduce revenues if natural gas prices increase. The Board notes that there have been both positive and negative developments regarding the gas supply and concludes that, on balance, these changes have not impacted on EGNB's overall risk

Regulatory Risk

EGNB argued that the utility's risk related to regulation has increased. The Board heard testimony that recent decisions have increased the uncertainty related to the company and therefore increased the business risk. Specifically EGNB stated that when the Board determined that the capital structure and the return on equity could change during the Development Period, it increased the risk of lower returns.

While the future of the company will be influenced by the decisions in the last year and in the coming years, these decisions are part of the regulatory regime established at the beginning of the franchise, and cannot be seen to increase the risk to a regulated enterprise such as EGNB.

The Board heard testimony about other risks. The Public Intervenor and others noted that when the franchise began, the company had no customers, no infrastructure and no revenue source.

Ten years later there are in excess of 10,000 customers who purchase more than 5 terrajoules of natural gas. The Public Intervenor suggested that this is a large reduction of risk to the utility.

Atlantic Wallboard L.P. (AWL) also argued that the risk facing the company has decreased. The Board heard that in 2000, the company was facing an application by a competitor for a franchise in Moncton. By its own documents, such a franchise would have made the EGNB operation unviable. Additionally, AWL stated that when the franchise was first granted, EGNB could not market the gas but was required to rely on third parties to sell the commodity. This left EGNB, in part, subject to the marketing efforts of third parties. AWL argued that both of these risks are gone. The application for an alternative franchise was unsuccessful and, in 2003, the legislation was amended to allow EGNB to sell gas directly to customers.

Deferral Account Risk

The risks discussed above have largely remained stable or decreased over the last ten years. What truly separates EGNB from mature utilities and what makes EGNB much more risky than a mature utility is its large and growing deferral account.

The Deferral Account was original forecast to peak at $13 million and has ballooned in the last ten years. At the end of 2009, the account was estimated at $155 million and EGNB predicts that this account will peak at $173 Million in 2011. EGNB's total regulatory deferral, which includes Operating and Maintenance costs related to the development of the system, is expected to be in excess of $276 million at that time.

The Board finds that the risk that not all of the Deferral Account will be recovered is a real and significant risk facing EGNB's investors. Not only is the size of the debt to be paid large but EGNB's ability to recover it is dependent on market forces which are out of EGNB's control.

The EGNB risk premium must give the investor a return in exchange for the risk relative to other investment options. Too much of a premium, in the case of this utility, imposes undue costs on future customers; too little risk may starve the utility of needed capital. In this respect the most important risk to consider is the added risk that the deferral account may not be fully recovered. Considering all of the evidence and risk factors and particularly the magnitude of the Deferral Account the Board finds that the EGNB risk premium is 2.75%.

Summary

As a result the appropriate return on equity is 10.9%. The calculation is summarized in Table 1.

TABLE 1: Return on Equity Calculation

| | | | |
|---|---|---|---|
| 1 | Risk Free Rate | | 4.6 |
| 2 | Market Risk Premium | | 5.5 |
| 3 | Beta | | 0.55 |
| 4 | Utility Risk Premium | Line 2 x line 3 | 3.03 |
| 5 | Floatation Cost | | 0.5 |
| 6 | Benchmark Utility | Line 1+Line4+Line 5 | 8.13 |
| 7 | EGNB Risk | | 2.75 |
| 8 | ROE | Line 6 + Line 7 | 10.9 |

**Capital Structure**

The capital structure of a business includes both the debt and equity. The debt-to-equity ratio caps the percentage of the equity on which the EGNB may earn a ROE. In its June 2000 decision the Board approved, for regulatory purposes, the use of a capital structure for EGNB with an equity component not to exceed 50%.

In the current hearing EGNB proposed that the debt-to-equity ratio remain unchanged. Ms. McShane testified that the equity share in Canadian utilities has increased since the franchise was granted. She testified that this trend supports EGNB's position that the equity portion not be lowered.

In his pre-filed evidence Dr. Booth states on the first page:

> *I would recommend that EGNB be immediately moved to the 40% common equity ratio the company is forecasting for 2016. This is slightly higher than the common equity ratios of the large mature gas LDCs, like its sister company EGDI in Ontario, but reasonable given its size.*

No party filed evidence of another utility that currently has an approved equity component as high as 50%. Table 2 of Ms. McShane's evidence set out the level of equity percentages for Canadian natural gas utilities. This equity level ranged from 36% to 45% for 2010. Mature natural gas utilities tended to fall in the 36% to 40% range. For example Enbridge Gas Distribution Inc. is at 36%. EGNB is not a mature utility, but it has moved toward maturity since 2000. This movement should be reflected in the debt-to-equity ratio.

Considering all the factors and evidence before it, the Board determines that EGNB should have a capital structure where the equity portion does not exceed 45%.

**EB-2010-0018**

**IN THE MATTER OF** the *Ontario Energy Board Act 1998*, S.O.1998, c.15, (Schedule B);

**AND IN THE MATTER OF** an Application by Natural Resource Gas Limited for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing October 1, 2010.

**BEFORE:** Ken Quesnelle
Presiding Member

Paul Sommerville
Board Member

## DECISION AND ORDER

Natural Resource Gas Limited ("NRG" or the "Applicant"), filed an application dated February 10, 2010 with the Ontario Energy Board under section 36 of the *Ontario Energy Board Act*, *1998,* S.O. c.15, for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas for the 2011 fiscal year, commencing October 1, 2010.

NRG is a privately owned utility that sells and distributes natural gas within Southern Ontario. The utility supplies natural gas to Aylmer and surrounding areas to approximately 7,000 customers, with its service territory stretching from south of Highway 401 to the shores of Lake Erie, from Port Bruce to Clear Creek.

## COST OF CAPITAL

### Capital Structure and Return on Equity

NRG requested a deemed capital structure of 58% debt and 42% equity with a return on equity ("ROE") of 50 basis points over the Board determined ROE as per the Board's Cost of Capital Parameter Updates issued on February 24, 2010. In requesting a 42% equity ratio NRG relied on the opinion of its expert Ms. Kathleen McShane who indicated that the 42% ratio adopted by the Board in 2006 and a premium of 50 basis points over the Board determined ROE remains appropriate for NRG.

All intervenors including Board staff made submissions on the proposed capital structure and ROE. Board staff, VECC and IGPC submitted that the actual capital structure of NRG was essentially unstable and there were several methods of calculating the capital structure if factors such as gross (excluding the impact of compensating balance) versus net (including the impact of compensating balance) and the retraction provision of shares was considered.

Board staff submitted that the main reason that NRG received 42% equity ratio in the 2006 Decision (EB-2005-0544) was because that was the actual ratio and Ms. McShane's evidence was that the actual was the most appropriate value to use. The current actual capital ratio of NRG was 37% as indicated in the technical conference[8]. Board staff further referred to a table[9] in Ms. McShane's report that showed a majority of the utilities operated pursuant to a 40% deemed equity ratio.

IGPC submitted that since 2006 NRG had made no equity contribution and had added over $4.5 million to the rate base related to the IGPC pipeline. Notwithstanding this, NRG persisted in its claim for a 42% equity component, as in 2006.

VECC submitted that in fact NRG had very little or no equity considering that retractable shares were included as equity. The same view was echoed by the Town in its submission.

The Town in its submission proposed a different calculation to estimate the equity. It used the $3.4 million equity attributable to utility operations in 2006 as the starting point

[8] Technical Conference Transcript, Page 54 (Lines 19-20)

[9] Table 4 in Exhibit E2/Tab 1/Schedule 1, "Opinion on Capital Structure and Equity Risk Premium for Natural Resource Gas"

and used the Board approved ROE of 9.2% for the years 2006 through to 2010 and came up with a 2011 number of $4.65 million. The Town submitted that the $4.65 million number should be used as NRG's actual equity underpinning its utility operations for the 2011 Test Year.

With respect to the Return on Equity, NRG's position was that NRG's risk profile remained unchanged from 2006 and it should therefore receive the same 50 basis points premium.

Board staff in its submission noted that the Board's *Report on Cost of Capital for Ontario's Regulated Utilities* issued on December 11, 2009 was released after the Board's Decision on NRG's 2006 Cost of Service Application. Board staff submitted that the equity risk premium of 550 basis points referred to in the report represents a risk premium that accounts for and considers all utilities across Ontario. In other words, the Board report recognized that the 550 basis points premium did not represent a specific utility but was generally applicable across all utilities. The Town made a similar argument noting that the 550 basis points premium was not based on the individual risk profile of Enbridge Gas and was therefore not appropriate as a base to which a risk premium should apply.

Board staff further noted that in some 2010 cost of service applications intervenors argued that the 550 basis points premium included 50 basis points for floatation and transaction costs. The intervenors submitted that utilities such as Haldimand County Hydro Inc. (EB-2009-0265) and Burlington Hydro Inc. (EB-2009-0259) do not incur any floatation or transaction costs and should therefore not receive the 50 basis points premium. The Board in its Decision agreed with the intervenors but determined that the policy should be applied unadjusted. The reason was that the Board already knew that a number of utilities in Ontario did not issue equity or debt to the public and this was understood throughout the evolution of the Board's approach to setting the ROE.

Board staff used a similar rationale to argue that during the evolution of the report the Board also knew that the utilities shared different risk profiles and were of different sizes but it did not make any distinction on this basis neither made an exception for any of the utilities.

Board staff submitted that there was no compelling evidence to indicate that NRG's risk profile was considerably different from most utilities in Ontario; the Board should therefore award NRG the Board determined ROE of 9.85%.

VECC supported Board staff's argument and noted that in the event the Board decided to depart from policy and award a 50 basis points premium, it would be completely offset by the inclusion of 50 basis points for transactional costs that NRG does not incur.

IGPC in its submission noted that NRG had presented no evidence of the specific risks that distinguish NRG's business from that of other Ontario electricity or gas distributors. With respect to adding the new pipeline, IGPC indicated that NRG was protected by contract terms that obligate contractual payments irrespective of delivery and a letter of credit for the value of the pipeline.

The Town in its submission maintained that the retractable shares that are considered as equity in the Application should in fact be treated as debt until the retraction feature is removed. Accordingly, the Town submitted that the Board should allow a 6.36% return on the value of retractable shares as opposed to 9.85%.

In Reply, NRG stressed that equity injections are atypical to the operation of small private utilities. In 2006, despite the shareholder taking a significant dividend, NRG's actual equity remained at 41.5%. However, with the addition of the IGPC pipeline it had understandably dropped but expected to recover with the retention of earnings. Although NRG's currently actual equity is 37%, NRG argued that over the term of the IR plan NRG's actual capital structure would be 43% equity and 57% debt on a net debt basis. NRG further reminded the Board that the IR plan had not been withdrawn but just moved to Phase 2 and the evidence was still live before the Board.

Addressing the issue of the retractable shares, NRG noted that they have been postponed in favour of the Bank and Union and as long as NRG has some debt, the shares will be postponed in favour of the Bank.

NRG also rejected the Town's method of calculating equity using 2006 utility attributable equity as the starting point and adding a rate of return from 2006 to 2010. NRG argued that the Town had confused retained earnings with over-earning and failed to recognize the concept of just and reasonable rates.

NRG referred to the table[10] in Ms McShane's report and noted that if data for the Ontario electric distribution utilities was omitted, the average equity ratio for the rest of the individual companies was 41.6%.

NRG also referred to the "fair return standard" in the Cost of Capital Report and noted that ultimately the Board determined capital structure and ROE should provide the utility with a fair return. NRG submitted that in an attempt to move to a standardized approach for establishing capital structure and ROE, the Board needed to consider whether the standards provided the utility with a fair return. NRG further argued that mechanically applying the standards would amount to a fettering of the Board's legal discretion.

NRG submitted that the capital structure and ROE established by the Board do not provide a fair return and there was no evidence in the proceeding that supported a different finding from the Board's determination in NRG's previous rates case (EB-2005-0544)

**Board Findings**

There is no consensus on how to determine NRG's capital structure. NRG has itself provided the capital structure on a gross versus net basis. The issue is further complicated by the nature of its shares, which are retractable in nature and classified as a liability according to Canadian Generally Accepted Accounting Principles. The Board is not confident that a definitive number can be established from the Applicant's evidence and record in this proceeding.

The Board has a Cost of Capital policy in place that is applicable to all electric utilities and NRG's size and profile is similar to a number of electric utilities as opposed to the other two large gas utilities (Enbridge and Union). The Board policy on the appropriate equity ratio is 40% and is not considerably different from the ratio sought by NRG.

NRG has submitted that due consideration should be given to the fact that over the term of the five-year IR plan, the actual debt-equity structure would average 53:47 on a gross debt basis. However, the Board in this proceeding is making a determination on 2011 rates. The Board duly notes that an IR plan remains an issue before the Board but the base year rate determination process does not take into account average forecasts for

[10] McShane's Opinion on Capital Structure and Equity Risk Premium for NRG Exh. 2/Tab1/Sch.1, Table 4, page 21

the entire IR period. This is not done for other areas such as capital expenditures or OM&A. The argument that capital structure should, alone among all other elements, be an area where a five year forecast should be considered in determining an appropriate ratio for the Test Year seems inappropriate.

The Board has determined that the appropriate capital structure for NRG is 40% equity, 56% long-term debt and 4% short term debt in accordance with the Board's 2006 Cost of Capital Report[11].

NRG has requested a risk premium of 50 basis points over the Board determined ROE. The Board's current ROE applies to all regulated utilities in Ontario and the Board's 2009 Cost of Capital Report does not make any distinction on the basis of size or risk. The Board during the evolution of setting the ROE already knew that the utilities that it regulates were of different size and risk profiles. This distinction was considered when the 550 basis points premium was determined. NRG has presented no evidence that its risk profile was significantly different from other utilities in Ontario. The Board believes that 9.85% is appropriate and orders NRG to incorporate this ROE in the Draft Rate Order.

NRG alludes to the fair return standard as a legal obligation on the Board. The Board's Cost of Capital Report[12] identifies the elements to ascertain a fair return standard. The Report on page 18 states:

A fair or reasonable return on capital should:

- be comparable to the return available from the application of invested capital to other enterprises of like risk (the comparable investment standard);
- enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and
- permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).

[11] Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, December 20, 2006

[12] Report of the Board on Cost of Capital for Ontario's Regulated Utilities, EB-2009-0084

NRG has provided no evidence that a 9.85% ROE will impact the organization adversely. In fact, at the oral hearing, NRG considered itself to be a stronger utility and provided evidence to its financial viability. NRG referred to the Union Cessation of Service Proceeding and specifically noted that it had never missed a payment to Union. NRG has presented no evidence that its financial viability would be at risk if it receives the Board recommended Cost of Capital. In fact at the oral hearing NRG's witness noted that the asset base had increased substantially and the debt was being reduced aggressively[13].

Although NRG has added the IGPC pipeline, NRG did not face any difficulty in raising the significant amount of capital required to construct the project. There is no evidence to suggest that NRG's lender will change its position if NRG received an ROE that is lower than requested. With respect to equity, NRG has already indicated that the shareholder does not intend injecting any further equity and this was not dependant on the return that is provided. The shareholder has also not provided any evidence that the invested capital can provide a greater return elsewhere with a similar risk profile.

Although NRG has referred to the fair return standard, it has provided no evidence or demonstration how the Board's use of the Cost of Capital parameters will adversely impact NRG or impinge on the fair return standard.

**Cost of Debt**

The debt portfolio of NRG consists of three components: a fixed rate loan, which will be renewed in March 2011, a variable rate loan and a revolving line of credit that is not being utilized. The long-term debt cost of 6.69% reflects a 7.52% interest rate on one of the Bank of Nova Scotia loans, the forecast rate of 4.10% on the other Bank of Nova Scotia loans, plus amortization costs related to the refinancing of previous debt as directed in the NRG 2007 rates case decision (EB-2005-0544). In addition, NRG maintains a compensating balance of $2.75 million in the form of a Guaranteed Investment Certificate ("GIC") with the Bank of Nova Scotia. The amount has been borrowed for the purposes of investing in the GIC.

Board staff submitted that by removing the compensating balance, NRG was using a fairly unusual method to calculate the cost of capital. Although NRG was paying a total rate of 6.69% on its long-term debt, the rate that it was seeking to recover from

[13] Oral Hearing Transcript, Volume 3, page 91 (lines 2-6)

Ontario Energy Board | Commission de l'énergie de l'Ontario

VT INCEPIT FIDELIS SIC PERMANET

Ontario

# EB-2010-0008

## IN THE MATTER OF AN APPLICATION BY

# ONTARIO POWER GENERATION INC.

## PAYMENT AMOUNTS FOR PRESCRIBED FACILITIES FOR 2011 AND 2012

## DECISION WITH REASONS

March 10, 2011

**Table 27: Capitalization and Cost of Capital - Calendar Year Ending December 31, 2012**

| Capitalization | Principal ($million) | Component (%) | Cost Rate (%) | Cost of Capital ($million) |
|---|---|---|---|---|
| | | | | |
| Short-Term Debt | 189.5 | 2.9% | 4.13% | 10.4 |
| Existing/Planned Long-Term Debt | 2,502.8 | 38.8% | 5.50% | 137.6 |
| Other Long-Term Debt Provision | 725.2 | 11.2% | 5.87% | 42.6 |
| Total Debt | 3,417.5 | 53.0% | 5.58% | 190.6 |
| | | | | |
| Common Equity | 3,030.6 | 47.0% | 9.85% | 298.5 |
| | | | | |
| Rate Base Financed by Capital Structure | 6,448.1 | 81.2% | 7.59% | 489.1 |
| | | | | |
| Adjustment for Lesser of UNL or ARC | 1,490.1 | 18.8% | 5.58% | 83.1 |
| | | | | |
| Rate Base | 7,938.2 | 100% | 7.21% | 572.2 |

Source: Exh. C1-1-1, Table 1

The following issues were addressed in the proceeding:

- Technology-specific capital structures;
- Return on equity;
- Cost of short-term debt; and
- Cost of long-term debt.

Each issue is addressed in turn.

## 9.1 Technology-Specific Capital Structures

As noted above, OPG has used a deemed capital structure of 53% debt and 47% equity in its application. The deemed capital structure is applied to the rate base net of the Adjustment for the Lesser of Unfunded Nuclear Liabilities ("UNL") or Asset Retirement

Costs ("ARC"), which is applicable only to the nuclear business. OPG's proposal is consistent with the Board's decision in the previous proceeding.

In the previous proceeding, the Board set one overall capital structure for both regulated hydroelectric and nuclear businesses, but concluded that separate capital structures for the regulated hydroelectric business and the nuclear business was an approach worthy of further investigation at the next proceeding. This is the only issue related to capital structure examined during the proceeding.

In response to the Board's direction in the prior decision, OPG retained Ms. Kathleen McShane of Foster Associates Inc. to determine whether there was a basis on which to establish separate capital structures. Ms. McShane analysed five different quantitative methodologies and one non-quantitative method in her report. Ms McShane also appeared as a witness in the hearing. Ms. McShane concluded that none of the methodologies provided sufficiently robust information to serve as a basis for separate costs of capital and capital structure. Accordingly, OPG concluded that it was appropriate to continue to use a single capital structure for its prescribed facilities.

Pollution Probe filed a report prepared by Drs. Lawrence Kryzanowski and Gordon Roberts. They also appeared as witnesses. Their analysis is based on a heuristic methodology comparing the relative risk of electricity transmission and distribution-only utilities and an integrated (i.e. generation and transmission/distribution) utility versus solely hydroelectric and nuclear generation businesses. They concluded that the capital structure for the hydroelectric business should consist of 43% equity and the capital structure for the nuclear business should consist of 53% equity, subject to OPG's prescribed facilities retaining an equity thickness of 47% in aggregate, as determined in the previous proceeding.

GEC's witness, Mr. Paul Chernick, did not undertake an updated analysis specifically on the issue of technology-specific capital structures, but he did express the opinion that there was a difference in the business risks of hydroelectric and nuclear generation businesses. He testified that the Board could and should make a judgmental determination of the difference.

All consultants agreed that, as the ROE is to remain constant under the Board's Cost of Capital guidelines, the only way to reflect differences in business risk is by adjusting the equity thickness of one division relative to the other.

Pollution Probe maintained that there is no dispute that the nuclear division has a higher business risk than the hydroelectric division. Pollution Probe noted that the capital structure recommended by Drs. Kryzanowski and Roberts was consistent with credit metrics needed to obtain, on a "stand alone" basis, reasonable bond ratings in the "A" credit range. Pollution Probe commented that the methodologies used by Ms. McShane in her analysis are usually used to determine the rate of return, and not the capital structure.

Energy Probe submitted that the Board should deem a higher equity ratio for the nuclear business than the hydroelectric business, setting the nuclear business equity ratio at 50% and the regulated hydroelectric business equity ratio at 40%.

GEC submitted that setting a higher cost of capital for the nuclear business would be more accurate than applying the current combined value to both businesses. GEC submitted that OPG should develop project specific discount rates for large projects to capture business risk more fully in the analysis.

AMPCO, CME, CCC, PWU, SEC and VECC supported retaining a single capital structure for the regulated business. Among the reasons cited were the unnecessary complexity of maintaining two structures and the fact that OPG borrows as a company not by business unit. CCC also commented that the analysis conducted by Drs. Kryzanowski and Roberts was largely a qualitative approach.

Board staff argued that if the Board was inclined to approve technology-specific capital structures, then the Board should also apply the cost of debt on a technology-specific basis. Board staff noted that the nuclear liabilities are treated as a form of debt financing within the capital structure but are only incorporated, appropriately, into the rate base for OPG's regulated nuclear assets.

OPG argued that technology-specific capital structures add unnecessary complications to future applications. OPG noted that consumers do not buy power from particular producers, let alone based on generation type, and that the difference in equity ratios and resulting returns is small. OPG also argued that there is no compelling reason to accept the recommendations of Drs. Kryzanowski and Roberts. In OPG's view, the evidence did not extend the analysis beyond that provided in the previous proceeding and therefore the conclusion of the previous proceeding should be maintained.

If the Board is inclined to approve separate capital structures, OPG submitted that the only reasonable ratios would be 45% for the regulated hydroelectric business and 50% for nuclear. OPG also argued that Board staff is incorrect in concluding that cost of debt is specific to projects, noting that the cost of debt for the projects identified in the staff submission reflect OPG's corporate borrowing costs.

**Board Findings**

OPG has applied the same capital structure as was approved on a combined basis for its regulated hydroelectric and nuclear generation assets in the previous payments case. The Board finds that there is no evidence of any material change in OPG's business risk and that the deemed capital structure of 47% equity and 53% debt, after adjusting for the lesser of Unfunded Nuclear Liabilities or Asset Retirement Costs, remains appropriate.

The Board accepts that the business risks associated with the nuclear business are higher than those of the regulated hydroelectric business, and this is not contested by parties in this hearing. However, the Board finds that the evidence in this proceeding does not provide a sufficiently robust basis to set technology-specific costs of capital, by way of division-specific capital structures. In short, the Board finds an inadequate body of evidence to support a change from the conclusions reached by the Board in the previous proceeding.

The evidence of Drs. Kryzanowski and Roberts is a heuristic approach and is qualitative as much as quantitative in nature. Their evidence also largely employed the same techniques as contained in their evidence in the previous case. The difficulty for the Board is the dependence on qualitative assumptions and analysis. Their qualitative assessments of various forms of risk give rise to quantitative scorings that they then have translated into different capital structures corresponding to a cost of capital related to the risks of each business division and constrained by two conditions:

1) the weighted aggregate cost of capital for the two divisions should correspond with the 47% equity thickness set by the Board on an aggregate basis; and
2) the cost of capital and hence the deemed capital structure for the hydroelectric division should be commensurate with a business risk no less risky than that for electricity distributors and transmitters, for which the Board has deemed a 40% equity thickness.

As was discussed during oral cross-examination, these conditions restrict the allowable technology-specific capital structures to a very narrow band. The Board is concerned that different qualitative scorings might result in some different results from their analysis, even while adhering to the relative riskiness (in terms of ranking) of transmission and distribution utilities versus generation technologies. In other words, as was found in the previous case, the Board considers that the heuristic approach of Drs. Kryzanowski and Roberts is not robust enough to set technology-specific costs of capital and capital structures.

With respect to Ms. McShane's evidence, the Board acknowledges its more quantitative approach, but also acknowledges some of the concerns raised by parties. For the most part, the analytical approaches used by Ms. McShane are based on the CAPM model, and thus share the strengths and limitations. The CAPM is one of several techniques routinely used by this Board and other regulators in setting the Cost of Capital. However, as was acknowledged by OPG,[44] the CAPM is not used to set the capital structure, which must be derived indirectly. However, the Board considers that the paucity of comparator firms to be more telling in Ms. McShane's analysis not being able to derive a robust estimate of technology-specific capital structures.

There may thus be a lack of major hydroelectric and nuclear generators comparable to OPG's divisions and for which market data is available to apply the methods that Ms. McShane has used. It is not to say that there is not a real difference, but that the approaches put on the record in this proceeding, as in the previous case, are not sufficient to allow for robust estimates with sufficient precision to be derived, at least at this time.

The Board is also concerned that over time a further issue will arise in relation to the interaction between the individual equity ratios and the combined equity ratio. As the relative size of the hydroelectric and nuclear businesses changes (through major additions to rate base, for example) the issue will arise as to whether the overall ratio of 47% is to remain unchanged or whether the technology specific ratios are to remain unchanged. If the overall level of 47% is to remain unchanged, then this could result in ongoing variability in the technology specific levels, which may not be desirable. Likewise, if the technology specific ratios are to remain unchanged, it might result in changes to the overall ratio that are not warranted. The Board concludes that introducing this level of variability and complexity would not be appropriate.

[44] Exh. L-10-23 and Exh. L-6-7

The Board also accepts that implementing separate capital structures may not lead to any significant ratepayer benefits in the long term.

The primary argument put forward by those who support a separate capital structure is related to the assessment of large capital projects. The Board concludes that this difference in risk can and should be adequately accommodated in the direct valuation of the projects. OPG maintained that it already does so; other parties dispute this. This issue can be pursued further by the parties in subsequent proceedings.

Another argument advanced in favour of separate capital structures is greater transparency for consumers. The Board has some sympathy with this view, but has nonetheless concluded that the benefits from this greater transparency are not sufficient to warrant the complications involved with this approach based on the evidence advanced in this or the previous payments case.

## 9.2 Return on Equity

Two issues were raised in respect of the return on equity: whether the Board should adjust the ROE below the level established through the operation of the Board's policy, and how the ROE should be set for 2012.

### 9.2.1 Should the ROE be reduced?

OPG proposed that the ROE be determined according to the formula in the Cost of Capital Report, using data from *Consensus Forecasts*, the Bank of Canada and Bloomberg LLP three months in advance of the March 1, 2011 effective date for rates.

CME maintained that unregulated industries would forego full equity return on investment if external circumstances called for price constraint. CME argued that the Board is not required to award ROE at a specific level as this is not an objective or requirement in the Act, and could award a lower rate than applied for by OPG in order to protect consumers from rising electricity prices. CME pointed out that it would be inconsistent for the ROE to be fixed at a specific rate, when the Board, in some cases, can award a higher ROE, as, for example, contemplated by the *Report of the Board on The Regulatory Treatment of Infrastructure Investment in Connection with the Rate Regulated Activities of Distributors and Transmitters in Ontario*. Also, CME suggested

Decision **2011-134**

Alberta Utilities Commission

# ATCO Electric Ltd.

## 2011-2012 Phase I Distribution Tariff
## 2011-2012 Transmission Facility Owner Tariff

**April 13, 2011**

## 7.3 Credit metrics of ATCO Electric transmission and the relevance of CU Inc.'s credit rating

484. Credit metrics are, in general, measures of quantitative data used by rating agencies to assess or compare the financial soundness (risk) of different companies. These metrics are used, together with other factors, by credit rating agencies to establish the credit rating for a company. The higher the credit rating, the lower the risk the rating agency attributes to an investment made in that company. That is, the risk that the company would not pay back its debt to the investor. As such, a company that has a higher credit rating would be viewed as a more secure investment by investors which, in turn, would make it easier for that company to attract investors to finance its debt obligations (bonds or debentures). Additionally, because a company with a high credit rating is considered a less risky investment, investors do not demand as high an interest rate, or rate of return, in exchange for the use of the money represented in that investment.

485. The CCA submitted, in argument, that there is no direct evidence on the record from credit rating agencies regarding a need for improved credit metrics for ATCO Electric's transmission business to avoid a potential downgrade for CU Inc. The only evidence on the record is the most recent reports filed by credit rating agencies (Standard and Poor's (S&P) and Dominion Bond Rating Service (DBRS)) and the view expressed by ATCO Electric's finance and cost of capital witness, Ms. McShane, as to how these rating agencies might react to ATCO Electric credit metrics as a result of its forecast capital program. The CCA further stated that in the absence of any definitive statements from either S&P or DBRS indicating that declining credit metrics in ATCO Electric will negatively impact CU Inc.'s credit ratings and/or result in a downgrade, little weight should be placed on ATCO Electric's evidence about the need to improve credit metrics relied upon by credit rating agencies.[307] Further, the CCA commented that potential impacts on the credit metrics were temporary, with the build cycle forecast to probably continue to approximately 2015.[308]

486. In argument, the CCA submitted that in making their determinations, credit rating agencies: are informed and recognize that CU Inc. will experience, in large part as a result of the impending transmission build, significant cash flow deficits; are willing to exhibit some leniency during a high build period given that impacts on credit metrics are temporary; use both quantitative and qualitative measures to determine credit ratings on individual companies; and place significant weight on the stable regulatory environment in Alberta. The CCA further submitted that due to all of these factors the credit ratings agencies have expressed no major concerns in relation to the current and impending significant growth in transmission and the need for increased levels of debt to finance this growth. Both [DBRS] and S&P's most recent credit reports maintain CU Inc.'s existing credit ratings in spite of full knowledge as to the nature and extent of the current and impending transmission build and the significant free cash flow deficits.[309]

487. The UCA further submitted that during the oral hearing it presented Ms. McShane with actual credit metric scores for Alberta utilities, and compared them to the standards from S&P.

[307] Exhibit 180.01, CCA argument Module 2, paragraphs 16-19.
[308] Exhibit 180.01, CCA argument Module 2, paragraph 30.
[309] Exhibit 180.01, CCA Argument Module 2, paragraphs 21-44.

Ms. McShane confirmed that the ratios are below those required for an A rating, yet despite this, the actual rating for most Alberta utilities is an A rating or better.[310]

488. ATCO Electric noted in its argument that no party on the record, including ATCO Electric, is alleging that the relief measures requested for ATCO Electric are required in order to maintain CU Inc.'s existing credit rating or that a failure to grant the relief measures requested will result in CU Inc. experiencing a bond downgrade. Rather, the relief measures requested are required in order to ensure that, on a stand-alone basis, ATCO Electric has sufficient credit metrics to contribute its fair share to the maintenance of CU Inc.'s existing ratings. ATCO Electric further noted that there will be continued pressure on CU Inc. if ATCO Electric fails to contribute its fair share to the maintenance of CU Inc.'s credit rating.[311]

489. In reply, ATCO Electric stated that it is not suggesting that there is an imminent threat of a downgrade to CU Inc.'s credit rating regardless of whether the requested relief measures are granted or not. Rather the point is that, if the relief measures are not approved, ATCO Electric, on a stand-alone basis, would not be contributing its fair share to the maintenance of CU Inc.'s credit rating, because of the credit metrics that would exist during this massive capital build period.[312]

**Commission findings**

490. ATCO Electric transmission does not go to the financial market to raise money, or capital, in its own name. Rather, CU Inc., as the owner of ATCO Electric transmission, raises funds and when needed by ATCO Electric transmission, lends funds to ATCO Electric transmission. The cost of the money (interest rate) that CU Inc. borrows in the market is passed down at cost to ATCO Electric transmission. This is known as mirroring down the cost of debt.

491. Investors who lend money to CU Inc. do so based on the credit rating of CU Inc. The credit rating of CU Inc. is influenced by the financial performance of the utilities it owns, including ATCO Electric transmission. As CU Inc. is the owner of more than one company, it could be viewed by the market as less risky than would be the market's view of ATCO Electric, standing alone, and raising funds on its own in the market.

492. The Commission finds that it is necessary and reasonable that ATCO Electric transmission contribute to the maintenance of CU Inc.'s credit rating. If it did not do so, ATCO Electric transmission could potentially make an argument that it should no longer mirror down the debt cost of CU Inc.

## 7.4 CWIP in rate base and recovery of transmission federal FIT

493. In its application, ATCO Electric described that given the transmission capital program forecast (as discussed above in detail in Section 4.2.1 of this decision) and the significant amount of construction work in progress, ATCO Electric transmission and ultimately, CU Inc. will be experiencing pressure on its credit metrics and debt ratings. ATCO Electric submitted the capital build program forecast creates a situation where a significant portion of ATCO Electric's earnings will be non-cash earnings as opposed to real cash earnings, as a high level of capital

[310] Exhibit 178.01, UCA argument Module 2, paragraph 38.
[311] Exhibit 179.01, AE argument Module 2, paragraph 15.
[312] Exhibit 183.01, AE reply argument Module 2, paragraph 18.

expenditures will be accrued to construction work in progress.[313] ATCO Electric sought the following temporary relief measures to continue to contribute its fair share to support the maintenance of CU Inc.'s credit rating:

- approval to include transmission direct assigned construction work in progress in rate base (CWIP in rate base)
- approval to recover transmission federal future income taxes (FIT)

494. The impact of ATCO Electric's request on its transmission revenue requirement is summarized in the table below.

**Table 52. Revenue requirement increase and impact of including CWIP in rate base and recovering FIT**

| | 2011 | 2012 |
|---|---|---|
| CWIP[314] | $41.2 | $49.3 |
| Additional CWIP from omissions and updates filing[315] | 4.6 | 19.5 |
| FIT[316] | 11 | 16.4 |
| **Total** | **$56.8** | **$85.2** |
| **Percentage of forecast transmission revenue requirement[317]** | **17%** | **19%** |

495. In the application, ATCO Electric submitted that its proposal for the temporary use of the future income tax method for transmission federal income taxes was consistent with the temporary treatment approved in the AltaLink 2009-2010 GTA in Decision 2009-151 related to its forecast significant capital programs. ATCO Electric further proposed to re-evaluate the need to recover future income taxes in future applications when its capital program returned to typical levels.[318]

496. ATCO Electric observed that if the Commission denied its request for CWIP in rate base and FIT, ATCO Electric transmission would not pay income taxes in 2011 and 2012 and would expect to be non-taxable for the near term future and would be entitled to a 2 per cent increase in its deemed common equity ratio consistent with past Commission decisions for non-tax paying entities.

497. ATCO Electric stated in argument that in its current circumstances it requires both CWIP in rate base and recovery of (transmission federal) FIT to address the unique circumstances created by the extensive capital build program planned by ATCO Electric transmission for the test period. ATCO Electric stated that during the 2011-2012 test period construction work in progress will represent over 25 per cent of the total transmission assets.[319]

313 Exhibit 179.01, AE argument Module 2, paragraphs 9 and 10.
314 Exhibit 2.00, AE application, Section 3, Attachment 2, Analysis of Rate Increase, line 7.
315 Exhibit 89.02, AE omissions and updates filing, Schedule 7, line 24.
316 Exhibit 2.00, AE application, Section 3, Attachment 2, Analysis of Rate Increase, line 13.
317 For 2011 $56.8/336.6 and for 2012 $85.2/448.6.
318 Exhibit 2.00, AE Application, paragraph 618.
319 Exhibit 179.01, AE argument Module 2, paragraphs 7 and 8.

498. The UCA engaged Drs. Kryzanowski and Roberts as expert witnesses to review ATCO Electric's application. ATCO Electric submitted that this was also acknowledged and agreed to by the UCA's expert witnesses during the hearing when questioned by ATCO Electric:

> Q And do you have any understanding of how that magnitude of capital program relates to ATCO Electric's historic capital programs, as in, do you think it's much larger?
>
> DR. ROBERTS: Yes. It's definitely much larger.
>
> Q Orders of magnitude are higher? Would that be fair?
>
> DR. ROBERTS: Orders of magnitude higher -- I think, if I remember correctly, we had, on the earlier figure, that it was an increase on the order of around 25 percent of their capital, but I'd have to check that. That would be an order of magnitude, yeah.[320]

499. For added context ATCO Electric indicated that the typical proportion of construction work in progress for utilities in Alberta (excluding ATCO Electric transmission and AltaLink) has been approximately four per cent in comparison to its 25 per cent and therefore reiterated that ATCO Electric transmission is clearly dealing with a very unique and unusual set of circumstances at this time.[321]

500. The CCA submitted that it was concerned that temporary measures not become permanent practices. With respect to construction work in progress, the AUC and its predecessors have historically approved CWIP/AFUDC[322] as a means of ensuring that current customers do not pay for costs and assets that will be realized and used in the future. Similarly, the tax method has been treated on a cash (or flow-through) basis to recognize that current customers should not have to pay for future liabilities.[323]

501. The CCA further submitted that while prepayment of costs associated with CWIP in rate base and the FIT method may assist the utility in terms of increased cash flows, it is clearly not in the best interests of customers. Historically, the rating agencies have accepted the CWIP/AFUDC treatment and the cash method of accounting for income taxes, as approved by the regulator in Alberta. In fact, the DBRS and S&P bond rating reports included in ATCO Electric's application do not once express any concern with respect to the currently-approved CWIP/AFUDC treatment or the cash method of income tax treatment.[324]

502. In argument ATCO Electric addressed the CCA's issue that it is neither ATCO Electric nor interveners who decide if and when any temporary relief measures are modified or discontinued. ATCO Electric submitted that this decision lies with the Commission and the Commission will be aware of not only ATCO Electric's annual capital program, but also the resulting impact on credit metrics. Furthermore, ATCO Electric noted that interveners would

[320] Transcript, Volume 8, page 1548, line 25.
[321] Exhibit 179.01, AE argument Module 2, paragraph 8.
[322] The historical practice has been to provide a return on the utility's investment in construction work in progress by adding an allowance for funds used during construction to the rate base amount for these assets. This was a capitalized return that provided a non-cash return that would be collected in cash through higher depreciation charges over the life of the asset.
[323] Exhibit 180.1, CCA argument Module 2, paragraph 45.
[324] Exhibit 180.1, CCA argument Module 2, paragraph 46.

quickly remind the Commission that the circumstances which led to the granting of temporary relief had indeed changed, hence such relief should be modified.[325]

503. The CCA submitted in its summary that it does not support either the proposal to include transmission CWIP in rate base or to change the income tax accounting treatment for transmission federal taxes from the flow-through method to the FIT method. However, if the Commission determines that some relief is necessary, the CCA would support the temporary adoption of the FIT method for the test period, as proposed by ATCO Electric, until about 2015.[326] The CCA submitted that 2015 is an appropriate time frame to allow all parties to examine if ATCO Electric requires this relief measure going forward. The CCA also submitted that under the FIT method there is some benefit to customers because under FIT the prepayments from customers are collected in a no-cost capital deferral account which is subtracted from rate base, reducing the utility's return payable by customers.

504. In their evidence Drs. Kryzanowski and Roberts summarized the UCA's recommendation on the relief measures proposed by ATCO Electric:

> …we recommend that the Commission attach no weight to ATCO's claim for relief. In our view, the Commission should revisit the equity thickness of AE Transmission and Distribution in the 2011 Generic Hearing given the changed financial environment. The Commission should reject the inclusion of either CWIP-in-RB or FIT. If however, the Commission wishes to grant further relief to ATCO Electric Transmission because of its capital build program, it would be overly generous to do so while maintaining the current equity thickness. In this case, we recommend that the Commission should adopt our second scenario in which 25% of CWIP is included in rate base, FIT is excluded and the equity thickness is reduced by 1%.[327]

505. IPCAA submitted in argument that ATCO Electric's request to allow CWIP in rate base would result in existing rate payers being asked to pay for assets that have yet to enter into service and would not be used and useful in the traditional sense. IPCAA stated that ATCO Electric's proposal raises significant ratepayer concerns because it amounts to a request for customers to pay now before ATCO Electric provides the utility assets or service associated with them. IPCAA also submitted that construction work in progress assets will still be subject to a prudence review, that there are many issues that ratepayers can and will likely raise with respect to the level of costs claimed in relation to assets that are being brought forward for inclusion into rate base, and that ratepayers should retain the right to scrutinize costs when they are brought forward for inclusion into rate base.[328]

506. In response to IPCAA's concern, ATCO Electric submitted that all direct assigned projects, including CWIP in rate base, are covered by a deferral account, which reconciles actual to forecasts on an annual basis. Therefore, the prudence of all costs will be tested for these projects. ATCO Electric also confirmed in its argument that amounts associated with CWIP in rate base would also be covered by the deferral account.[329]

[325] Exhibit 179.01, AE argument Module 2, paragraph 10.
[326] Exhibit 180.1, CCA argument Module 2, paragraphs 50, 65, and 69.
[327] Exhibit 81.02, Redacted UCA evidence on CWIP and FIT, paragraph 221.
[328] Exhibit 177.02, IPCAA argument Module 2, pages 4 and 5.
[329] Exhibit 183.01, AE reply argument Module 2, paragraph 31 and Exhibit 179.01, AE argument Module 2, paragraph 41.

507. ATCO Electric submitted that on a net present value basis ratepayers should ultimately be indifferent to the accumulation of AFUDC versus the inclusion of CWIP in rate base, as well as, to the adoption of the FIT methodology. This is because on a net present value basis the financial impact on ratepayers is the same using either approach. These items relate to the timing of the receipt of cash, but do not impact the overall costs to customers. As such, when the magnitude of the test year impacts are viewed in the proper context it is readily understood that receiving more revenue now means receiving less later. ATCO Electric submitted that the Commission should not be misled by the one-sided picture interveners are trying to create. In fact, as stated in argument, there is the potential for higher debt costs resulting from degrading credit metrics and the corresponding result of CU Inc.'s spreads moving negatively within the A range of companies.[330]

508. The UCA submitted that customers prefer to pay later.[331]

509. ATCO Electric's evidence requesting the adoption of relief measures was supported by the expert testimony of Ms. Kathleen McShane filed as Exhibit 144.03 to the application. Ms. McShane submitted in her evidence that the minimums identified by the Commission itself (in Decision 2009-216) to constitute a low A credit rating are as follows:

**Table 53. Minimum credit metrics associated with a low A credit rating as observed by the Commission in Decision 2006-216[332]**

| | |
|---|---|
| Earnings before interest and taxes (EBIT) | 2.0 times |
| Cash from operations interest coverage (FFO) | 3.0 times |
| FFO/debt | 11.1% to 14.3% |

510. Ms. McShane further submitted that when these minimum credit metrics are compared to the updated credit metrics provided by ATCO Electric in its rebuttal evidence, which reflect the capital program updates contained in ATCO Electric's omissions and updates filing, it is clear that for the 2011 and 2012 test years, without any additional relief measures, ATCO Electric's transmission credit metrics fall materially below the minimums identified by the Commission. This is shown in the table below:

**Table 54. Updated credit metrics for ATCO Electric in 2011 and 2012 without any additional relief measures[333]**

| | 2011 | 2012 |
|---|---|---|
| Earnings before interest and taxes (EBIT) | 1.6 | 1.54 |
| Cash from operations interest coverage (FFO) | 2.66 | 2.47 |
| FFO/debt | 9.90% | 8.90% |

511. As a result, ATCO Electric submitted that unless action is taken by the Commission to provide additional relief through the adoption of the further measures discussed in the context of Decision 2009-216, ATCO Electric transmission will not maintain adequate credit metrics; hence it will not contribute its fair share to the maintenance of CU Inc.'s credit rating.

330 Exhibit 183.01, AE reply argument, Module 2, paragraph 9.
331 Exhibit 178.01, UCA argument Module 2, paragraph 6.8
332 Decision 2009-216, Table 12 and paragraphs 348, 354 and 356.
333 Exhibit 144.01, AE rebuttal evidence, McShane Schedule 1, page 1, current treatment.

512. The CCA submitted that, should CWIP in rate base be allowed, when the assets in construction work in progress are transferred to rate base they will significantly enhance the credit metrics, not only for ATCO Electric transmission but also for CU Inc. The CCA argued that ATCO Electric transmission may, in fact, end up cross-subsidizing other CU Inc. subsidiaries, if such subsidiaries are not able to pull their weight where credit ratings are concerned.[334]

513. Drs. Kryzanowski and Roberts, stated in argument that the credit metric definitions used by Ms. McShane differ from published norms and that the ratios used by her are different than those used by the Commission as part of decision 2009-216. The UCA stated in its argument:

> In cross, she conceded that the ratios used by her differ from those used by the Commission in their 2009 Generic decision in that the Commission had omitted consideration of CWIP and did not consider the impact of some utilities actually collecting more taxes than they actually paid.[335]

514. ATCO Electric submitted that in Decision 2009-216, the Commission's calculations did not consider the impact of the presence of construction work in progress and the impact of an effective income tax rate lower than the statutory rate. However, ATCO Electric states that given the circumstances of ATCO Electric transmission, these items cannot be ignored. ATCO Electric describes that calculating credit metrics, including the impact of construction work in progress and the effective income tax rate, is to demonstrate how much weaker the actual credit metrics would be in these circumstances at the current equity ratios.[336]

515. The UCA took a similar position and also echoed the fact that bond rating agencies do not merely apply or follow a simple formula, Drs. Kryzanowski and Roberts explained:

> Although bond rating agencies certainly pay attention to ratios, there is no formula which translates ratios into bond ratings as considerable judgment comes into play. Simply having a key ratio below a certain level is not by itself grounds for a downgrade in practice.[337]

516. The UCA stated that during cross Ms. McShane did ultimately concede that ratings agencies are not completely formulistic:

> Q. I just wanted to get your opinion on whether credit rating agencies give more weight to quantitative factors as opposed to qualitative, if it's an equal weighting?
>
> A. MS. McSHANE: I think it depends on the credit rating agency. They certainly give significant weight to quantitative factors. I know, for example, that Moody's, which is perhaps a little bit more formalistic, I guess, if you will, with their credit rating methodology in S&P -- I mean, they tell you specifically how much weight they give to sort of the qualitative business risk or, you know, regulatory framework aspect of the rating and how much weight they give to the quantitative measures.

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334 Exhibit 180.1, CCA argument Module 2, paragraph 37.
335 Exhibit 178.01, UCA argument Module 2, paragraph 28.
336 Exhibit 183.01, AE reply argument Module 2, paragraph 26.
337 Exhibit 81.02, Redacted UCA Evidence on CWIP and FIT, paragraph 91.

> And they're basically 60 percent qualitative, 40 percent quantitative. S&P is not as transparent about that. Although, they do say the most significant thing they look at is cash flow ratios.[338]

517. The CCA summarized by stating that if for credit rating purposes, ratings agencies are willing to "look through the cycle" of high capital builds in ATCO Electric transmission and the corresponding impacts on credit metrics, it is not clear why the Commission should do otherwise for rate making purposes.[339]

518. ATCO Electric further submitted that none of the interveners have refuted the fact that ATCO Electric's transmission stand-alone credit metrics will be below the minimums established by the Commission in Decision 2009-216 required for a low A credit rating. ATCO Electric's transmission credit metrics fall materially below those minimums identified by the Commission for both the 2011 and 2012 test years. As such, absent the adoption of the further measures discussed in the context of Decision 2009-216, ATCO Electric will not contribute its fair share to the maintenance of CU Inc.'s current credit ratings.[340]

**Commission findings**

519. The Commission, in its findings below has employed its specialized expertise as a tribunal familiar with and legislatively mandated to examine the costs and expenses associated with capital related to the owner's investment in the electric utility.[341] As noted by the federal court of appeal in *Masjef v. Canada (Minister of Manpower & Immigration)* [1977] 1F.C. 194 at 198:

> … no tribunal can approach a problem with its collective mind blank and devoid of any of the knowledge of a general nature which had been acquired in common with other members of the general public, through the respective life-times of its members, including perhaps most importantly that acquired from time to time in carrying out their statutory duties.

520. The Commission first discussed the possible implementation of the relief measures requested in this application in Proceeding ID No. 102, which resulted in the release of Decision 2009-151. The Commission's exploration of this issue included submissions from AltaLink Management Ltd., ATCO Electric and Consumers Group.[342]

521. The Commission will address the requested relief measure under the following four sub-headings:

- The impact of CWIP in rate base and FIT on the utility and its customers
- Is the relief needed to support credit metrics?

[338] Transcript, Volume 7, page 1410.
[339] Exhibit 181.01, CCA reply argument Module 2, paragraph 8.
[340] Exhibit 183.01, AE reply argument Module 2, paragraph 19.
[341] See section 122 of the *Electric Utilities Act*. Administrative tribunals may have some higher degree of latitude in utilizing specialized expertise available to a tribunal. However, the circumstances in which official notice is employed by a tribunal must be fair. D. P Jones and A.S. deVillars, *Principles of Administrative Law*($5^{th}$) (Scarborough, Ontario: Thomson Carswell, 2004) pages 307-309.
[342] Decision 2009-151, Section 10.2.

- Intergenerational equity
- Conclusion

*The impact of CWIP in rate base and FIT on the utility and its customers*

522. At the outset it is useful to review, at a high level, the manner in which the Alberta regulated utilities make money. A utility invests the money of its shareholders (equity) as well as borrowed money (debt) to pay for their assets. The Commission approves rates that are expected to provide the utility with a reasonable opportunity to collect enough money from its customers to earn a fair return on its invested equity, and pay interest on its debt.

523. A portion of a utility's assets is financed by customers rather than the utility. This customer financing includes the following:

- money that the utility has pre-collected to create reserve accounts for future hearing costs and for self insurance against injuries and damages
- money that the utility has pre-collected to cover the payment of certain income taxes it anticipates paying at some point in the future
- money collected from specific customers as customer contributions towards the costs of building infrastructure assets to serve those specific customers

524. Electric utilities earn a return on the money that is invested in the infrastructure (assets) that they own and operate and use to provide electric service to their customers. In this manner, utilities are rewarded for building, owning and operating infrastructure. In the absence of competition, the regulator holds this incentive in check by limiting the return to a competitive level and by not permitting the utility to earn a return on the money it invested in infrastructure if the cost of the investment is not reasonable or if the investment was not approved by the regulator as required to provide service to the utility's customers.

525. Each additional dollar approved by the regulator for investment in the utility's infrastructure, and which has not been financed by customers, adds to the return earned by a utility.

526. Utilities add infrastructure in cycles. The cycle of building, maintaining, and replacing infrastructure is normal for the electrical industry; however, for transmission assets, that cycle can last for decades. As well, due to the technology used in new transmission assets and the impacts of general inflation, constructing (adding) new infrastructure is usually more expensive than what it cost to construct infrastructure in the past.

527. The relief requested by ATCO Electric, and which has been commonly referred to as CWIP in rate base, is a mischaracterization. The relief requested is really a request to suspend current construction work in progress accounting procedures to reduce the potential for a downgrade of ATCO Electric's credit rating. It is a financing mechanism to smooth the cash flows that occur because of this cycle.

528. Under current accounting procedures, during the period under which a utility is building new infrastructure, it does not earn a cash return on the value of that asset until that asset is able to be used to provide electric service to the utility's customers. A non-cash return, known as an

[221] En termes de risque d'affaires, le développement de l'entreprise dans les marchés résidentiels et d'affaires s'est poursuivi au cours des derniers dix ans tel qu'il pouvait l'être anticipé. La base de revenus stables de l'entreprise s'est donc renforcée.

[222] La perte récente de grands clients industriels constitue, toutes choses étant égales par ailleurs, un point négatif. Toutefois, la preuve révèle que cette perte est attribuable principalement aux difficultés d'ordre structurel dans un secteur précis d'activité économique et qu'elle ne résulte pas, par exemple, d'une dégradation de la compétitivité du gaz naturel. Enfin, la perte de marge brute y reliée n'affecte pas de façon indue le niveau des tarifs qui en résultent pour les autres usagers.

[223] Par ailleurs, le fait que Gazifère est une entreprise dont la taille ne lui permettrait pas d'accéder en propre aux marchés financiers et que sa notation, le cas échéant, serait vraisemblablement établie à BBB doit être pris en considération.

[224] Pour ces motifs, l'ajustement proposé de 50 points de base apparaît justifié.

[225] Enfin, l'argument du D$^{r}$ Booth concernant le fait que les coûts qui découlent de la petite taille de Gazifère ne devraient pas être facturés aux consommateurs, bien que soulevant un enjeu d'intérêt sur le plan des principes réglementaires, ne peut être retenu dans la mesure où le cadre réglementaire existant de Gazifère repose sur le concept de l'isolement. Une application substantiellement différente de ce concept constitue un enjeu de portée très large dépassant le cadre de la présente audience.

**Taux de rendement de Gazifère pour 2011**

[226] Sur la base de ce qui précède et d'un taux sans risque de 4,25 %, le rendement de Gazifère peut être situé à l'intérieur d'une plage variant entre 8,60 % et 10,01 %.

allowance for funds used during construction (AFUDC), is provided to the utility by adding the return to the rate base of the asset under construction.[343] That is, utilities are permitted to capitalize the interest cost and foregone earnings during the years the asset remained under construction. These capitalized costs are added to the concrete costs of the asset and are included as part of the value of the asset for the purpose of establishing the value of the rate base of the utility.

529. During a construction cycle, the utility must pay the construction costs for this asset which, in turn, impacts the cash flow of the utility. Cash flow is one of the credit metrics that is considered by rating agencies when establishing a credit rating for a company.

530. In the event that the 2011-2012 direct assigned capital program projects proposed in Section 4.2.2 of the application are approved, ATCO Electric would experience abnormally high levels in its construction work in progress accounts. As stated above, the typical proportion of construction work in progress for utilities in Alberta (excluding ATCO Electric and AltaLink) has been approximately four per cent of the utility's total assets (rate base). The current forecast represents 25 per cent of ATCO Electric's transmission assets during the build cycle. In this instance, it is not unreasonable for ATCO Electric to request some sort of relief to help deal with the cash flow implications resulting from these abnormally high balances in its construction work in progress account.

531. If the current construction work in progress accounting measures are suspended, the utility will be entitled to recover the cost of the money it requires for construction (interest) as that money is spent. The utility will not be entitled to recover, through rates charged to the customer, the principal costs of the project until the project is approved and the project is put into service.

532. The Commission also notes that by suspending the current construction work in progress accounting procedures, in the long run, the overall cost to customers for new assets is less than what it would be under the current CWIP/AFUDC accounting practice. This is because it is always more expensive to postpone payment of an asset due to the interest or return cost associated with postponing payments. As a simple analogy, suspending this relief is similar to financing a home by putting a larger down payment on a home at the outset. The home is less costly in the long run because the down payment has reduced the amount of interest paid over the life of the mortgage. Therefore, in the long run, the suspension of current construction work in progress accounting measures reduces the total cost of an asset because it reduces the amount of return customers pay to the utility.

533. The Commission further notes that customers' interests will nonetheless be protected in the event that the 2011-2012 direct assigned capital program projects proposed in Section 4.2.2 are not approved and/or the cost of a direct assigned project changes. This is because balances in construction work in progress only start to accrue when the utility starts using funds for a direct assigned project. Therefore if a project is not approved by the Commission, the utility will not be able to accrue the expenditures related to it. In addition, because all direct assigned projects are covered by a deferral account, any balances in construction work in progress accounts will also be covered by the same deferral account treatment. Under deferral account treatment, customers

[343] Exhibit 2, AE application, paragraph 632 and Exhibit 179.01, AE argument Module 2, paragraph 9.

will only pay a return on those actual and approved balances in the construction work in progress account.

534. With respect to the request for future income taxes (FIT), some explanation is necessary. Using the FIT method, income taxes are collected based on accounting income and applying the applicable tax rates. These accounting income taxes typically exceed the amount actually payable to the tax authorities. In contrast, ATCO Electric's current flow-through method of taxes requires that the utility determine the least amount of cash income taxes that is forecast to be payable to the tax authorities and only collect that amount from customers. Therefore, the use of the FIT method would allow ATCO Electric to pre-collect certain amounts for income tax before it actually needed to be paid.[344] The pre-collected income taxes would be recognized as no-cost capital, thereby reducing ATCO Electric's required investment in rate base, hence its return on capital invested in rate base.

535. The Commission notes that it is only certain utilities that are allowed, under accounting rules, to reflect only the cash taxes payable in their accounting income statements. The FIT method is mandated for all companies in Canada other than certain regulated companies.

536. When asked in the hearing if ATCO Electric would consider staying on FIT after the impact of its capital program had subsided, or expanding the use of FIT to transmission provincial income taxes or distribution income taxes, ATCO Electric responded that this was something that it would consider. ATCO Electric submitted:

> Q And why not stay on future income taxes once these builds are over?
>
> A MR. EDMONDSON: Future income taxes --
>
> A MR. SHKROBOT: Well, maybe I could respond to that. I guess, you know, we haven't made an application to this date yet to – for distribution and for the provincial part for transmission. But , you know, that's -- I guess an application may be coming in the future for not just our utilities, but -- for us, but other utilities, given the removal of the exemption and maybe perhaps impact of IFRS, what it's going to look like in a year from now. So I guess that's what in terms of a temporary basis, we would have to look at the circumstances, and if the circumstance warrants us to continue in the full future income tax for both distribution and transmission, we might look at that.[345]

537. Both CWIP in rate base and FIT are accelerated cost recovery mechanisms which alter the time between cash inflows and outflows to a utility.[346]

### *Is the relief needed to support credit metrics?*

538. Both suspending current construction work in progress accounting treatment and FIT would reduce ATCO Electric's requirement and opportunity to invest in rate base. This is because FIT must be recognized as financing by customers and accounted for as no-cost capital. Absent suspending current construction work in progress accounting treatment, the return on construction work in progress is recognized in a non-cash manner by adding that return to the rate base value of the asset under construction.

[344] Exhibit 162.01, Income Tax Inquiry, Report No. E79079, August 1, 1979, Section 3.
[345] Transcript, Volume 7, pages 1466-1467.
[346] Exhibit 81.02, redacted UCA evidence, paragraphs 20-25.

539. ATCO Electric explained that it required these measures in order to insure that ATCO Electric's transmission credit metrics were sufficient.[347] Interveners argued that these measures were not in fact required to support the credit metrics.[348] However, interveners did not explain why ATCO Electric would propose measures that reduced its opportunity to invest in rate base if it were not necessary to support the credit metrics.

540. Accelerated cash flows do enhance credit metrics. But they reduce the opportunity to keep equity capital invested in rate base and earning a return. When a utility proposes a measure that reduces its opportunity to invest in rate base which, when viewed in isolation is a detriment to the utility, the Commission will assign more weight to the utility's proposal.

541. ATCO Electric demonstrated in tables 53 and 54 above that its credit metrics would fall well below the minimum levels that the Commission had observed, in Decision 2009-216, appeared to be sufficient to obtain, or were associated with, a credit rating in the lower A range, based on the available sample of five relatively pure play Canadian regulated utilities.[349] Interveners did not dispute that the stand alone credit metrics for ATCO Electric transmission would fall well below the minimums that the Commission had observed in Decision 2009-216.

542. Interveners argued that the low credit metrics associated with the unusually large capital expenditures were temporary in nature and that the credit rating agencies would look past this and would not mechanistically apply minimum credit metric requirements. While there may be some support for this view, ATCO Electric has nevertheless requested these measures despite the negative implications on its opportunity to invest in rate base. The record shows there is no dispute that for ATCO Electric transmission the credit metrics would be below the minimums observed by the Commission in Decision 2009-216 and it is for this reason that ATCO Electric has sought relief.

### *Intergenerational equity*

543. ATCO Electric has argued that customers should be indifferent to suspending current construction work in progress accounting treatment and to the collection of FIT, resulting in a lower utility investment in rate base rather than paying for a return on a higher investment in rate base over future years. The UCA argued that customers prefer to pay later.

544. The Commission notes that the amount of depreciation and return that customers are currently paying on old infrastructure is lower due to the average age of the transmission assets. It is the nature of the electric system that investment in new facilities is more expensive than the investment once made on the old facilities. The Commission takes into account the intergenerational equity issues that present themselves in this case but weighs them against the realities that occur from a significant build cycle: i) the vast majority of the customers of today will still be customers in several years when the assets enter service; ii) if the Commission determines that credit relief is required today then it must be provided today; iii) it is not clear if customers of today would benefit by deferring paying for this cost today when the result would be higher costs in the future and could potentially be higher debt costs today as well, if it were determined that ATCO Electric transmission has a lower stand alone credit rating; and iv) the amount of depreciation and return that customers of today are currently paying on old

[347] Exhibit 179.01, AE argument Module 2, paragraphs 9 and 16.
[348] Exhibit 180.01, CCA argument Module 2, Section 3 and Exhibit 178.01, UCA argument Module 2, Section D.
[349] Decision 2009-216, Table 12 and paragraphs 348, 354 and 356.

infrastructure is lower due to the average age of the transmission assets compared to customers of yesterday but that mismatch from the past and into the future is the nature of large capacity additions.

### *Conclusion*

545. It is not disputed that ATCO Electric transmission faces the requirement to finance abnormally large levels of construction work in progress or that this will reduce its stand alone credit metrics to well below the minimum levels that the Commission had observed in Decision 2009-216 were associated with low A credit ratings.

546. As discussed above, suspending current construction work in progress accounting treatment reduces the total cost of an asset because it reduces the amount of return customers pay to the utility and, under deferral account treatment, customers will only pay a return on actual project costs incurred and only on approved project balances in the construction work in progress account.

547. As noted above, the Commission does not have a large concern regarding inter-generational equity in this case. The Commission does not believe that customers will be harmed by beginning to pay for this cost now rather than paying it as a higher amount in the future.

548. The Commission finds that granting the relief requested by ATCO Electric is prudent and in the public interest. This finding may be revised in future as circumstances change.

549. The Commission, pursuant to Section 122 of the *Electric Utilities Act,* when approving a tariff, must have regard to the impact that its decision will have on the financial health of the utility it regulates. As well, the Commission must also ensure that it minimizes the effects on consumer rates. In circumstances where capital expenditures are forecast to be much higher than in the past, the traditional rate regulatory accounting approach may not allow the Commission to effectively carry out those tasks. Therefore, the Commission must respond. In this proceeding, the Commission has chosen to respond by allowing the utility to recover the financing costs of the assets (but not the costs of the assets) through rates today so that the utility can maintain its financial health and keep its interest costs and other financing costs down during the construction period. Further, customers are not burdened by higher interest and other financing costs today and customers ultimately pay less overall for the new assets that may be approved and constructed.

550. The findings in this decision and in particular in this section, do not provide and cannot be construed as any pre-approval of the need or facility permits and licences to operate for any of ATCO Electric's forecast transmission projects; nor do these findings provide any advanced approval of the prudence of any investments that may be required.

551. Finally, the Commission clarifies that its findings in this decision to permit ATCO Electric to suspend current construction work in progress accounting treatment and to adopt the FIT method for transmission federal income taxes have been made with respect to the specific evidence presented in this proceeding applicable to ATCO Electric transmission. These findings are not a generic finding to be applied to other transmission facility owners. Rather, the Commission will assess the need to provide this relief, or other relief, to other transmission facility owners on the basis of each of their individual circumstances, on application by the transmission facility owner.

## 7.5 Equity ratio (capital structure) issues

552. ATCO Electric submitted evidence during the proceeding that supported its view that circumstances which would impact ATCO Electric's awarded capital structure have not changed materially since the time Decision 2009-216 was issued. ATCO Electric submitted that in Decision 2009-216, the Commission employed its common practice of making use of the best information available at the time the record closed and therefore the most appropriate comparison for purposes of examining whether any material change in circumstances have occurred between the close of the 2009 Generic Cost of Capital proceeding and this application should be based on the record that was actually considered by the Commission in its decision making process.[350]

553. ATCO Electric submitted in argument that Drs. Kryzanowski and Roberts seek to compare the circumstances that existed during the depth of the economic crisis (late 2008/early 2009) and compare those circumstances to the prevailing economic conditions. ATCO Electric further stated that by doing so Drs. Kryzanowski and Roberts ignore the fact that by the time the actual public hearing for the 2009 Generic Cost of Capital proceeding was held, economic circumstances had improved dramatically from the low point experienced earlier. ATCO Electric submitted that Ms. McShane's evidence shows that while market conditions have improved dramatically from the depths of the economic crisis, they have not returned to pre-crisis levels.[351]

554. In argument, ATCO Electric stated that there simply has been no material change in circumstances since the close of the record in Decision 2009-216, that any change to its capital structure would be inconsistent with Decision 2009-216, and as such ATCO Electric's transmission and distribution capital structure should not be changed at this time. ATCO Electric further stated that to reduce the common equity component of ATCO Electric's capital structure would only serve to exacerbate the problems ATCO Electric is attempting to address in the context of its request to include transmission direct assigned CWIP in rate base and adopt the FIT methodology for transmission federal income taxes.[352]

555. The UCA also stated in argument that the credit crisis is over and that financial markets have normalized. The UCA cited that the improvement in the Canadian economy, the re-emergence of high yield bonds and asset-backed commercial paper, and the reduction in volatility are all evidence that the credit crisis has normalized in Canada.[353]

556. In their evidence, Drs. Kryzanowski and Roberts made the following conclusions, which the UCA reaffirmed in argument:

> …the business risks faced by ATCO T7ransmission [sic] including the risk of asset replacement associated with the capital build … is unchanged since (since Decision 2009-216). Examining benchmarks for equity thickness for Canadian utilities, we demonstrate that these are unchanged from the 2009 hearing. Combining unchanged business risk with unchanged benchmarks leads us to the conclusion that the equity thickness awarded ATCO Electric Transmission of 36% (including 2% for the repricing of risk in the credit crisis and 1% for the risk of the capital build) remains in our view, a generous capital structure.

[350] Exhibit 179.01, AE argument Module 2, paragraphs 49, 51, and 52.
[351] Exhibit 179.01, AE argument Module 2, paragraph 50 and 53.
[352] Exhibit 179.01, AE argument Module 2, paragraphs 56 and 57.
[353] Exhibit 178.01, UCA argument Module 2, paragraphs 12-16.

> …the current treatment under which FIT are excluded, there is no CWIP-in-RB, and the present capital structure of 36% equity is maintained do not result in credit metrics that are unacceptably low. Second, we also consider a scenario in which FIT is excluded, 25% of CWIP is included in rate base and there is a 1% decrease in the generous equity thickness awarded in Decision 2009-216 (especially given current credit conditions). Our calculations reveal that this scenario produces highly acceptable credit metrics.[354]

557. ATCO Electric in reply argument stated that there has been extensive evidence provided by Ms. McShane that confirms that, while market conditions have improved dramatically from the depths of the economic crisis, there have only been marginal changes since the close of the record in the 2009 Generic Cost of Capital proceeding. The decisions rendered by the Commission in that proceeding were clearly based on the best evidence before it at the time. No material change has occurred which would warrant an alteration of the capital structure awarded to ATCO Electric in Decision 2009-216.[355] ATCO Electric further stated that with regard to the UCA's alternate proposal of allowing 25 per cent CWIP in rate base, no FIT, and a 1 per cent decrease in equity thickness, this alternative does not provide any relief to the concerns regarding ATCO Electric's transmission credit metrics and as such, this is not an acceptable solution and should be rejected.[356]

### Commission findings

558. The Commission notes the UCA's argument that the Commission had, in Decision 2009-216, increased the base equity ratio of all the utilities by two per cent in recognition of the credit crisis,[357] which it argued has now largely abated, obviating the need for this two percent. In fact the section of the decision quoted by the UCA in its argument at paragraph four indicates that the credit crisis was only one of four factors that led to the two per cent increase.

559. The Commission notes that the 2011 Generic Cost of Capital hearing will closely follow the close of this proceeding. Given the comprehensive nature of the 2011 Generic Cost of Capital proceeding and its proximity to this proceeding, the Commission defers its decision on the capital structure of ATCO Electric to that proceeding. The Commission accepts ATCO Electric's use of the equity ratios approved in Decision 2009-216 of 36 per cent for transmission and 39 per cent for distribution as placeholders, pending the determinations that will be made in the 2011 Generic Cost of Capital proceeding.

## 8 Placeholders and deferral accounts

560. In addition to the discussion found below, detailed discussions regarding individual deferral accounts may also be found in their relevant sections throughout this decision.

561. In the application, ATCO Electric indicated that it was seeking placeholders and deferral accounts for the following items:

[354] Exhibit 81.02, Redacted UCA evidence on CWIP and FIT, paragraphs 219 and 220.
[355] Exhibit 183.01, AE reply argument Module 2, paragraph 41.
[356] Exhibit 183.01, AE reply argument Module 2, paragraph 44.
[357] Exhibit 178.01, UCA argument Module 2, paragraph 4.

Decision **2011-474**

AUC

Alberta Utilities Commission

# 2011 Generic Cost of Capital

**December 8, 2011**

registered as the Independent System Operator), the Consumers' Coalition of Alberta (CCA), the Office of The Utilities Consumer Advocate (UCA), and the Canadian Association of Petroleum Producers (CAPP).

12. Expert evidence was sponsored by several parties. The Utilities sponsored:

Ms. Kathleen McShane , B.A., M.A, MBA, CFA, President and senior consultant with Foster Associates Inc. of Bethesda, Maryland

Aaron M. Engen, B.A., LLB, MBA, Managing Director, Investment and Corporate Banking, Power & Utilities Group at BMO Capital Markets

CAPP sponsored:

Dr. Laurence Booth, B.Sc., M.A., M.B.A., D.B.A. of the University of Toronto.

The UCA sponsored, as a team:

Dr. Lawrence Kryzanowski, B.A., Ph.D., of Concordia University

Dr. Gordon S. Roberts, B.A., Ph.D., of York University

13. As indicated in the Commission's scope letter of December 16, 2010,[2] for expediency and in order to minimize costs, the complete record of the 2009 GCOC proceeding was incorporated into this proceeding. The complete evidentiary record of this proceeding is filed in the Commission's electronic system under Proceeding ID No. 833. The Commission considers that the close of record for this proceeding was September 9, 2011, which is the date on which reply argument was filed.

14. In reaching the determinations set out within this decision, the Commission has considered all relevant materials comprising the record of this proceeding, including the evidence and argument provided by each party. Accordingly, references in this decision to specific parts of the record are intended to assist the reader in understanding the Commission's reasoning relating to a particular matter and should not be taken as an indication that the Commission did not consider all relevant portions of the record with respect to that matter.

# 3 2011 return on equity

## 3.1 Introduction

15. The Commission has set out its findings in this section of the decision generally following the same structure as the return on equity section of Decision 2009-216.[3]

16. Parties to the proceeding were asked to address the ROE for 2011 because it had been anticipated that the ROE for 2012 was to be dealt with by way of a formula, or by some other

[2] Exhibit 11.

[3] Decision 2009-216: 2009 Generic Cost of Capital, Application No. 1578571, Proceeding ID. 85, November 12, 2009.

method, in the absence of a formula. However, some of the experts also addressed 2012 directly in their ROE evidence.

17. To satisfy the fair return standard, the Commission is required to determine a fair return on equity for the utilities. The Commission was again presented with a significant body of evidence on the tests to be considered when determining the fair ROE, a number of opinions on the proper methodology to be employed for many of the tests and, as a result, a wide range of proposed ROEs. Briefly, the record of the proceeding included evidence to support ROE estimates based on:

- changes in the financial environment since the 2009 proceeding
- the capital asset pricing model (CAPM)
- the discounted cash flow model (DCF) which was applied to proxy utilities as well as to the equity market overall
- other evidence on comparable investments
- ROE awards by other Canadian regulators
- market price-to-book values
- returns on high grade bonds
- the return expectations from pension and investment managers
- the impact of growth on the required ROE

18. On the basis of this evidence, the Commission was presented with the following recommended ROEs for 2011 and 2012.

**Table 1. Summary of ROE recommendations**

| | Recommended By the Utilities[4] (%) | Recommended by UCA[5] (%) | Recommended by CAPP (%)[6] |
|---|---|---|---|
| 2011 | 10.375 | 8.3 | 7.75 |
| 2012 | 10.375 | 8.4 | 8.15 |

19. In this decision, the Commission has established a generic ROE for 2011. In Section 4 dealing with the adoption of a formula for adjusting the ROE beyond 2011, the Commission has determined that it will not adopt a formula at this time and that the ROE for 2012 will be the same as the ROE for 2011.

### 3.2 Changes in the financial environment since Decision 2009-216

20. Dr. Booth submitted that the Canadian economy was recovering from the financial crisis while the U.S. economy was still weak.[7] He submitted that Canada was two years out of

4 Exhibit 209, Utilities argument, paragraph 122.
5 Exhibit 210, UCA argument, paragraphs 149 and 150.
6 Exhibit 207, CAPP argument, paragraph 114.
7 Exhibit 207, CAPP argument, page 4.

recession but still had a long way to go.[8] He indicated that the situation in the United States during the financial crisis was "horrendous" but that "now it's less stressful" and that the major impact of the financial crisis has passed. Dr. Booth stated that spreads are still higher in Canada than they were but there is no stress in the financial system in Canada and corporate bond yields have come down.[9] Dr. Booth noted the (then existing) risk that the United States would not increase its debt ceiling.[10]

21. The UCA submitted that there is no dispute that economic conditions have improved since the conclusion of the 2009 GCOC hearing in June 2009. It submitted that 30-year utility bond spreads have declined by 50 basis points since then, that the 2008-2009 crisis is over and has been over for two years, and that we are now in a more typical post-recessionary recovery that is distinguishable from the extraordinary crisis mere months before the 2009 hearing. The UCA also stated that economic parameters have improved significantly and for all practical purposes have "normalized."[11]

22. The UCA proposed that, because there is agreement that conditions have improved directionally since the end of the 2009 proceeding, financial conditions are not a justification for increasing the allowed ROE, as the Utilities would urge.[12]

23. The CCA noted that the intervener and utility experts agreed that capital markets have improved since 2009.[13]

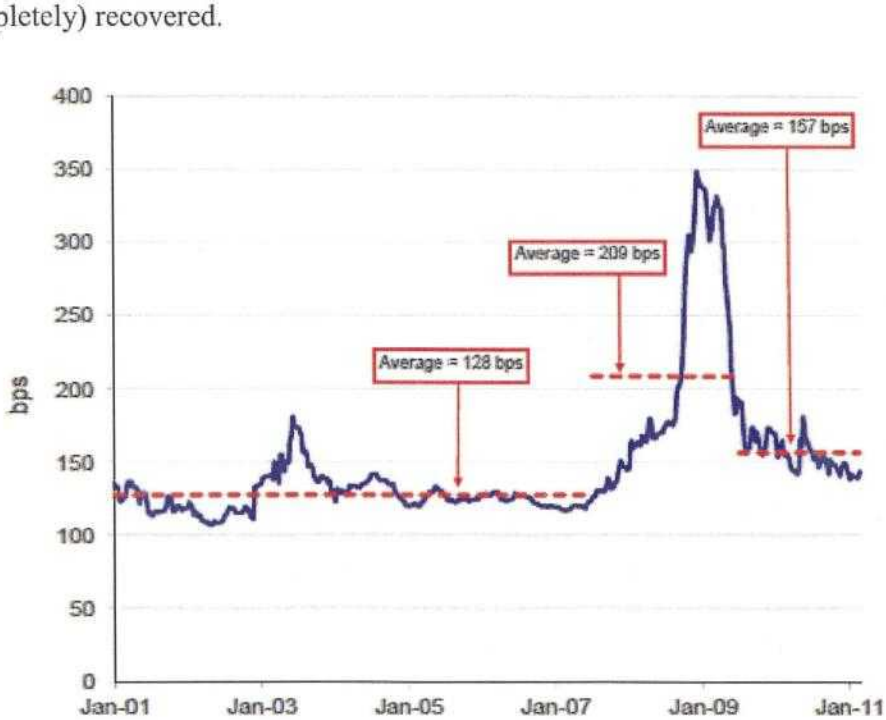
24. The Utilities argued that, although financial markets have stabilized to some degree relative to 2009, risk remains elevated and risk has been re-priced as evidenced by credit spreads.[14] They cited a World Economic Forum publication of January 2011 which had indicated there were ever-greater concerns regarding global risks and "the prospect of rapid contagion through increasingly connected systems and the threat of disastrous impacts."[15]

25. The Utilities noted that Dr. Booth had volunteered that there were significant risks remaining in the global financial system and that his 8.15 per cent recommendation for 2012 was 90 basis points higher than he had recommended in 2009 at the same 4.5 per cent long-term Canada bond yield forecast, in part due to continuing uncertainties.[16]

26. The following chart from Exhibit 172 illustrates how the 30-year bond spread for Canadian relatively pure-play regulated utilities had been relatively stable since 2001 but increased sharply (to unprecedented levels) during the financial crisis, and then largely (but not

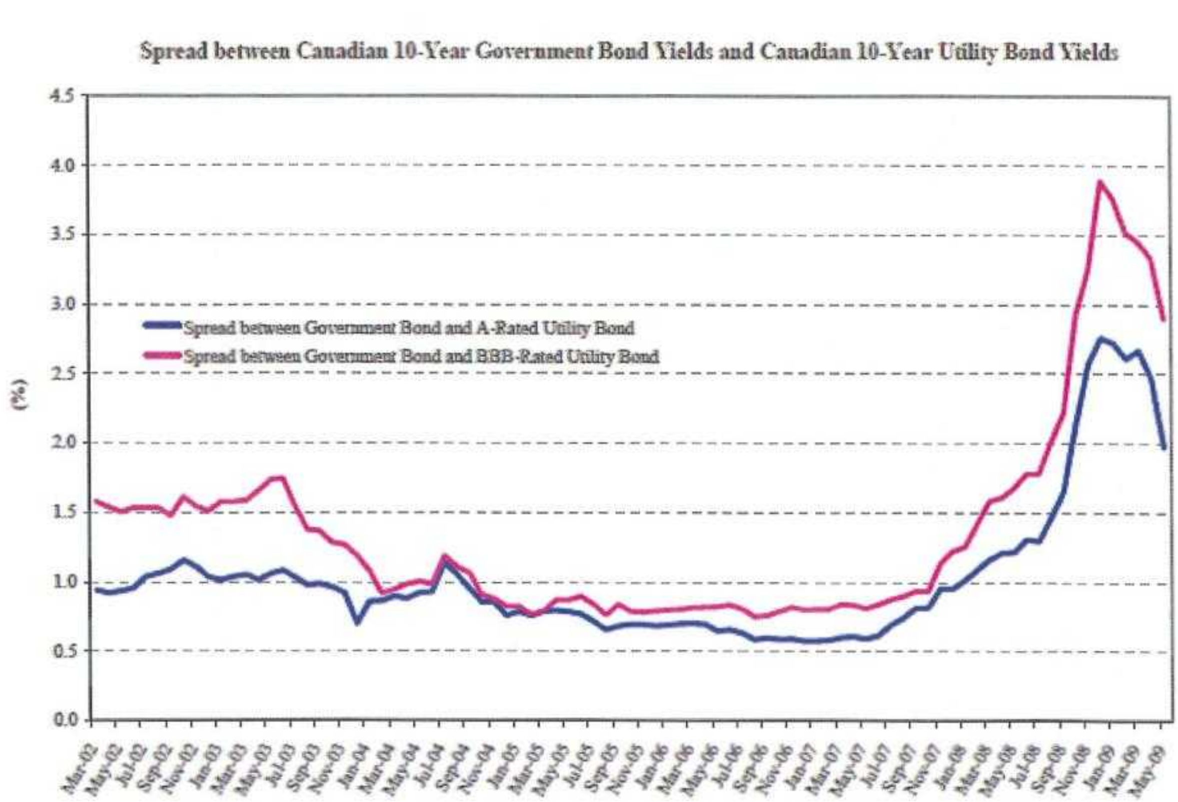
8 Exhibit 207, CAPP argument, page 6.
9 Exhibit 207, CAPP argument, page 11 and 12.
10 Exhibit 207, CAPP argument, page 13.
11 Exhibit 210, UCA argument, paragraphs 8, 10 and 11.
12 Exhibit 221, UCA reply argument, paragraph 5.
13 Exhibit 211, CCA argument, paragraph 15.
14 Exhibit 208, Utilities argument, paragraph 11.
15 Exhibit 208, Utilities argument, paragraph 25.
16 Exhibit 220, Utilities reply argument, paragraphs 19, 21 and 22.

completely) recovered.




27. For comparison, the Commission notes the following chart from paragraph 301 of Decision 2009-216, which illustrates utility corporate bond spreads prior to the credit crisis and during the credit crisis, up to the time of the 2009 hearing. It indicates that the recovery had begun by the end of the 2009 hearing.

Spread between Canadian 10-Year Government Bond Yields and Canadian 10-Year Utility Bond Yields




Source: Bloomberg as of May 29, 2009.

28. From the charts above, the Commission finds that corporate bond spreads had begun to recover at the time of the 2009 hearing but had far from fully recovered. The Commission also finds that, in contrast, by the time of the 2011 hearing, bond spreads had largely, although not completely, returned to historic levels.

### 3.3 Capital asset pricing model

29. CAPM is a well-accepted and theoretically-grounded economic model for valuing securities based on the relationship between non-diversifiable risk and expected return. CAPM is based on the principle that investors need to be compensated in two ways: for the time value of money and for risk. In the model, the time value of money is represented by the rate that compensates the investor for placing money in a risk-free investment over a period of time (the risk-free rate). The second part of the model considers risk and estimates the compensation that the investor needs for taking on the risk that the expected return will not be realized. This element of risk is calculated by taking a risk measure (beta) based on the statistical relationship between the historical returns for the investment security relative to the historical returns for the market as a whole, over time. Beta is a risk measure that describes how sensitive the expected return of a security is to the market. Hence, CAPM calculates the expected return for a security as the rate of return on a risk free security plus a risk premium.

30. Evidence to support proposed ROEs based on an application of CAPM was provided by Ms. McShane, Dr. Booth, and Drs. Kryzanowski and Roberts.

31. The following table sets out the recommended individual CAPM components and resulting ROE levels for each of the experts that presented evidence on CAPM.

Table 2. CAPM recommendations

| Expert Witness | Risk-free Rate (%) | MERP (%) | Market Return (%) | Beta | Adder | Flotation Allowance (%) | ROE (%) |
|---|---|---|---|---|---|---|---|
| Dr. Booth 2011 | 4.10 | 5.0 to 6.0 | 9.1 -10.1 | 0.45 -0.55 | 0.25 - 0.50 | 0.50 | 8.15 (7.5 - 8.8) |
| Dr. Booth 2012 | 4.50 | 5.0 to 6.0 | 9.5 -10.5 | 0.45 -0.55 | 0.25 - 0.50 | 0.50 | 7.75 (7.10 - 8.4) |
| Drs. Kryzanowski & Roberts[17] (At their equity ratio recommendation) | 4.20 | 5.2 | 9.4 | 0.52 | 0.90[18] | 0.50 | 8.3. |
| Drs. Kryzanowski & Roberts (At higher equity ratios) | 4.20 | 5.2 | 9.4 | 0.52 | | 0.50 | 7.4 |
| Ms. McShane | 4.25[19] | 7.25[20] | 11.5[21] | 0.65 | | | |

recommended.[26] For this reason, the Commission included two CAPM ROE recommendations for Drs. Kryzanowski and Roberts in the table above. The Utilities submitted that Drs. Kryzanowski and Roberts' CAPM estimate was, by their own admission, insufficient for an A credit rating until they had made a credit metric adjustment.[27]

35. In considering the evidence on CAPM, the Commission reviewed the proposals on the individual components of CAPM, as well as each party's overall ROE estimate based on the CAPM approach. Each CAPM component, and the overall resulting CAPM estimates of ROE, are addressed below.

### 3.3.1 Risk-free rate

36. The CAPM analysis starts from a forecast of the risk-free rate.

37. Ms. McShane, on behalf of the Utilities, estimated the 2011-2012 average long-term Canada bond yield at 4.25 per cent.[28] This was an average of her 4.0 per cent forecast for 2011, based on the January 2011 Consensus Economics forecast and the December 2010 spread between the 30-year and 10-year Canada bonds, and her 4.5 per cent estimate for 2012 based on the most recent forecasts from major Canadian banks.[29]

38. Dr. Booth forecast a risk-free rate of 4.50 per cent for 2012, indicating that this was somewhat higher than his 2009 forecast, given that Canada is further along in its recovery. Dr. Booth had considered the Consensus Economics forecast, as well as that of the Royal Bank of Canada, and he discussed the views of the Bank of Canada. He forecast a rate of 4.10 per cent for 2011 but supported the use of 4.50 per cent for both 2011 and 2012.[30]

39. Drs. Kryzanowski and Roberts forecast the 30-year bond yield at 4.20 per cent for 2011 based on the Consensus Economics forecast and recently observed spreads between the 30-year and 10-year Canada bonds; adding 15 basis points for more recent movements in the 10-year yield.[31]

40. The UCA noted that all of the experts had applied judgment to arrive at a risk free rate similar to 2009, even though actual long-term Canada bond rates and the Consensus Economics forecast used in the National Energy Board's formula indicated a reduction of 60 basis points since 2009.[32]

41. The Commission notes that the latest available Consensus Economics forecast on the record, from July 2011, forecast a 10-year Government of Canada bond rate for October 2011 of 3.3 per cent and for July 2012 of 3.8 per cent.[33] Adding 50 basis points for the spread between the 10-year and the 30-year bond forecasts results in a 30-year forecast of 3.8 per cent for October 2011 and 4.3 per cent for July 2012.

26 Exhibit 210, UCA argument, paragraphs 75 and 78.
27 Exhibit 208, Utilities argument, paragraphs 48 -51.
28 Exhibit 208, Utilities argument, paragraph 55.
29 Exhibit 86.01, Kathleen McShane opinion, page 52, lines 1094 to 1104.
30 Exhibit 207, CAPP argument, page 16.
31 Exhibit 210, UCA argument, paragraph 25.
32 Exhibit 221, UCA reply argument, paragraph 34.
33 Exhibit 204.01.

42. The July 2011 Consensus Economics forecast, referenced above, also indicated that the actual 10-year Government of Canada bond yield in July 2011 was 2.9 per cent. At the time of the 2009 hearing, the actual 10-year Canada bond interest yield was 3.5 per cent.[34] Therefore, the Commission notes that the 10-year Canada bond yield declined 60 basis points from the 2009 hearing to the 2011 hearing.

43. The Consensus Economics forecast has traditionally been used by the Commission and its predecessor to estimate the risk free rate. In 2009, the Commission found that a risk free rate in the range of 4.13 per cent to 4.50 per cent was reasonable, based on the Consensus Economics forecast at that time. Based on the Consensus Economics forecasts and the July 2011 actual 10-year interest rate of 2.9 per cent, on the record of this proceeding, the Commission considers that a long-term bond yield forecast of 3.4 per cent to 3.8 per cent for 2011 is reasonable, considering the current volatility in rates and the 60 basis point decline since 2009.

### 3.3.2 Market equity risk premium

44. The next element of the CAPM analysis is the market equity risk premium (MERP). Parties recommended a number of market equity risk premiums.

45. The Utilities argued that an arithmetic average market equity risk premium should continue to be used, rather than the lower geometric average.[35] Ms. McShane submitted that arithmetic average returns have been 1.7 per cent higher than the geometric average in Canada since 1924 and 2.0 per cent higher in the U.S. since 1926. She submitted that the arithmetic average was 1.3 per cent and 1.5 per cent higher than the geometric average for Canada and the U.S., respectively, in the post war period.[36]

46. Ms. McShane submitted that historic risk premium data should not be used without considering that today's environment may be different.[37] In support of this, she relied on her analysis which, she submitted, demonstrated that equity returns and risk premiums have tended to be higher when (as now) bond interest rates are low.[38] She also submitted that her analysis demonstrated that equity returns have been higher when (as now) inflation is low.[39] The Utilities argued that Drs. Kryzanowski and Roberts' proposed adjustment formula implicitly suggests that the equity market return does not decline with lower interest rates, which supports the Utilities' position.[40]

47. Dr. Booth estimated that the market equity risk premium is five per cent and indicated that a range of 5.0 to 6.0 per cent was reasonable.[41]

48. The UCA submitted that the use of a longer historical period can improve the accuracy of the market equity risk premium estimate in a statistical sense but may introduce errors because historical conditions may differ from today. In particular, the UCA submitted that trading costs and impediments to foreign diversification may explain higher historical risk premiums.

34 Exhibit 367.02 of Proceeding 85, 2009 Generic Cost of Capital.
35 Exhibit 208, Utilities argument, paragraphs 57 and 58.
36 Exhibit 86.01, Kathleen McShane opinion, page 52 lines 1269-1271.
37 Exhibit 86.01, Kathleen McShane opinion , lines 1083-1085.
38 Exhibit 86.01, Kathleen McShane opinion, page 49, Table 9.
39 Exhibit 86.01, Kathleen McShane opinion, page 54, Table 12.
40 Exhibit 219, Utilities reply argument, paragraph 38.
41 Exhibit 207, CAPP argument, page 17.

Drs. Kryzanowski and Roberts estimated the market equity risk premium at 5.2 per cent using a weighting of 75 per cent geometric average and 25 per cent arithmetic average and considering various historical periods in both Canada and the U.S.[42]

49. Drs. Kryzanowski and Roberts submitted that Ms. McShane's evidence failed to test whether this inverse relationship had been expected by investors, that she had not provided tests of significance and that she failed to adjust for unique past events including wage and price controls.[43] Drs. Kryzanowski and Roberts submitted that the most damaging argument against Ms. McShane's results were that they were inconsistent with the return expectations of investment professionals.[44] However, the Commission notes that the "different results" that Drs. Kryzanowski and Roberts noted, based on geometric returns, still indicated equity returns that were inversely correlated to inflation.[45]

50. Ms. McShane estimated that the market risk premium, at her forecast 4.25 per cent long-term Canada bond yield, was 6.5 per cent to 8.0 per cent or, using the mid-point, approximately 7.25 per cent.[46]

51. The Utilities submitted that equity market returns have not declined, but that achieved bond returns have increased as interest rates declined. They submitted that market risk premiums have not declined when measured against the bond income returns which, they argued, is the risk-free rate which should be used in the CAPM since it is the risk free portion of bond returns.[47] The Commission notes that Ms. McShane's equity market risk premium was based on the premium over bond yields, rather than over bond total returns. The Commission also notes that, if the market equity risk premium is constant, then equity returns would also have been impacted by lower interest rates. For this reason, Ms. McShane's proposal appears to compare a return on bonds which excludes capital gains caused by lower interest rates, to a return on equities that may include capital gains directly caused by lower interest rates. This does not appear to be consistent. The Commission is not convinced that it should base the market equity risk premium on bond income-only returns, rather than bond total returns, which is the traditional approach.

52. The Commission notes that long-term average data on achieved historical market risk premiums are usually used to estimate the required market equity risk premium going forward. However, in this proceeding, Ms. McShane has provided evidence that the market equity risk premium varies inversely with interest rates and inflation, and the UCA noted that using data from longer periods of time could introduce errors if historical conditions differ from those of today. For these reasons, the Commission is not prepared to use the long-term historical market risk premium as the applicable market equity risk premium for 2011, given that the risk free rate is far below its long-term historical average. The Commission also considered ongoing arguments about whether the geometric or the arithmetic average risk premium should be used, the observation that realized equity risk premiums were not necessarily the risk premiums that investors had expected, and the possibility that historic realized premiums are not necessarily reflective of future expectations.

42 Exhibit 210, UCA argument, paragraphs 27 and 30.
43 Exhibit, 142.02, rebuttal evidence of UCA, paragraphs 27 to 37.
44 Exhibit, 142.02, rebuttal evidence of UCA, paragraph 38.
45 Exhibit, 142.02, rebuttal evidence of UCA, paragraph 34.
46 Exhibit 86.01, Kathleen McShane opinion, page 55, lines 1341-1342.
47 Exhibit 220, Utilities reply argument, paragraphs 34 and 35.

53. The Commission has explored the relationship, discussed by Dr. Booth, of the market return, the utility return and the market equity risk premium implied by ROE formulas that allow the utility ROE to change with interest rates, as set out in tables 3 and 4 below.

**Table 3. Formula results when utility ROE changes at 75 per cent of change in risk free rate and beta is 0.55**

| Risk free rate | Beta | Implied market risk premium | Implied market return | Formula utility return | Note |
|---|---|---|---|---|---|
| **5.0%** | **0.55** | **5.00%** | **10.00%** | **7.75%** | **Initial ROE** |
| 6.0% | 0.55 | 4.55% | 10.55% | 8.50% | Formula Result |
| 7.0% | 0.55 | 4.09% | 11.09% | 9.25% | Formula Result |
| 4.0% | 0.55 | 5.45% | 9.45% | 7.00% | Formula Result |
| 3.0% | 0.55 | 5.91% | 8.91% | 6.25% | Formula Result |

Source: Commission staff

57. The Commission understands that actual long-term interest rates are near historic lows. At the Commission's estimated risk-free rate of 3.4 per cent to 3.8 per cent, the 30-year Government of Canada bond yield would be at the lower end of its historic range. In this circumstance, the Commission considers that it would not be correct to assume that the currently expected market equity risk premium is necessarily equal to its long-term average value.

58. Considering all of the above, the Commission finds that the expected market equity risk premium today may be higher than its' historic average, due to today's low interest rates. The Commission accepts that the market equity risk premium today may reasonably be as high as the 7.25 per cent mid-point of Ms. McShane's estimate.

59. The market equity risk premium from each expert's CAPM forecast is provided in Table 2 above. These range from 5.0 to 7.25 per cent. The Commission finds that a reasonable range for the market equity risk premium is 5.0 per cent to 7.25 per cent.

### 3.3.3 Beta

60. The next element of the CAPM analysis is the beta. Beta is a statistical measure describing the relationship of a stock's return with that of the stock market as a whole. In the Commission's view, the proper beta to use is that which represents the relative risk of stand-alone Canadian utilities. Past data (with or without adjustment) is usually used to estimate the reasonably expected beta going forward.

61. Ms. McShane used an adjusted beta to account for empirical studies that show that low beta stock returns would otherwise be under-estimated. Ms. McShane adjusted beta based on her own analysis of the adjustment required to explain historically achieved Canadian regulated company returns.[48] The Utilities proposed a beta in the range of 0.65 to 0.70.

62. The Utilities noted Ms. McShane's position that total risk, and not just diversifiable risk, should be considered for an undiversified investor, such as a utility investing in hard assets.[49] The Commission does not agree. The Commission's objective is to establish a market ROE for an investment of equivalent risk, held in a diversified market portfolio, because this emulates the conditions under which utilities raise equity capital.

63. The Utilities also noted that Dr. Fernandez (whose work had been cited by Dr. Booth) had provided evidence that the CAPM does not work and had concluded that historical betas are useless to estimate the expected return of companies.[50] However, the Commission continues to hold the view that CAPM is a theoretically sound and useful tool, among others, for estimating ROE.

64. The Utilities submitted that low risk utilities may not necessarily require a lower return than the overall market, when their higher financial leverage and risk is considered.[51] In the Commission's view, while a utility typically has higher financial leverage than a typical company on the stock market, it also has a correspondingly higher capacity for leverage due to its lower business risk. In the Commission's view, estimates of beta for utilities are estimates of utility risk relative to the market and already take into account the higher leverage of utilities.

48 Exhibit 208, Utilities argument, paragraph 66.
49 Exhibit 220, Utilities reply argument, paragraph 39.
50 Exhibit 220, Utilities reply argument, paragraph 40.
51 Exhibit 220, Utilities reply argument, paragraph 61.

65. Dr. Booth estimated that the Canadian stand-alone utility beta continues to be 0.45 to 0.55, the same range as he estimated in 2009. Dr. Booth based this conclusion on the performance of Canadian utility holding companies during the credit crisis, and the actual betas of low-risk U.S. utilities.[52]

66. Drs. Kryzanowski and Roberts submitted that a reasonable beta is 0.52. This was unchanged from their 2009 estimate and was based on observed betas.[53]

67. In 2009, the Commission found that a reasonable range for beta was 0.50 per cent to 0.63 per cent. Based on the 2011 evidence, the Commission is not persuaded to materially alter its finding from 2009. The Commission finds that a reasonable beta estimate is 0.50 per cent to 0.65 per cent.

### 3.3.4 Flotation allowance

68. The final element of the CAPM analysis is the flotation allowance. The parties all agreed that a flotation allowance is normally included in the allowed return to account for administrative costs and equity issuance costs, any impact of under-pricing a new issue, and the potential for dilution. Historically, the Commission and its predecessors have allowed 0.50 per cent additional return on equity to account for the costs of flotation and to better ensure that the investor can expect to receive at least the required return.

69. In the Commission's view, the flotation allowance also applies, for the same reasons, to the DCF method and all other estimates of the investor's required return. The reason for this is that, if a utility has flotation or issuing costs which it cannot claim as regulated expenses, then the utility needs to earn more than the investors required return in order to cover these added costs.

70. Dr. Booth continued to apply the traditional 0.50 per cent flotation allowance.[54]

71. Drs. Kryzanowski and Roberts added the standard and traditional 50 basis points allowance. They explained that only 10 basis points were related to cost but added 40 basis points for flexibility based on common regulatory practice in Canada.[55]

72. Ms. McShane, for the Utilities, recommended a higher flotation allowance of 100 basis points to recognise the difference between the market value capital structures of proxy companies and the book value capital structures used by the Commission.[56]

73. The Utilities noted Ms. McShane's evidence that the DCF and equity risk premium models represent conceptually different ways in which investors may approach estimating the return they require on the market value of an equity investment. She had submitted that, while the DCF and risk premium tests estimate the return required on the market value of common equity, regulatory convention applies that return to the capital invested in the book value of the

52 Exhibit 78, evidence of Laurence D. Booth, pages 56 and 57.
53 Exhibit 210, UCA argument, paragraph 54.
54 Exhibit 207, CAPP argument, page 19.
55 Exhibit 81.02, prepared testimony of Drs. Kryzanowski and Roberts, paragraph 103.
56 Exhibit 209, Utilities argument, paragraph 83.

assets included in rate base. She submitted that the determination of a fair return on book equity needs to recognize that distinction.[57]

74. The UCA submitted that the Commission should continue to apply market returns to a book value rate structure in accordance with the 2004 Generic Cost of Capital Decision.[58]

75. The Commission does not agree with Ms. McShane's argument for increasing the flotation allowance above the historically allowed 0.50 per cent. Arguments that a market return should be applied to a market value based rate base, rather than a book value rate base, are circular since the market value is clearly dependent on the awarded return.

76. Accordingly, the Commission finds that the usual regulatory convention of awarding a flotation allowance of 0.50 per cent continues to be reasonable.

### 3.3.5 The

capital indirectly. In her view, DCF measures "what is" while CAPM estimates the required return on the market value of common stock on a "what should be" basis.[60]

82. Drs. Kryzanowski and Roberts applied the DCF method to the market as a whole and arrived at a return estimate for the overall equity market of 8.0 per cent.[61]

83. Dr. Booth stated that the DCF estimate of ROE for the Standard & Poor's (S&P) 500 utilities sub-index was 8.98 per cent.[62] Dr. Booth applied the DCF method to the Canadian equity market as a whole and found it indicated a required investor return of 8.2 to 8.4 per cent. This did not include a flotation allowance. Dr. Booth indicated that this represented a minor under-estimation due to current recession conditions and proposed that growth coming out of the recession would be higher.[63]

84. The following table sets out the individual DCF components and resulting ROE levels proposed by each of the parties that presented evidence on the DCF model.

60 Exhibit 86.01, Kathleen McShane opinion, pages 75 and 43.
61 Exhibit 210, UCA argument, paragraph 96.
62 Exhibit 78, evidence of Laurence D. Booth, paragraph 153 CAPP Argument, page 20.
63 Exhibit 78, evidence of Laurence D. Booth, paragraph 152.

Table 6. Summary of DCF estimates

| Expert Witness | Dividend yield (%) | Stage 1 growth rate (%) | Stage 2 growth rate (%) | Final growth rate (%) | Investor required ROE (%) |
|---|---|---|---|---|---|
| DCF Applied to the Equity Market Overall | | | | | |
| Dr. Booth overall Canadian Market[64] | 2.45 | | | 5.6 | |

85. In 2009, the Commission rejected the use of long-term or terminal growth rates for utilities that exceed estimates of nominal dollar GDP growth. For 2011, there was no indication that the terminal growth rate forecasts exceeded reasonable estimates of nominal GDP growth.

86. In 2009, the Commission expressed concern about the potential upward bias in analysts' growth estimates.[75] However, Ms. McShane argued that, as long as investors believe the optimistic forecast, they would price the securities lower (resulting in a lower dividend yield) and the DCF test would still be an unbiased estimate of investor required returns. She indicated that this proposition had been successfully tested and described three tests, including the fact that such growth estimates have averaged less than GDP growth.[76] In the Commission's view, this line of reasoning does not resolve the issue because there is no evidence that investors believe optimistic forecasts. Therefore, the Commission remains concerned with the potential upward bias in analysts' growth estimates.

87. In 2009, the Commission also expressed concern about using proxy companies in a DCF analysis that are utility holding companies engaged in significant unregulated activities.[77] The Commission notes that Ms. McShane's Canadian sample consists of Canadian Utilities Limited, Emera Inc., Enbridge Inc., Fortis Inc. and TransCanada Corp. Of these, the Commission continues to consider only Emera Inc. and Fortis Inc. to be relatively free of unregulated activities. The Commission notes that the DCF results were 9.3 per cent for Emera Inc., using the three stage estimate, and 8.8 per cent for Fortis Inc., also using the three stage estimate.

88. The results above appear to suggest that investors expect a return of about 9.0 per cent on utility investments, assuming investors agree with analysts' growth forecasts. The Commission also notes that the DCF applied to the overall market suggested returns in the range of 7.1 to 10.1 per cent.

89. As explained above, the Commission considers that the DCF results should be adjusted to include flotation costs. As with the CAPM analysis, the Commission has adjusted the DCF results to include a 0.50 per cent flotation allowance

90. Overall, the Commission finds the 2011 results of the DCF analyses presented in the proceeding suggest a range of allowed ROEs for Canadian stand-alone utilities of 8.8 to 9.5 per cent, assuming that the equity ratio has been set to target a credit rating in the A range. However, as noted above, the Commission remains concerned about the potential impact of optimistic growth forecasts in this result.

### 3.5 Market returns on comparable investments

91. In AUC-ENGEN-09 (Exhibit 138), Mr. Engen provided data for certain Canadian energy infrastructure companies and included the price/earnings (P/E) ratios, the dividend yield, the price-to-book ratios and the ROEs. The median company in this group had a P/E ratio of 21.1, which equates to an earnings yield of 4.7 per cent. The median dividend yield was 5.2 per cent, which, because it is higher than the earnings yield, indicates that more than 100 per cent of the accounting earnings were being paid out, for the median company. The median price-to-book ratio was 2.1 times and the median ROE was 10.5 per cent. The Commission recognizes that

75 Decision 2009-216, paragraph 269.
76 Exhibit 86.01, Kathleen McShane opinion, page 77, lines 1843-1850.
77 Exhibit 86.01, Kathleen McShane opinion, page 77, lines 1843-1850.

infrastructure companies may also be able to pay out cash flows from depreciation and future income taxes that are in excess of earnings (at least temporarily, until long-lived assets need to be replaced).

92. The UCA submitted that Mr. Engen's evidence on certain Canadian energy infrastructure firms showed price-to-book values well in excess of 1.0, with the median and mean P/E ratios over 20, implying an earnings yield of five per cent. The UCA acknowledged that this did not account for growth and was not necessarily indicative of an appropriate allowed ROE, but submitted that it did indicate that investors in these shares were content with the firms having earnings yields in the range of five to six per cent of their market values which, it submitted, suggests that the required returns for utility investors are nowhere near the levels proposed by Ms. McShane.[78]

93. In the Commission's view, it is possible that part of the reason for the high P/E ratios is that, similar to the case with bonds, the higher prices and lower earnings and cash yields are an indication that the market required return has fallen. Another possibility is that investors expect to ultimately receive substantially more than the median earnings yield of 4.7 per cent and more than the median cash yield of 5.6 per cent, due to growth. However, with more than 100 per cent of the earnings being paid out in dividends, the sustainable growth formula (growth equals ROE times the proportion of earnings retained) would suggest that there will be minimal or no growth. Investors may still have legitimate expectations for growth, perhaps based on past experience. The sustainable growth formula assumes a constant ROE and does not take into account the ability to issue new shares and invest that money on an accretive basis. It also does not account for the fact that these infrastructure companies (with long-lived assets) may be able to invest some of the depreciation cash flows and future income tax cash flows to fund growth. Ultimately, however, one would assume that depreciation cash flows will be needed to replace existing assets.

94. In the Commission's view, the data provided by Mr. Engen on Canadian infrastructure companies does not provide much support for the case that investors should reasonably expect to earn double digit returns in these investments. It would require growth in the range of 4.8 per cent annually (added to the dividend yield of 5.2 per cent) to arrive at a 10 per cent expected return. With more than 100 per cent of the earnings being paid out as dividends, it is not clear where earnings growth beyond the rate of inflation would come from.

95. Overall, the Commission finds that the evidence is inconclusive on the return investors expect on these infrastructure companies, and there is insufficient evidence that these returns are sufficiently comparable to the utility investments at issue in this proceeding.

### 3.5.1 Historic returns

96. In her evidence, Ms. McShane examined the historic returns for utilities. According to Ms. McShane, the historical average utility return, in both Canada and the U.S., has clustered in the 11.0 to 12.0 per cent range. She submitted that investors tend to base their expectations on experienced returns and that there was no long-term upward or downward trend. She submitted that the utility returns had varied by approximately 50 per cent of the change in long-term government bond yields.

78 Exhibit 210, UCA argument, paragraph 103.

97. Ms. McShane also used this historical data on the experienced returns of utilities to provide an additional equity risk premium estimate derived from the observed equity risk premiums achieved by utilities. This resulted in an equity risk premium of 6.25 to 6.5 per cent. At Ms. McShane's forecast Canada bond yield of 4.25 per cent, the indicated utility cost of equity was approximately 10.50 to 10.75 per cent or 11.5 to 11.75 per cent after adding her recommended 1.0 per cent for flotation.

98. The UCA noted that Ms. McShane had provided evidence indicating that utility investors have made returns that are higher than the overall market and stated that, at best, this was evidence that regulators have over-estimated the risk-adjusted cost of equity (and thereby provided a return that is too high).[79]

99. The Commission agrees with the UCA that part of the reason for higher historic returns may be that allowed returns have been above the actual ROE that investors expected and required for investments of comparable risk. The Commission finds that the evidence on historic returns is inconclusive with respect to the return investors expect on comparable investments.

### 3.6 Returns awarded by other regulators

100. The Utilities submitted that the mean and median equity returns allowed by Canadian utility regulators, excluding Alberta, are 9.62 per cent and 9.66 per cent, respectively. The Utilities noted that some of these returns involved negotiated settlements but they argued that the results from a range of negotiated settlements provide insight as to reasonable returns.[80] The Utilities submitted that this comparison indicates that the current ROE of 9.0 per cent is too low.

101. The Commission notes that these awarded returns range from 8.38 per cent for Newfoundland Power for 2011 to 10.15 per cent for Pacific Northern Gas–West for 2011. The Commission also notes that these awarded returns would have pre-dated the drop in interest rates that occurred in August 2011 and may have reflected premiums for the 2008-2009 credit crisis.

102. The Commission also gives no weight to the equity returns arising from negotiated settlements. The Commission recognizes that, in a negotiated settlement, there are various trade-offs to which parties have agreed that can skew the awarded ROE.

103. Accordingly, the Commission gives no weight to the returns awarded by other regulators and included on the record of this proceeding.

### 3.7 Price-to-book ratios

104. An equity price-to-book ratio (also called market-to-book ratio) is calculated by dividing the current market price of a stock by its current book value per share. It is often used to compare a stock's market value to its book value. There was considerable debate during the proceeding as to the relevance, if any, of price-to-book ratios.

79 Exhibit 210, UCA argument, paragraphs 104 and 105.
80 Exhibit 209, Utilities argument, paragraphs 101-103.

105. The Utilities provided a variety of arguments as to why price-to-book ratios of utility holding company shares and those derived from the acquisitions of utilities are not indicative of required returns or the cost of capital.[81]

106. In regards to the price-to-book value of the 2001 AltaLink transaction, the Utilities referred to AUC-ENGEN-07. In that response, Mr. Engen indicated that the price-to-book value at the time of the purchase was 1.93. He also indicated that subsequent additional investments by AltaLink (which are made at book value) have reduced the ratio to 1.26. However, the Commission notes that this 1.26 estimate is not calculated as the current value of AltaLink divided by its current book equity and does not appear to be a relevant figure.

107. In his rebuttal evidence, Dr. Booth provided an appendix of basic financial relationships and stated "[i]f a Board then accepted a high market-to-book ratio in any way, it is implicitly indicating that it is awarding an unfair allowed ROE and is being derelict in the exercise of its statutory responsibilities." He noted that an exception is to allow a ratio slightly above 1.0 to prevent dilution on a share issue.[82]

108. Dr. Booth stated that the observed price-to-book ratios indicate allowed returns have generally been higher than the fair return. CAPP submitted that the bidding war for Central Vermont Power resulted in an equity price-to-book ratio at or above 2.0. CAPP also noted that AltaLink itself indicated a price-to-book ratio of 1.58 regarding the 2011 sale of a portion of AltaLink.[83]

109. In their evidence, Drs. Kryzanowski and Roberts indicated the ROE for Fortis Inc. (which they indicated was the only Canadian relatively pure-play utility, considered by the Commission in 2009, that trades on the market) is generous because Fortis Inc.'s price-to-book ratio is well above 1.0, despite substantial intangible assets (goodwill), indicating the ROE is above the cost of equity.[84] They submitted that high utility price-to-book values in the U.S. mean the utility returns on market value have been single digit. They also submitted that the recent AltaLink transaction, involving the purchase by the SNC-Lavalin Group Inc. of the minority interest in AltaLink, represents a low ROE for the purchaser.

110. The UCA submitted that there did not appear to be any dispute that, in theory, a market-to-book ratio significantly above 1.0 indicates that the earned and allowed ROE is higher than the true cost of capital. The UCA also submitted that another fact that did not seem to be in dispute was that the actual market-to-book ratios for utility shares, and in utility purchase transactions, are almost always considerably higher than 1.0.[85] The UCA submitted that the fact that the observed market-to-book ratios are so significantly above 1.0 strongly suggests that prevailing allowed returns are too high, and probably by a considerable amount.[86]

111. The UCA submitted that utility shares trade in the market at a value almost twice the book value of utility assets.[87] The UCA noted that Drs. Kryzanowski and Roberts had estimated the price-to-book value of the 2011 AltaLink transaction to be 1.95, with goodwill included in

81 Exhibit 209, Utilities argument, paragraphs 106-113.
82 Exhibit 145.01, update and rebuttal evidence of Laurence D. Booth, page 44.
83 Exhibit 207, CAPP argument, paragraphs 57 and 58.
84 Exhibit 81.02, prepared testimony of Drs. Kryzanowski and Roberts, paragraph 15.
85 Exhibit 210, UCA argument, paragraphs 108 and 109.
86 Exhibit 210, UCA argument, paragraph 119.
87 Exhibit 210, UCA reply argument, paragraph 53.

the book value, and 3.39 with goodwill excluded.[88] The Commission considers that the relevant price-to-book value for a pure-play regulated utility with no unregulated business is the price to the book value of the portion of rate base supported by equity, which would exclude goodwill from book value since goodwill is not allowed in rate base.

112. Decision 2009-216 stated that:

> The Commission considers that a price-to-book ratio of approximately 1.2 for a stand-alone utility would generally indicate that the return is at least fair. However, the Commission is unable to derive any useful information about the price-to-book ratios of stand-alone utilities from the price-to-book ratios for utility holding companies.
>
> ...
>
> The (equity) price-to-book ratio for the 2007 Fortis acquisition of Teresen Inc. was discussed on the record of the proceeding as a potential indicator of the price-to-book ratio for a stand-alone utility. However, there was considerable disagreement as to the correct calculation of the price-to-book value for this transaction. Price-to-book values in the range of 1.27 to 3.99 were provided. Despite the lack of agreement with respect to the exact calculation, the evidence is that the price paid for Teresen Inc. was at a price-to-book ratio above 1.2. It appears therefore that the awarded return for Teresen was at least fair, at the time of the transaction. However, there is ample evidence on the record that conditions in the market have changed significantly since the Teresen transaction in 2007, and the Commission cannot rely on this transaction as indicative of a fair return for 2009.[89] (footnotes omitted)

113. The Commission notes the evidence that pure-play regulated Canadian utility assets have historically been valued at equity price-to-book value ratios significantly above 1.0, including the 2011 AltaLink transaction, the 2007 Fortis Inc. purchase of Terasen Inc., the 2004 Fortis Inc. purchase of Aquila (referenced in Decision 2004-052[90]) and AltaLink's 2001 purchase of the transmission assets of TransAlta.

114. In Decision 2009-216, the Commission indicated it could not rely on such transactions, specifically the 2007 Terasen transaction, as being indicative of a fair return for 2009. The situation in 2009 was that, during the credit crisis, stock markets declined substantially, and it was clear that the higher levels of price to book ratios observed in the above transactions, would have declined during the credit crisis. The subsequent 2011 AltaLink transaction following the recovery in stock market prices may be evidence that pure-play regulated Canadian utilities are once again valued at high price-to-book ratios. The question then becomes; do high price-to-book ratios indicate that regulated returns have been above the market required level?

115. The Commission's predecessor indicated in Decision 2004-052 that strategic factors, growth and geographic diversification might explain the payment of a premium. There was some debate in this proceeding on the reasons why investors have been willing to pay significant premiums to purchase pure-play regulated utility assets.

88 Exhibit 210, UCA argument, paragraph 120.

89 Decision 2009-216, paragraphs 295 and 297.

90 Decision 2004-052: Generic Cost of Capital, AltaGas Utilities Inc., AltaLink Management Ltd, ATCO Electric Ltd. (Distribution), ATCO Electric Ltd. (Transmission), ATCO Gas, ATCO Pipelines, ENMAX Power Corporation (Distribution), EPCOR Distribution Inc., EPCOR Transmission Inc., FortisAlberta (formerly Aquila Networks), NOVA Gas Transmission Ltd., Application No. 1271597, July 2, 2004.

116. Mr. Engen proposed that the opportunity for cross-border purchasers to deduct the same interest in two countries may explain the premiums. Dr. Booth noted, and the Commission agrees, that in the transactions referenced above there were no cross-border purchasers involved. Mr. Engen proposed that the value of expected growth in rate base assets may encourage a premium. However, Dr. Booth submitted that financial theory indicates that growth is of value only if the expected ROE exceeds the fair rate of return. The Commission agrees with this. If there were ample opportunities to invest at the same or higher returns elsewhere, then the opportunity to grow rate base has no value.

117. Mr. Engen offered that a premium may signal an expectation of higher regulated return levels in the future. Dr. Booth submitted that, if this were the case, it would suggest that the current return was too low and accordingly the current price-to-book ratio should be below one. The Commission agrees.

118. Mr. Engen argued that a premium may be paid if investors expected that operating efficiencies would lead to higher earnings. Dr. Booth submitted that, under regulation, cost savings are meant to be passed on to customers. However, the Commission recognizes that, under the current rate base rate of return regime, operating savings can result in earnings beyond the regulated return and investors are entitled to retain these earnings during a test year. This provides incentives for increased efficiencies, but these efficiencies are later realized by customers in the next test period. The Commission is also aware that many of the utilities it regulates frequently achieve operating efficiencies and earn returns beyond the allowed return.

119. Likewise, Mr. Engen suggested that performance-based regulation (PBR) opportunities may have incented investors to pay a premium. Dr. Booth submitted that this was partly correct, but that a price-to-book ratio of 1.8 would require very large, if not impossible, efficiencies. The Commission agrees that the opportunity to adopt performance based regulation may be a justification for a premium, given that the opportunity to retain earnings above the regulated return is enhanced under PBR.

120. Finally, Mr. Engen argued that access to attractive unregulated assets and collateral benefits or synergies, or access to new territory, or a desire to protect one's existing regulated franchise may be reasons to pay a premium. The Commission agrees that these may arguably be business reasons for the payment of a premium.

121. In the Commission's view, it would not be rational for investors to purchase a utility at a premium, unless it was of the view that it could earn at least a market rate of return on the investment despite paying the premium. The payment of premiums in such transactions for assets that are earning returns based on ROE awards that are allegedly below market would not appear to be rational. A possible conclusion is that such purchases, at substantial premiums, would indicate that the awarded returns were more than sufficiently attractive.

122. Again, the Commission finds, as it did in Decision 2009-216, that a price-to-book ratio of approximately 1.2 for a stand-alone utility would generally indicate that the return is at least fair. However, the Commission is unable to derive any useful information about the price-to-book ratios of stand-alone utilities from the price-to-book ratios of utility holding companies. With respect to the recent AltaLink purchase by the SNC-Lavalin Group Inc., given the above discussion, the Commission considers that there may be business reasons for this purchase that are not well understood. In these circumstances, it is difficult for the Commission to draw any

conclusions about the significance of this transaction to the establishment of a fair return on equity. Nonetheless, the Commission agrees with the observation that a market-to-book ratio significantly above 1.0 indicates that the earned and allowed ROE is higher than the true cost of capital. Estimates of the price to book ratio for the 2011 AltaLink transaction generally exceed 1.0 by a significant margin. This appears to be evidence that the allowed ROE at the time of the purchase was at least adequate.

### 3.8 Returns available on high grade corporate bonds

123. CAPP referenced the fact that in Decision 2009-216, the Commission concluded that the high corporate bond spreads at that time justified the addition of 50 basis points to the results derived from methodologies like CAPM that rely solely on historical data to estimate the equity premium above the risk free rate.[91]

124. Dr. Booth indicated that studies by the Bank of Canada have shown that 63 per cent of the increase in corporate spreads during the credit crisis was due to liquidity problems in the bond market and only 37 per cent was due to default risk. He argued it is only the default risk that affects equity investors.[92] Dr. Booth indicated that, in contrast to corporate bond liquidity, equity market liquidity had increased during the credit crisis and equity investors should not be rewarded for a liquidity problem in the bond markets that does not affect equity holders.[93]

125. Dr. Booth saw a justification for no more than 25 basis points at this time, in respect of higher than historical corporate bond spreads, but used a range of 25 to 50 basis points for this allowance.

126. The Utilities submitted that spreads on Canadian A-rated utility bonds, as at July 29, 2011, were at 141 basis points, which is well above the 95 basis point average for 2003 through 2007.[94]

127. In Decision 2009-216, the Commission stated:

> As has occurred throughout this Proceeding, the Commission must weigh conflicting expert testimony on various factors impacting the determination of a fair return for Alberta utilities. The Commission considers the increased high grade Canadian corporate bond spreads which occurred during the financial crisis and which continued to occur, albeit on a downward trend, at the close of the Proceeding demonstrate that there has indeed been some re-pricing of risk on debt securities. Equity investors in high grade rated companies have more default risk than do debt investors. An increase in debt investor return expectations ordinarily must be considered to result in an increase in return expectations for equity investors otherwise equity investors would not accept the incremental risk associated with equity ownership. The Commission finds that there is insufficient evidence on the record of the proceeding that illiquidity in the Canadian bond market during the financial crisis can account for a significant portion of the increased risk premium demanded by bond investors.
>
> It remains an open question whether corporate bond spreads will quickly, if ever, return to pre-financial crisis levels. In particular, it remains uncertain that the re-pricing of risk

91 Exhibit 207, CAPP argument, paragraph 61 referencing Decision 2009-216 at paragraph 311.
92 Exhibit 207, CAPP argument, paragraph 64.
93 Exhibit 207, CAPP argument, paragraph 70.
94 Exhibit 209, Utilities argument, paragraph 23.

> observed in high grade Canadian corporate bond spreads in the period up to the close of the Proceeding will end in either 2009 or 2010. In these circumstances, it is reasonable to conclude that the actual return expectations of utility equity investors in 2009 and 2010 would be at least 50 basis points higher than estimates of equity return expectations derived from methodologies like CAPM which rely solely upon historical data and the risk free rate.

128. As discussed in Section 3.2 above, the Commission considers that spreads have decreased from the 2009 levels but have not returned to their historic levels. The Commission also notes that it has set the top end of its CAPM market equity risk premium, assuming, on the basis of Ms. McShane's evidence, that the market equity risk premium may be higher than its historic average at this time of historically low interest rates. For these reasons, the Commission is not convinced that any addition to CAPM results is needed to account for the reduction in corporate bond spreads at this time.

## 3.9 Pension, investment manager and economist return expectations

129. In regards to the return expectations of pension and investment managers and others, the UCA submitted that, in December 2010, CIBC World Markets had forecast total returns on the Canadian market of 8.0 to 9.0 per cent over the next decade. In addition, the UCA submitted that BMO Capital Markets had recently forecast an equity market return of 6.5 to 7.2 per cent, with a market equity risk premium of 3.5 to 4.2 per cent and, that the mid-point of estimates from Fiduciary Trust Company of Canada for the equity market return and market equity risk premium (relative to yields on 10-year Government of Canada bonds) were eight per cent and five per cent, respectively. The UCA also submitted that, in Mercer's 2011 Fearless Forecast survey of Canadian and global institutional investment managers, the median expected return for the TSX Composite is 8.5 per cent. The 2011 Towers Watson survey results, which show participants' expectations for the TSX Composite Index return in the short, medium and long-term, indicated that the median or 50th percentile short-term expectation for 2011 was eight per cent, with the median medium and long-term expectations below eight per cent.[95]

130. Drs. Kryzanowski and Roberts and Dr. Booth also referred to, and summarized, the results of surveys conducted by Drs. Fernandez and del Campo of forward-looking estimates of the market equity risk premium and total equity market returns by academics, financial professionals, and corporate finance executives. The UCA submitted that, as these surveys show, the mean and median forward-looking market equity risk premium estimates are in the low five per cent range, with academics generally providing the highest estimates. The estimates declined from 2009 to 2010.[96] The Commission notes that using a risk-free rate of 3.4 to 3.8 per cent, this would imply market returns in the range of eight to nine per cent.

131. Drs. Kryzanowski and Roberts also described surveys of U.S. chief financial officers conducted by Drs. Graham and Harvey concerning expected returns on the S&P 500. They summarized the results of a series of such surveys in their Schedule 2.9.3.2a, which shows an average expected overall market return of less than 7 per cent for the most recent periods and expected market equity risk premiums for those periods of 3 per cent or less.[97]

95 Exhibit 210, UCA argument, paragraph 122.
96 Exhibit 210, UCA argument, paragraph 123.
97 Exhibit 81.02, prepared testimony of Drs. Kryzanowski and Roberts, Schedule 2.9.3.2a.

132. The Utilities submitted that survey results do not provide a reliable basis for estimating the cost of capital because they do not provide supporting quantitative analysis and do not indicate whether the results are in the nature of a geometric or arithmetic average. The Utilities also stated that corporations making investment decisions were using hurdle rates of 14 per cent at a time when the 10-year Treasury yield was four per cent.[98]

133. The Commission finds that the evidence provided by interveners suggests that pension, investment manager and economist return expectations for the market are in the eight per cent range.

### 3.10 Impact of growth on required ROE

134. The UCA submitted that, in principle, it was not persuaded that the potential for growth should be a factor in determining an appropriate ROE. If the allowed ROE is set equal to the risk-adjusted cost of capital for utility investments, investors should be indifferent as between utility investments and the alternatives available in the market. If it is established that the potential for growth is a highly attractive attribute for utility stocks, this suggests that the allowed ROEs are generous. The more enthusiastic utilities and utility investors are about potential growth, the stronger the implication that allowed returns exceed the true cost of equity.[99]

135. The Utilities submitted that growth is attractive and that it could result in a reduction of existing price-to-book ratios over time, but that growth does not suggest a lower ROE should be approved. The Utilities submitted that extremely large growth can result in increased financial risk.[100]

136. The Commission acknowledges that investors should, in theory, be indifferent to growth if growth is only expected to provide a risk-adjusted return readily available elsewhere in the market. The Commission notes that growth in utilities requires additional earnings to be retained rather than paid out as dividends or may require the injection of equity for which the investor will only receive the allowed ROE. In general, the intervener experts appeared to view their ROE recommendations as being somewhat generous. Ms. McShane submitted the ROE should be above the bare bones cost.

137. In addition, the Commission notes the evidence of Mr. Engen who submitted that growth in earnings per share (EPS) is what is important to investors[101] and that EPS accretion is widely used and accepted by the investment community as an important rationale in justifying acquisitions. He submitted that whether, and under what circumstances, financial theory would or would not support the view that EPS accretion increases value is not relevant to whether the EPS accretion is used in practice to support acquisitions.[102]

138. In the Commission's view, it is reasonable to conclude that investors value growth only if the expected growth provides the necessary return. Investors might accept a somewhat lower expected and awarded ROE for a high-growth utility, as compared to a low-growth utility, but only if they expect that the utility will be able to earn in excess of its awarded ROE.

98 Exhibit 220, Utilities reply argument, paragraph 69.
99 Exhibit 210, UCA argument, paragraph 128.
100 Exhibit 209, Utility argument, paragraphs 118-121.
101 Exhibit 86.01, evidence of Aaron M. Engen, page 10, lines 18 and 19.
102 Exhibit 152.01, rebuttal evidence of Aaron M. Engen, paragraph A24.

## 3.11 The

148. The evidence provided by interveners suggests that pension, investment manager and economist return expectations for the market are in the eight per cent range.

149. Having considered and weighed all of the evidence and assessed it in the context of the lingering credit market volatility, and recognizing that there has been a reduction in the risk free rate of some 60 basis since 2009 by the close of the record of this proceeding, the Commission finds that some reduction in the ROE awarded in Decision 2009-216 is warranted. Accepting that some of the reduction in the risk free rate may be offset by an increase in the market equity risk premium, the Commission considers that a generic ROE of 8.75 per cent is reasonable for 2011.

## 4 Return to the formula adjustment in 2012

150. Having determined the generic rate of return on equity for 2011, the Commission must consider how that rate of return will be adjusted in future years. One of the principal purposes of this proceeding has been to consider whether the annual adjustment formula approach discontinued in 2009 should be reinstated and if so, what type of formula for annual adjustments to ROE should be adopted by the Commission.

151. In Decision 2004-052, the Commission's predecessor, the Alberta Energy and Utilities Board (EUB or Board) adopted the annual adjustment formula for setting the generic ROE based on 75 per cent of the change in long Canada bond yields:[105]

$$ROE_{New} = \text{Initial ROE} + 75\% \times (\text{Change in forecast 30-year GOC bond yield})$$

152. This formula was discontinued in Decision 2009-216, because of the economic crisis conditions observed at the time of the 2009 GCOC proceeding. Specifically, the Commission concluded that the historical relationships upon which the formula was based had not yet been re-established in the aftermath of the financial crisis.[106]

153. In this proceeding, the Utilities recommended that the Commission not adopt an automatic adjustment formula at this time for two reasons. First, the Commission's performance-based regulation (PBR) initiative for distribution utilities could change the risk profile of the distribution utilities and may require the re-evaluation of the fair ROE. Second, as outlined in Section 3.2 above, the Utilities argued that there remained considerable risk in the global economy and capital markets.[107]

154. However, the Utilities submitted that, if the Commission determined that an automatic adjustment mechanism is warranted for 2012, the formula adopted by the OEB in its Report EB-2009-0084 should be used. The OEB formula is as follows:

$$\begin{aligned} ROE_{New} = \text{Initial ROE} &+ 50\% \times (\text{Change in forecast 30-year GOC bond yield}) + \\ &+ 50\% \times (\text{Change in utility bond yield spread}) \end{aligned}$$

155. The Utilities indicated that Ms. McShane's independent analysis supported the factors and weightings used in this formula, based on the historical relationships among the utility cost of equity, long-term government bond yields and corporate bond yield spreads.

[105] Decision 2004-052, page 32.
[106] Decision 2009-216, paragraphs 418-420.
[107] Exhibit 209, Utilities argument, paragraphs 122.

156. The UCA witnesses, Drs. Kryzanowski and Roberts, agreed that the formula adopted by the OEB reflects an appropriate adjustment structure. The UCA's position was that the Commission should return to a formula approach to setting allowed ROEs on a generic basis for the Alberta utilities because of the practical advantages resulting from regulatory efficiency. The UCA submitted that a properly designed ROE formula provides reasonably accurate estimates of the true cost of equity over a reasonable period.

157. Based on their opinion that credit markets had normalized, Drs. Kryzanowski and Roberts did not share the Utilities' view that the return to a formula would not be beneficial at this time. Furthermore, the UCA witnesses pointed out that introducing a utility bond spread component will mitigate any remaining concerns as to the financial market volatility.[108] With respect to the Utilities' concerns related to the ongoing PBR proceeding, the UCA expressed the opinion that the PBR may not involve any material changes in business risk. Additionally, the UCA indicated that one would expect changes in business risk to be addressed through capital structure adjustments rather than ROE adjustments, in accordance with past practice in Alberta.[109]

158. Dr. Booth, testifying on behalf of CAPP, proposed a modified formula that reflects 75 per cent of the change in the Government of Canada long bond yield and 50 per cent of the change in utility bond spreads:

$$\begin{aligned} ROE_{New} = {} & \text{Initial ROE} + 75\% \times (\text{Change in forecast 30-year GOC bond yield}) + \\ & + 50\% \times (\text{Change in utility bond yield spread}) \end{aligned}$$

159. Dr. Booth explained that the 75 per cent adjustment factor is consistent with the formula that the Commission and its predecessor used between 2004 and 2009, and is supported by his analysis of market and utility risk premia.[110] By contrast, CAPP submitted that the formula proposed by Ms. McShane, with the 50 per cent adjustment factor for the Government of Canada long bond yield, would imply ROEs higher than those determined by regulators in that time period, including this Commission's predecessor.

160. CAPP also pointed out that the Quebec Régie de l'Energie accepted Dr. Booth's modified formula in a recent Gazifere decision (D2010-147) and will use it beginning in 2012.

161. The CCA indicated that none of the formulae proposed in this proceeding appear to be based on any financial analysis as to their validity and submitted that it prefers the Commission not return to an adjustment formula but periodically set a generic ROE.[111]

## Commission findings

162. In Decision 2009-216, the Commission observed that due to the then-existing credit crisis conditions, the relationships among various market indicators were not stable and decided not to employ an adjustment formula for 2010. As discussed in Section 3.2 above, the evidence in this proceeding demonstrated that, although there has been some improvement in the financial environment, credit markets remain volatile. Referring to the financial community's concerns with the European sovereign debt, Dr. Booth summarized this view as follows:

108 Exhibit 210.02, UCA argument, paragraph 16.
109 Ibid., paragraph 21-22.
110 Exhibit 78.02, evidence of Laurence D. Booth, paragraphs 180-184.
111 Exhibit 211, CCA argument, paragraph 21.

> The fact is that we don't know all of the linkages in the credit default swap market, so that is a palpable nervousness in the bond market. That is something that is highly unusual. It is still there. It is nowhere near as bad as it was three years ago, but it is there, and we do not have a normal market.[112]

163. As the Commission explained in Decision 2009-216, the 2004 formula was developed based on the expectation that the required rate of return for utilities moves in the same direction as the return on 30-year Government of Canada bonds. The Commission found that, during a time of adverse market conditions, this expected relationship between interest rates and the required return on equities does not necessarily hold.[113]

164. All parties to this proceeding preferred a formula that considered both changes in Government bond yields, and changes in utility bond spreads. The Commission agrees that this type of formula will better reflect any fluctuations in financial market conditions and deal with the concerns about a single variable formula. Moreover, as Dr. Booth's explained, such a formula would be counter-cyclical because allowed returns would increase in difficult economic times and decrease in strong economic times, but over the business cycle this will average out.[114]

165. The Commission agrees with the interveners' arguments that a modified formula that accounts for changes in corporate bond spreads partially corrects for the drawbacks of a single-variable formula. Nevertheless, the Commission has considered the evidence of continuing credit market volatility and finds that a return to the formula mechanism for annual adjustments to ROE is not warranted at this time.

166. Accordingly, the Commission will not employ an adjustment formula for 2012. At the same time, as noted in the Decision 2009-216, the Commission is not prepared to preclude a return to some form of formula-based adjustment mechanism in the future, once the capital markets have stabilized and are once again considered reasonably predictable.[115] As such, the Commission is prepared to revisit the re-introduction of an automatic adjustment mechanism once the credit markets are more predictable and the Commission can be confident that the relationships implied in the formula will continue.

167. As explained in Section 3.11 of this decision, the Commission has determined that a fair generic rate of return on equity for Alberta utilities for 2011 is 8.75 per cent. Given the December 8, 2011 issue date of this decision and the fact that the record closed on September 9, 2011, the Commission is mindful of the proximity of this decision date to 2012. Considering the substantial drop in interest rates by the close of the record, the Commission sees no reason to find that the risk free rate of 3.4 to 3.8 per cent that it has accepted as reasonable for 2011 would not also be reasonable for 2012. The Commission does not consider that adjustments to any of its other findings with respect to the establishment of a reasonable ROE for 2011 are warranted for 2012. Accordingly, the Commission concludes that an ROE of 8.75 per cent is fair for both 2011 and 2012.

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112 Transcript, Volume 7, page 911, lines 8 to 13.
113 Decision 2009-216, paragraphs 417 and 418.
114 Exhibit 207.02, paragraph 97.
115 Decision 2009-216, paragraphs 420-422.

168. In addition, the Commission is setting the allowed ROE for 2013 at 8.75 per cent on an interim basis. The Commission will initiate a proceeding in due course to establish a final allowed ROE for 2013 and to revisit the matter of a return to a formula for setting the allowed ROE on a go forward basis. The Commission considers that establishing an allowed ROE for 2012 and setting an interim ROE for 2013 will provide for a more supportive, and predictable regulatory environment.

# 5 Capital structure matters

## 5.1 Introduction

169. To satisfy the fair return standard, the Commission is required to determine a capital structure (equity ratio) for each of the utilities that are the subject of this proceeding. In this decision, the Commission has established a generic ROE of 8.75 per cent which will be applied uniformly to all of the utilities. Consistent with the approach taken in the previous GCOC decisions, the Commission will account for the differences in risk among the individual utilities by adjusting their capital structures.

170. As the Commission noted in Decision 2009-216, in general, the return required by investors on debt is lower than the return required on equity. This is because debt holders have priority over equity holders in the distribution of earnings from operations and, in the event of bankruptcy, in the disposition of the assets of the firm. As the proportion of debt in the capital increases, a greater portion of the earnings from operations of the firm are required to cover the increased interest costs on debt. Therefore, as the proportion of debt rises, both debt and equity investors will perceive an increase in risk: debt holders will be concerned that the debt obligations of the firm may not be met, and equity investors will be concerned that there will be insufficient earnings from operations to both cover the debt obligations of the firm and pay them their expected return.

171. This risk is usually assessed by various interest coverage calculations that measure the ability of the firm to pay its debt obligations. Bond rating agencies, such as Standard & Poor's (S&P) and DBRS Limited (DBRS) assess the risk of individual firms on the basis of various interest coverage metrics and an overall assessment of the risk that the firm will not be able to cover its debt obligations.

172. In this decision, the Commission will establish the capital structure for each utility that, in the Commission's judgment, would allow a stand-alone utility to maintain a credit rating in the A range, subject to company-specific circumstances. To do so, the Commission will first consider the impact of changes in the credit environment since the time of the 2009 GCOC proceeding. The Commission will then analyze the equity ratios that are required to attain the minimum credit metrics that were identified in Decision 2009-216. Finally, the Commission will turn to an assessment of each individual utility to determine whether specific adjustments to each company's equity ratio are warranted.

173. The following table (grouped by sector) compares the equity ratios that were approved by the Commission in Decision 2009-216 with the equity ratios recommended by the applicants and interveners in this proceeding.

Table 7. Recommended vs. currently approved equity ratios

| | Last approved[116] (%) | Recommended by the Utilities[117] (%) | Recommended by the UCA[118] (%) | Recommended by the CCA[119] (%) | Recommended by CAPP[120] (%) |
|---|---|---|---|---|---|
| **Electric and Gas Transmission** | | | | | |
| ATCO Electric TFO | 36 | 38 | 34 | 36 | |
| AltaLink | 36 | 38 | 36 | 36 | |
| ENMAX TFO | 37 | 39 | 30 | 36 | |
| EPCOR TFO | 37 | 39 | 33 | 36 | |
| ATCO Pipelines | 45 | 47 (for 2011)<br>44 (for 2012)[121] | 42 (for 2011)<br>30 (for 2012) | 42 (for 2011)<br>40 (for 2012) | 35 (for 2012) |
| **Electric and Gas Distribution** | | | | | |
| ATCO Electric DISCO | 39 | 41 | 35 | 37 | |
| ENMAX DISCO | 41 | 43 | 35 | 39 | |
| EPCOR DISCO | 41 | 43 | 35 | 39 | |
| ATCO Gas | 39 | 41 | 34 | 37 | |
| FortisAlberta | 41 | 43 | 35 | 39 | |
| AltaGas | 43 | 45 | 40 | 41 | |

## 5.2 Credit environment

174. Much of the ROE and capital structure discussion in this proceeding centered on whether markets have returned to normal and whether the credit crisis discussed in Decision 2009-216 has passed. As discussed in more detail in Section 3.2 above, the Utilities cautioned that, while markets improved since the peak of the crisis, they have not returned to normal conditions. The interveners argued that economic parameters relevant to the cost of capital determinations have improved significantly and could be considered normal.

175. The Utilities submitted that, due to the persistence of significant downside risks to Canadian and global capital markets and economies, the two per cent across-the-board increase in common equity ratios approved in Decision 2009-216 was still relevant. Furthermore, Ms. McShane, who appeared on behalf of the Utilities, expressed her opinion that rating agencies do not view this across-the-board increase as temporary and, therefore, any reduction to equity ratios in the current proceeding could send negative signals to the market. As such, Ms. McShane used the capital structures approved in Decision 2009-216 as the point of departure in developing the Utilities' generic capital structure recommendations.[122]

176. In contrast, the UCA witnesses, Drs. Kryzanowski and Roberts, recommended that the Commission reverse the two percentage point equity ratio increase it awarded to all of the utilities in the 2009 GCOC. Their reasoning was that the additional two per cent was primarily awarded in order to account for the effects of the credit crisis, and because the credit crisis is

116 Decision 2009-216, Table 17, page 107.
117 Exhibit 209, Utilities argument, paragraph 129 (unless noted otherwise).
118 Exhibit 210.02, UCA argument, paragraph 215.
119 Exhibit 211, CCA argument, paragraph 58 (corrected as per Exhibit 213).
120 Exhibit 207.02, CAPP argument, paragraph 97.
121 Exhibit 208, ATCO Pipelines argument, paragraph 1.
122 Exhibit 209, Utilities argument, paragraphs 137-138.

over, there is no need to continue providing the Utilities with that additional financial flexibility.[123]

177. The UCA witnesses did not agree with Ms. McShane's position that the two per cent increase awarded in Decision 2009-216 was permanent and submitted that such an approach advocates the need for a permanent increase in shareholder returns, not because of what the actual capital market conditions were at the time of the decision, but because of the risk that problems similar to the financial crisis might arise in the future. Drs. Kryzanowski and Roberts submitted that the credit crisis was a rare event occurring approximately once in 75 years, and as such, it would not be fair to provide a permanent bonus to utility shareholders in order to insulate them against the potential effects of a near-catastrophic event that may not happen again for decades.[124]

178. The CCA supported the removal of the across-the-board two per cent increase in equity ratios awarded in the 2009 GCOC decision as proposed by the UCA, with the exception of the TFOs and ATCO Pipelines as further discussed below.[125] CAPP did not recommend any equity ratios other than for ATCO Pipelines, but did note that the financial market situation had stabilized and the need for any adjustment on this account was significantly reduced from the time of the 2009 GCOC decision when the Commission remained concerned about an uncertain future.[126]

#### Commission findings

179. As the Commission observed in Section 3.2 above, by the time of the 2011 GCOC hearing, economic parameters relevant to cost of capital determinations had improved significantly since the 2009 GCOC proceeding. Therefore, while cognizant of the lingering uncertainty in the debt markets related to concerns over sovereign debt in Europe and the U.S., the Commission agrees with Dr. Booth's opinion that the need for an adjustment to account for the financial crisis is reduced from the time of the 2009 GCOC decision.

180. However, as the Utilities pointed out, the credit crisis was only one of several factors that led to the two percentage point increase in equity thickness awarded in Decision 2009-216. Therefore, the Commission does not accept the UCA's proposal to reverse the two per cent equity ratio increase, solely because the credit crisis concerns have somewhat abated.

## 5.3 Credit metric considerations

### 5.3.1 Financial ratios, capital structure and actual credit ratings

181. Credit ratings measure the credit-worthiness of a firm. A higher credit rating signals higher confidence in the firm's ability to meet its interest payments. This, in turn, allows the company to borrow at a lower interest rate. Utilities usually seek to maintain a credit rating in the A range.

182. As discussed in Section 5.1Error! Reference source not found. above, credit metrics (financial ratios) are an important part of bond rating agencies' considerations when assessing

123 Exhibit 210.02, UCA argument, paragraph 225.
124 Ibid., paragraphs 228-321.
125 Exhibit 211, CCA argument, paragraph 52.
126 Exhibit 207.02, CAPP argument, paragraph 90.

the risk of any particular company and assigning a credit rating. As noted in the 2009 GCOC decision, there are three principal credit metrics:

- EBIT coverage (interest coverage ratio), which is the company's earnings measured before deducting interest and taxes divided by total interest costs
- funds for operation (FFO)/debt, which is the company's funds from operations (net income plus depreciation and the increase in future income taxes) as a percentage of total debt
- FFO coverage, which is the company's funds from operations plus interest divided by total interest costs

183. The Commission observed in Decision 2009-216 that a number of Canadian utility companies finance their debt requirements directly in the debt market independently of any affiliated companies, thereby making it possible to directly see the equity ratios and credit metrics that are associated with stand-alone regulated utilities that have credit ratings in the A range. Consequently, the Commission examined the credit ratings of those companies for which credit rating reports were available on the record, in order to gain some insight into the credit metrics required to achieve an investment grade credit rating for a stand-alone utility.

184. In Decision 2009-216, the Commission observed the following minimum credit metrics associated with an A-range credit rating:[127]

- EBIT coverage of 2.0 times
- FFO coverage of 3.0 times
- FFO/debt ratio of 11.1 to 14.3%

185. The sample group of utilities that were examined in arriving at these observed credit metrics were exclusively Alberta utilities: AltaLink L.P., AltaLink Investments L.P., Fortis Inc., FortisAlberta and CU Inc., the parent of the ATCO group of utilities.

186. Additionally, after examining the actual credit ratings achieved by Canadian regulated utilities and the equity ratios associated with these credit ratings, the Commission observed that the actual equity ratios of the companies with a credit rating of A- or better ranged from 32.9 to 44.1 per cent, with a mid point of 38.5 per cent.[128]

187. The sample group of utilities that were examined in arriving at this observed range of equity ratios were the same Alberta utilities that were examined with respect to credit metrics (set out above) plus Newfoundland Power Inc.

188. In this proceeding, the Utilities noted that the importance of debt ratings in the A category for the Alberta utilities was reviewed in detail in the 2009 GCOC process, when the Commission established a capital structure that would allow a stand-alone utility to maintain a credit rating in the A range. In that regard, the Utilities submitted that there have been no fundamental changes in the capital markets or utility requirements for access to debt capital that would warrant revisiting that conclusion.[129]

[127] Decision 2009-216, Table 12 and paragraphs 348, 354 and 356.
[128] Ibid., paragraph 359.
[129] Exhibit 209, Utilities argument, paragraphs 135.

189. The Utilities' position on the acceptability of the minimum credit metrics set out in Decision 2009-216 was not explicitly stated in argument, but appeared to be implicitly accepted. In particular, Ms. McShane testified that she used the minimum credit metrics observed in Decision 2009-216 as a point of departure.[130]

190. In her evidence, Ms. McShane also provided a review of changes in the equity ratios adopted for the Canadian peers of the Alberta utilities. Specifically, Ms. McShane indicated that, since the close of the oral portion of the last GCOC proceeding, there have been a number of increases in equity ratios approved by regulators. Based on her observation that the average regulated common equity ratio for utilities outside Alberta was 40 per cent, Ms. McShane considered this number to be a reasonable benchmark equity ratio for an average risk Alberta utility.[131]

191. The UCA submitted that it accepted the minimum credit metrics set out in Decision 2009-216 as reasonable guidelines, but emphasized Drs. Kryzanowski and Roberts' view that credit ratings do not follow a formula and depend on numerous qualitative factors and an examination by the rating agencies of numerous aspects of the businesses for which the ratings are prepared. The UCA witnesses also noted that their recommended equity ratios were generally consistent with the minimum equity ratios identified by the Commission.[132]

192. The CCA submitted that it did not accept benchmarking to the awards of other regulators as a tool for determining capital structure, as this method leads to a circularity problem. The CCA noted it accepts regulatory benchmarking only for information purposes, and only for comparison of methods, not for the actual awards.[133]

### Commission findings

193. As discussed in Decision 2009-216, utilities usually seek to maintain their credit rating in the A range to avoid paying higher interest rates on debt typically associated with lower rating categories. Furthermore, as the Commission observed recently in Decision 2011-453[134] dealing with AltaLink's 2011-2012 GTA, a lower credit rating may limit a company's access to capital markets. In particular, the Commission noted that, as a BBB category issuer, a utility may face more significant challenges in accessing debt markets, particularly at a time of adverse market conditions.[135]

194. Therefore, the Commission reaffirms its finding that it is important to target the debt ratings for the Alberta utilities in the A category, as established in the 2009 GCOC process. The Commission agrees with the parties to this proceeding that minimum credit metrics associated with an A-range credit rating, which were observed in Decision 2009-216, can be accepted as reasonable guidelines for the purposes of this proceeding.

195. With respect to Ms. McShane's recommended benchmark equity ratio of 40 per cent, the Commission agrees with the CCA that equity ratios awarded by other regulators are of interest

130 Transcript, Volume 2, page 242, lines 8 to 11.
131 Exhibit 86.01, Kathleen McShane Opinion, pages 30-32.
132 Exhibit 210.02, UCA argument, paragraphs 156-160.
133 Exhibit 211, CCA argument, paragraphs 50 and 51.
134 Decision 2011-453: AltaLink Management Ltd. 2011-2013 General Tariff Application, Application No. 1606895, Proceeding ID No. 1021, November 18, 2011.
135 Decision 2011-453, paragraph 798.

but are far from determinative of the capital structure this Commission should award. Furthermore, in Decision 2009-216, the Commission observed the actual equity ratios of the utilities in the A range rating category. Ms. McShane did not specify whether her analysis of capital ratios awarded by other regulators was limited only to the A-rated utilities.

### 5.3.2 Equity ratios associated with minimum credit metrics

196. In Decision 2009-216, the Commission provided a sensitivity analysis of the three key credit metrics to changes in the equity ratio. Assuming an embedded cost of debt of 6.5 per cent, an ROE of 8.75 per cent (the 2009 placeholder level), an income tax rate of 29 per cent, and assuming the annual depreciation expense as a percentage of invested capital equal to the utility average of six per cent, the Commission calculated the following minimum equity ratios required to achieve the observed minimum credit metrics:[136]

- The minimum equity ratio to achieve a 2.0 EBIT coverage ratio was 34 per cent.
- Minimum equity ratios in the range of 30 to 36 per cent would achieve FFO/debt percentages of 11.1-14.3.
- A minimum equity ratio of 33 per cent was required to achieve an FFO coverage ratio of at least 3.0.

197. Ms. McShane proposed to update the Commission's analysis in Decision 2009-216 by making three adjustments. The first was to assume a reduction in average debt costs for the average utility. The second was to include an assumed five per cent construction work in progress (CWIP) in the credit metric calculation for the hypothetical average utility. The third involved recalculating the hypothetical credit metrics using the lower tax rates that apply in 2012.

198. With respect to the first adjustment, Ms. McShane noted that a review of the 2009 embedded debt costs provided by the Alberta utilities in their Rule 005[137] filing requirements indicated that there has been a marginal decline since 2007 (less than 10 basis points). Therefore, Ms. McShane proposed to use a 6.4 per cent average embedded cost of debt as compared to the 6.5 per cent rate used by the Commission in Decision 2009-216, which would have the effect of improving credit metrics and decreasing the necessary equity ratio.[138]

199. Next, Ms. McShane indicated that even a relatively small percentage of CWIP has a measurable impact on EBIT interest coverage ratios. Based on her observation that the median of CWIP as a per cent of total regulated assets in 2009 for the Alberta utilities was around five per cent, Ms. McShane proposed to include this amount of CWIP in the calculations of equity ratios required to achieve the minimum EBIT coverage ratios observed by the Commission.

200. With respect to the impact of income taxes, Ms. McShane indicated that, in 2012, the combined provincial and federal corporate income tax rate will be 25 per cent, compared to the 29 per cent used in the analysis set out in Decision 2009-216. Furthermore, the Utilities' witness indicated that the median actual effective income tax rate for the taxable Alberta Utilities in 2009 (excluding AltaLink) was less than half the statutory combined rate.[139] As such, Ms. McShane

[136] Decision 2009-216, paragraphs 352, 354 and 356.
[137] AUC Rule 005: *Annual Reporting Requirements of Financial and Operational Results* (Rule 005).
[138] Exhibit 86.01, Kathleen McShane Opinion, page 25, lines 638-646.
[139] Ibid., page 27, lines 674-683.

proposed to use the 12.5 per cent tax rate in equity ratio calculations, which represents 50 per cent of the 2012 statutory tax combined rate of 25 per cent.

201. Incorporating these recommended assumptions regarding the embedded cost of debt, effective tax rate and presence of CWIP,[140] the Utilities provided updated versions of the Commission's analysis of equity ratios in Decision 2009-216 as follows:

**Table 8. Credit metrics compared to equity ratios – McShane's evidence**

| | EBIT coverage | | FFO/Debt | | FFO coverage | |
|---|---|---|---|---|---|---|
| Equity Ratio | Table 13 in Decision 2009-216 | Updated and expanded assumptions | Table 14 in Decision 2009-216 | Updated and expanded assumptions | Table 15 in Decision 2009-216 | Updated and expanded assumptions |
| 30% | 1.8 | 1.6 | 12.32 | 11.71 | 2.90 | 2.78 |
| 31% | 1.9 | 1.6 | 12.63 | 12.00 | 2.94 | 2.82 |
| 32% | 1.9 | 1.6 | 12.94 | 12.29 | 2.99 | 2.87 |
| 33% | 1.9 | 1.7 | 13.26 | 12.60 | **3.04** | 2.92 |
| 34% | 2.0 | 1.7 | 13.60 | 12.92 | 3.09 | 2.97 |
| 35% | **2.0** | 1.7 | 13.94 | 13.25 | 3.14 | **3.02** |
| 36% | 2.1 | 1.8 | **14.30** | 13.58 | 3.20 | 3.07 |
| 37% | 2.1 | 1.8 | 14.66 | 13.93 | 3.26 | 3.13 |
| 38% | 2.2 | 1.9 | 15.04 | **14.29** | 3.31 | 3.18 |
| 39% | 2.2 | 1.9 | 15.43 | 14.66 | 3.37 | 3.24 |
| 40% | 2.3 | 1.9 | 15.83 | 15.04 | 3.44 | 3.30 |
| 41% | 2.3 | **2.0** | 16.25 | 15.44 | 3.50 | 3.36 |
| 42% | 2.4 | 2.0 | 16.68 | 15.85 | 3.57 | 3.43 |
| 43% | 2.4 | 2.1 | 17.13 | 16.27 | 3.63 | 3.49 |
| 44% | 2.5 | 2.1 | 17.59 | 16.71 | 3.71 | 3.56 |
| 45% | 2.6 | 2.2 | 18.07 | 17.16 | 3.78 | 3.63 |
| 46% | 2.6 | 2.2 | | | | |
| 47% | 2.7 | 2.3 | | | | |

Source: Exhibit 209, Utilities argument, Attachment 2.

202. Based on her evaluation of the net effect of the three adjustments on credit metrics (as presented in Table 8 above), Ms. McShane concluded that an increase in the common equity ratios of no less than two percentage points was warranted. The highlighted examples in the table illustrate that a minimum two percentage point equity ratio increase is necessary to restore the credit metrics to the levels that applied under the 2009 calculations, given Ms. McShane's assumptions.

203. The UCA took issue with the Utilities' inclusion of CWIP and a lower tax rate in the credit metrics calculation. The UCA submitted that, in Decision 2009-216, the Commission implicitly took these factors into account and the resulting equity ratios were well received by the rating agencies. In the UCA's opinion, the relevant facts or circumstances have not changed

[140] Utilities' assumptions: embedded cost of debt of 6.4 per cent, ROE of 8.75 per cent, effective tax rate of 12.5 per cent (50 per cent of 2012 statutory tax rate), 5.0 per cent CWIP as percentage of regulated assets, depreciation rate of 6.0 per cent.

since 2009, and as such, Ms. McShane's analysis was simply an arbitrary re-definition of the Commission's model.[141]

204. The UCA also noted that, in the case of the two transmission utilities that have the highest levels of CWIP – ATCO Electric and AltaLink, the Commission addressed this issue in other ways in their respective GTAs.[142]

205. With respect to Ms. McShane's adjustment related to lower tax rates, the UCA observed that any changes in tax rates affects only the EBIT coverage credit metric, since the FFO/debt and FFO interest coverage metrics are after tax measures. The UCA also submitted that, under a flow-through tax regime, changes in either statutory or effective tax rates do not have any material impact on bondholders or the creditworthiness of the utilities, because the funds collected for taxes on a forecast basis are earmarked for payment to the tax authorities and so are not available to pay creditors.[143]

206. The UCA conceded that lower tax rates reduce the EBIT interest coverage ratio but argued that credit rating agencies do not take the "rigidly rule-based formulaic approach" to understanding credit ratings and credit metrics, and arrive at a balanced assessment of creditworthiness that takes into account all of the moving parts that affect the interests of bond investors.[144] As a result of these considerations, the UCA argued there was no need to update the Commission's credit metric analysis tables in Decision 2009-216.

207. The CCA agreed with the UCA's analysis on CWIP and effective income taxes. Specifically, the CCA argued that there should be no adjustment for income tax rates because deferred income tax must ultimately be paid and financial analysts have not identified deferred income taxes as a risk. In addition, the CCA observed that the effective income tax rate varies greatly from utility to utility and, therefore, any required adjustments should be made on a utility-specific, rather than generic, basis.[145]

208. Similarly, the CCA objected to the across-the-board adjustment for CWIP. The CCA expressed its opinion that a large amount of CWIP is currently a problem for the TFOs but not for all the utilities. The CCA submitted that there is little risk from CWIP and that no adjustment to ROE was necessary for any amount of CWIP.[146]

209. In reply argument, the Utilities submitted that the absence of downgrades does not constitute an appropriate basis for evaluating the reasonableness of Ms. McShane's recommendations and argued that it was necessary to include CWIP amounts in the equity ratio analysis so that the credit metrics identified by the Commission as minimums would be achievable.

210. The Utilities also took issue with the UCA's argument that the income tax allowance is earmarked for payment to the income tax authorities and is not available for payment to creditors. The Utilities submitted that this view does not comport to the manner in which the debt rating agencies evaluate a company's ability to meet its debt obligations. The Utilities explained

141 Exhibit 210.02, UCA Argument, paragraphs 167 and 173.
142 Ibid., paragraph 170.
143 Ibid., paragraphs 178-179.
144 Ibid., paragraphs 182-184.
145 Exhibit 211, CCA argument, paragraphs 37-38.
146 Ibid., paragraph 40.

that, since interest expense is tax-deductible, income taxes payable are partly a function of how much interest is paid and therefore, it is logical that the debt rating agencies would consider the pre-tax funds that a company has available to cover its debt obligations.[147]

### Commission findings

211. In Decision 2009-216, the Commission presented its analysis of equity ratios required to achieve the minimum credit metrics considered to be associated with credit ratings in the A range. The Commission expressly stated that this analysis did not include the consideration of CWIP or cash flows created by positive or negative differences between tax collected and tax paid.[148]

212. In this proceeding, the Utilities pointed out that even a small percentage of CWIP has a measurable impact on credit metrics. As noted in Decision 2009-216, the Commission agrees that the presence of CWIP lowers the credit metrics.[149] In fact, recognizing this reality, the Commission, through its issues list, invited parties to update the credit metric tables with relevant assumptions as to the typical level of CWIP for the Alberta utilities.

213. As discussed further in this section, the Commission agrees with the UCA and the CCA that the adjustment for CWIP is not necessary for ATCO Electric TFO and AltaLink, given that this matter was recently addressed in their respective GTAs. However, the Commission is not persuaded by the interveners' arguments that CWIP should not be considered in the credit metric calculations for other Alberta utilities.

214. Specifically, the UCA argued that updating the Commission's tables with typical amounts of CWIP and lower income taxes advocates a formulaic approach to credit metrics. The Commission accepts the UCA's point that rating agencies supplement their analysis of credit metrics with a number of other considerations to arrive at a balanced assessment of a company's creditworthiness. As discussed in Section 5.6 below, the Commission's determination on the matter of capital structure is not limited to credit metric analysis and includes a number of factors such as the current credit environment and the ranking of the utility segments based on business risk.

215. The UCA also argued that no adjustment for a typical level of CWIP and lower income taxes is necessary, since the credit rating agencies appeared to be satisfied with the equity ratios approved in Decision 2009-216, as evidenced by the fact that no utilities have been downgraded since 2009. However, the Commission observes that, due to a number of factors, including the impact of the financial crisis and large capital additions (where applicable), the equity ratios approved in 2009 exceeded the minimum levels indicated by the credit metric analysis in that decision by at least two percentage points.[150] Accordingly, the Commission considers that the favourable reaction of the rating agencies may be attributed to the fact that the last approved equity ratios were sufficient to account for typical amounts of CWIP, not the fact that no adjustment for CWIP was necessary.

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147 Exhibit 220.02, Utilities reply argument, paragraph 94.

148 Decision 2009-216, footnote 326 on page 94.

149 Ibid., footnotes 323 and 325.

150 In paragraph 357 of Decision 2009-216, the Commission observed that for an average Alberta utility, the equity ratio associated with the minimum credit metrics would be approximately 34 per cent (34 per cent based on the EBIT analysis, 33 per cent based on the FFO coverage analysis and 30 to 36 per cent based on the FFO/Debt analysis). Table 17 of Decision 2009-216 shows that the minimum equity ratio awarded was 36 per cent.

216. Regarding the CCA's argument that there is little risk from CWIP and that no adjustment to ROE is necessary for any amount of CWIP, the Commission reiterates that the adjustment to the credit metric calculations in regard to CWIP that was solicited through the issues list was not related to the risk of recovering CWIP balances. Rather, the issue was that CWIP mathematically lowers the credit metrics. The CCA did not address this point.

217. Consequently, the Commission is not persuaded by the interveners' arguments that CWIP should not be considered in the credit metric calculations for the Alberta utilities. The Commission has considered the evidence of Ms. McShane that the median of CWIP as a percentage of total regulated assets in 2009 for the Alberta utilities was over five per cent, and finds this number to be a reasonable estimate. The Commission has reflected this level of CWIP in its updated analysis on credit metrics and associated equity ratios, presented in Table 9 below.

218. The Commission also acknowledges the Utilities' evidence that, in 2012, the combined provincial and federal statutory income tax rate will be 25 per cent, as compared to the 29 per cent used in Decision 2009-216. The Commission agrees with Ms. McShane that the income tax rate should be updated in the analysis.

219. In disputing the relevance of lower income tax rates, the UCA submitted that income taxes collected are ear-marked for payment to the tax authorities and so are not available to pay creditors. However, in the event that unforeseen expenses cause profits to decline from the forecast level, the income tax payable would decline and the cash that would otherwise go to taxes would become available to pay interest expenses. Therefore, income taxes collected are in fact partly available to pay creditors in situations where the profit, and therefore the actual amount of income tax payable, is lower than forecast. Additionally, the income tax collected would be fully available to pay interest in the circumstance where profit was zero or negative. Presumably, this is why EBIT (earnings before interest and tax) is important to credit rating agencies and debt investors, rather than simply earnings before interest.

220. However, the Commission does not accept the Utilities' recommendation of using the effective tax rate in the credit metrics analysis. The Commission agrees with the CCA's argument that, because the effective income tax rate varies greatly from utility to utility, any required adjustments should be made on a utility-specific, rather than generic basis. The Commission considers that those utilities that encounter credit rating issues because they are on the flow-through tax method can apply to adopt the future income tax method and thereby collect the full statutory income tax rate. For these reasons, the Commission will use an updated statutory income tax rate of 25 per cent in its analysis below.

221. Using an ROE of 8.75 per cent approved in this decision for 2011 and 2012, and assuming an embedded interest cost of 6.4 per cent, a depreciation rate (as a percentage of invested capital) of six per cent, a tax rate of 25 per cent, and CWIP (as a percentage of rate base) of five per cent, the Commission calculated the key credit metrics and the corresponding equity ratios as follows:

Table 9. Credit metrics compared to equity ratios – Commission analysis

| | EBIT coverage[151] | | FFO/Debt (%) | | FFO coverage | |
|---|---|---|---|---|---|---|
| Equity ratio | Table 13 in Decision 2009-216 | Updated and expanded assumptions | Table 14 in Decision 2009-216 | Updated and expanded assumptions | Table 15 in Decision 2009-216 | Updated and expanded assumptions |
| 30% | 1.8 | 1.7 | 12.32 | 11.73 | 2.90 | 2.79 |
| 31% | 1.9 | 1.7 | 12.63 | 12.03 | 2.94 | 2.83 |
| 32% | 1.9 | 1.8 | 12.94 | 12.32 | 2.99 | 2.88 |
| 33% | 1.9 | 1.8 | 13.26 | 12.63 | **3.04** | 2.93 |
| 34% | **2.0** | 1.8 | 13.60 | 12.95 | 3.09 | 2.98 |
| 35% | 2.0 | 1.9 | 13.94 | 13.28 | 3.14 | **3.03** |
| 36% | 2.1 | 1.9 | **14.30** | 13.62 | 3.20 | 3.08 |
| 37% | 2.1 | **2.0** | 14.66 | 13.96 | 3.26 | 3.13 |
| 38% | 2.2 | 2.0 | 15.04 | **14.32** | 3.31 | 3.19 |
| 39% | 2.2 | 2.1 | 15.43 | 14.7 | 3.37 | 3.25 |
| 40% | 2.3 | 2.1 | 15.83 | 15.08 | 3.44 | 3.31 |
| 41% | 2.3 | 2.2 | 16.25 | 15.48 | 3.50 | 3.37 |
| 42% | 2.4 | 2.2 | 16.68 | 15.89 | 3.57 | 3.43 |
| 43% | 2.4 | 2.3 | 17.13 | 16.31 | 3.63 | 3.5 |
| 44% | 2.5 | 2.3 | 17.59 | 16.75 | 3.71 | 3.57 |
| 45% | 2.6 | 2.4 | 18.07 | 17.21 | 3.78 | 3.64 |

222. Table 9 shows that, given the Commission's assumptions, the minimum equity ratio for Alberta utilities should be 37 per cent based on the EBIT analysis, 30 to 38 per cent based on the FFO/debt analysis and 35 per cent based on the FFO interest coverage analysis. These values show that, as a result of incorporating a typical amount of CWIP and accounting for the lower level of income taxes, the minimum equity levels produced by the credit metric analysis in this decision are somewhat higher than the equity ratios estimated in Tables 13 to 15 of Decision 2009-216.

223. However, as the Commission pointed out earlier in this section, due to a number of factors, including the impacts of the financial crisis and the impact of large capital additions, among others, the equity ratios approved in Decision 2009-216 somewhat exceeded the levels indicated by the credit metric analysis in that decision. In particular, Table 9 above demonstrates that by and large, the currently approved equity ratios of the Alberta utilities meet or exceed the minimum levels determined by the credit metric analysis. In light of these factors, the Commission considers that no across-the-board increase to the currently approved equity ratios for the Alberta utilities is warranted.

151 As discussed in Exhibit 209, Attachment 2 to the Utilities argument, Ms. McShane calculated the EBIT coverage ratios using the S&P methodology, which includes the equity portion of an allowance for funds used during construction (AFUDC) in EBIT component. The Commission used the DBRS methodology, which excludes the equity portion of AFUDC from earnings, resulting in more conservative estimates. However, under the five per cent CWIP assumption, the difference between the two methods is minimal.

## 5.4 Ranking risk by regulated sector

224. In previous GCOC decisions, the Commission ranked the riskiness of the various utility sectors in Alberta based on an analysis of business risk. Business risk affects the perceived uncertainty in future operating earnings and hence determines the capacity for a business to be financed with debt as opposed to equity.

225. In Decision 2009-216, the Commission observed that the electric transmission sector had the least risk. The Commission also found that, in general, the electricity distribution segment was slightly more risky than the electric transmission sector. The Commission agreed that ATCO Gas had a similar level of business risk compared to electric distribution companies, and that AltaGas was more risky than ATCO Gas due to its small size. ATCO Pipelines (transmission) was found to be more risky than ATCO Gas (distribution).[152]

226. In the current proceeding, none of the expert witnesses put forward evidence which would indicate materially changed business risks for the utility sectors since Decision 2009-216, with the exception of ATCO Pipelines in light of the integration with Nova Gas Transmission Ltd. (NGTL).

227. In particular, the Utilities recommended no adjustment, generic or company specific, to capital structures due to the recognition of high levels of contributions in aid of construction (CIAC).[153] The Utilities recommended that compensation for high levels of CIAC occur by way of a management fee, as discussed in Section 6 below. The same argument was put forward by the UCA.[154]

228. As well, the Utilities pointed out that their assessment of the business risks upon which their deemed capital structure recommendations was based did not reflect consideration of the potential of changed risks associated with the implementation of a PBR regime in the near future. The Utilities reasoned that, until the specifics of the form of PBR to which any given utility becomes subject are known, a grounded assessment of changes in risk cannot be made.[155]

229. Furthermore, parties to this proceeding submitted that they were not aware of any adjustments to capital structure that would be required to accommodate growth above the historic trend. The UCA submitted that, to the extent that credit related issues have arisen in the context of mandated transmission builds by Alberta TFOs, those have been, or will be, addressed through utility specific measures like including CWIP in rate base or allowing the collection of future income taxes.[156] The Utilities supported this view.[157]

### Commission findings

230. The Commission has evaluated the expert evidence of witnesses representing interested parties to this proceeding, and agrees that business risks for Alberta utilities have not changed materially since 2009, with the exception of ATCO Pipelines.

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152 Decision 2009-216, paragraphs 370-371.
153 Exhibit 209, Utilities argument, paragraph 154.
154 Exhibit 210.02, UCA argument, paragraph 201.
155 Exhibit 209, Utilities argument, paragraph 155.
156 Exhibit 210.02, UCA argument, paragraph 213.
157 Exhibit 209, Utilities argument, paragraph 156.

231. Consequently, the Commission reaffirms its findings in the 2009 GCOC decision. In particular, as outlined in Decision 2009-216,[158] the Commission finds that the electric transmission sector has the least risk. The electricity distribution segment is slightly more risky than the electric transmission sector. ATCO Gas has a similar level of business risk as compared to electric distribution companies. Due to its small size, AltaGas is more risky than ATCO Gas.

232. The Commission findings with respect to the impact of CIAC are presented in Section 6 of this decision.

### 5.5 Further company-specific considerations

233. The Commission now turns to a consideration of further adjustments to the equity ratios of individual companies based on their specific business risks.

#### 5.5.1 Adjustment for non-taxable status

234. In Decision 2009-216, the Commission affirmed the two percentage point adjustment to common equity ratios for non-taxable utilities, initially approved in Decision 2004-052, on the basis of higher earnings volatility and a negative impact on credit metrics. This adjustment applied to ENMAX and EPCOR utilities and was extended to FortisAlberta, since at the time of the 2009 GCOC decision FAI anticipated being a non-taxable entity until at least 2013.[159]

235. In this proceeding, Ms. McShane noted that, to fully reflect the impact of non-taxability on pre-tax interest coverage ratios, the common equity adjustment would need to be six per cent. Notwithstanding this, the Utilities submitted they supported the findings of the Commission and its predecessor that two percentage points increase is warranted and recommended that this adjustment for non-taxable status continue to apply.[160]

236. Ms. McShane also indicated that, based on FortisAlberta's assessment, it will collect zero income taxes in rates through at least 2016 and, therefore, FortisAlberta remained a de facto non-taxable entity for purposes of this proceeding.[161] As such, in this proceeding, each of the non-taxable utilities (ENMAX and EPCOR as legally non-taxable and FortisAlberta as de facto non-taxable) were seeking a deemed capital structure that continued the treatment established in Decision 2009-216 and Decision 2004-052.

237. The UCA submitted that the additional two per cent equity thickness that has been provided to non-taxable utilities due to their higher earnings volatility was not reasonable or necessary. Specifically, the UCA indicated that the argument regarding increased earnings volatility assumes that any variance in earnings is symmetrical when in fact over-earning is more common. Relying on the data on historical earned ROEs relative to allowed ROEs provided by the Commission in Exhibit 161, the UCA submitted that Alberta utilities are more likely to over-earn their allowed returns than to under-earn, and the benefit of the same amount of over-earning increases with a lower tax rate.[162]

[158] Decision 2009-216, paragraphs 370-371.
[159] Decision 2009-216, paragraphs 383-384.
[160] Exhibit 209, Utilities argument, paragraph 141.
[161] Exhibit 86.01, Kathleen McShane Opinion, page 32, lines 812-817.
[162] Exhibit 210.02, UCA Argument, paragraphs 190-193.

238. During the hearing, Dr. Roberts provided the following explanation on this point:

> Another point I might add is that if a company is not taxable, and it earns, let's say, an extra million dollars, it gets to keep 1 million, whereas if it's taxable, it gets to keep less because part of it has to go to the Canada Revenue Agency.[163]

239. As such, the UCA argued that, in practice, non-taxable status benefits utility shareholders on average by increasing their expected effective ROE relative to the effective ROEs for taxable utilities. In light of this practical benefit, the UCA submitted that there is no need to continue providing shareholders of non-taxable utilities with an even further benefit in the form of a higher allowed equity ratio. The UCA argued that the shareholders of non-taxable utilities are already better off, in terms of their expected return, than shareholders of taxable utilities, and that effect must at least offset whatever minor volatility disadvantage is associated with non-taxable status.[164]

240. In addition, the UCA submitted that, even if the Commission were to maintain the additional two per cent equity for ENMAX and EPCOR, this adjustment should not apply to FortisAlberta which, although temporarily not paying or collecting tax, remains a taxable utility. The UCA submitted that this situation would eventually reverse and FortisAlberta was just as taxable as every other utility.[165]

241. In reply, the Utilities submitted that the document identified as Exhibit 161 contained not just data publicly filed by the Utilities as part of the AUC Rule 005 reports, but adjustments which purport to alter that data. Therefore, the Utilities argued that this document could not form an evidentiary basis for any conclusions proffered by the UCA in its argument, or reached by the Commission in its decision.[166]

### Commission findings

242. The Commission acknowledges that historical ROE data provided in Exhibit 161, along with the publicly available Rule 005 numbers, contain Commission staff calculations. Indeed, recognizing this fact, the Commission invited the Utilities to comment on the numbers provided in Exhibit 161, either through supplemental filings or in argument.[167] The Utilities did not provide any comments on the data in Exhibit 161. Nevertheless, the issue of whether this document can be used as evidence in this proceeding is not germane to the Commission's determination on this matter.

243. In the Commission's view, the UCA's argument that the additional two per cent equity thickness for non-taxable utilities was not necessary fails to account for the fact that the active constraint on the minimum equity ratios is the risk tolerance of debt investors, and not equity investors. Debt investors are concerned by, and could be affected by, the downside risk of an earnings shortfall. In addition, it is equity investors and not debt investors that benefit from upside risk. This is because unlike equity investors, debt holders can not gain more than the

163 Transcript, Volume 6, page 771, lines 21 to 25.
164 Exhibit 210.02, UCA Argument, paragraph 195.
165 Ibid., paragraphs 196-199.
166 Exhibit 220.02, Utilities reply argument, paragraphs 101-104.
167 Transcript, Volume 1, page 15, line 7 to page 16, line 6.

promised interest rate, even if the company performs unusually well. For these reasons, debt investors focus on downside risk, not upside.

244. As such, the Commission reaffirms its findings in Decision 2009-216 that, while income tax exempt status lowers a company's costs, it increases the volatility of earnings and decreases interest coverage ratios, and thereby adds to risk from the debt holder's perspective. Accordingly, the Commission will maintain the addition of the two percentage point increase to the equity ratios of income tax exempt utilities.

245. With respect to FortisAlberta, the Commission notes that it became a de facto non-taxable entity in 2006, and is expected to persist in this status at least through 2016.[168] As such, the Commission considers that this situation cannot be characterized as short run non-taxability. The Commission agrees with the UCA that eventually FortisAlberta will have the same income tax liability as any other taxable entity. However, given the expected duration of FortisAlberta's de facto non-taxable status, the Commission does not share the UCA's view that higher earnings volatility associated with non-taxability will be offset by reduced earnings volatility during the future periods over which this findings this decision will apply.

246. Therefore, in the Commission's view, it is warranted to treat FortisAlberta as a non-taxable entity for the purposes of this proceeding, since it has not collected any income taxes since 2006 and is not expected to until at least 2016. This status would change if FortisAlberta became an income tax paying entity or if the Commission were to change from the flow through method of accounting for income taxes for regulatory purposes to normalized taxes or another similar method in the future.

### 5.5.2 Transmission facility owners and the risk of stranded assets

247. During the hearing, the AESO suggested that ratepayers rather than utility shareholders are at risk for stranded TFO assets.[169] The Commission invited the parties to comment on whether this reality needs to be considered in the risk assessment for the TFOs.

248. The UCA submitted that the AESO's position was likely consistent with the practice in most regulatory jurisdictions and with the expectations of the Utilities. The UCA expressed its opinion that any consideration of where the burden of stranded assets should fall is likely to be fact-specific, and therefore, it would not be appropriate to consider this matter generically in the current proceeding, especially considering that it was not in the original scope.[170]

249. The Utilities expressed similar concerns with the inclusion of this matter as part of this proceeding and pointed out that to date, there have been no examples of stranded assets for either transmission or distribution utilities. The Utilities implied that the AESO's position was consistent with regulatory compact, under which tariffs should provide the opportunity to recover the costs of prudent investments in the system. As such, the Utilities submitted that the business risks of the utilities have not materially changed.[171]

250. The CCA argued for symmetry and reciprocity in the treatment of utility gains and losses. Citing portions of the Stores Block decision, the CCA stated that if gains from the sale of assets

168 Exhibit 86.01, Kathleen McShane opinion, page 32, lines 812-817.
169 Transcript, Volume 3, page 493, line 22 to page 494, line 13.
170 Exhibit 210.02, UCA argument, paragraph 214.
171 Exhibit 209, Utilities argument, paragraphs 158 and 159.

which are not used and useful are to the account of the utility shareholder, losses should also be to the account of the utility shareholder. Therefore, in the hypothetical example on the record, the CCA submitted it did not agree with the position of the AESO.[172]

### Commission findings

251. As set out in Section 7 below dealing with the proposed Rider I concept, the Commission does not share the AESO's view that ratepayers, rather than utility shareholders, are at risk for stranded TFO assets. Specifically, as outlined further in this decision, the Commission considers that any stranded assets should not remain in rate base.

252. The Commission acknowledges that this finding may have certain implications for the quantum of business risks of the transmission utilities. However, as both the Utilities and the AESO[173] pointed out, to date, there have been no examples of stranded assets in Alberta. Furthermore, the Commission considers that any assessment of risk associated with the potential for stranded assets, for the purposes of adjusting capital structure, would be best dealt with on a case-specific determination when the situation arises. Therefore, the Commission will not consider this factor in its risk assessment for TFOs for the purposes of this proceeding.

### 5.5.3 ATCO Pipelin

- supply risk arising from continued decline of the Western Canada Sedimentary basin (WCSB) reserves and especially those within ATCO Pipelines' operating footprint
- construction and financing risk, due to the doubling of ATCO Pipelines' annual capital expenditures

256. As a result, ATCO Pipelines requested a 44 per cent common equity ratio for 2012, which was the mid-point between the 41 per cent common equity ratio recommended by Ms. McShane for gas and electric distribution utilities and the 47 per cent recommended common equity ratio for 2011 for ATCO Pipelines.[178] ATCO Pipelines also argued that the recommended equity ratio of 44 per cent takes into account maintenance of its creditworthiness and financial integrity, assurance that it contributes its fair share to the maintenance of the credit ratings of its parent, and the opportunity to earn an overall return commensurate with investments of comparable risk.[179]

257. Dr. Booth, testifying on behalf of CAPP, pointed out that with integration, ATCO Pipeline's revenue requirement will be paid by NGTL like any other cost of NGTL doing business and ahead of NGTL paying anything to its shareholders. Dr. Booth indicated that this arrangement was very similar to the way in which Alberta electric transmission utilities recover their system costs from the distributors via the Alberta Electric Systems Operator (AESO), and the only real question was the risk of NGTL not being able to make those payments.[180]

258. In that regard, CAPP's witness noted that the combined ATCO Pipelines and NGTL systems sit on top of vast natural gas resources that will provide gas for many decades to come. Based on his analysis of available reports and forecasts, Dr. Booth noted that unconventional supplies will dramatically impact total production from the WCSB, where the growth in Horn River and Montney supply will offset the decline in conventional production.[181] As a result, CAPP argued that with these new supplies, ATCO Pipelines' supply risk has significantly reduced.

259. CAPP also submitted that ATCO Pipelines' competition risk was significantly reduced post integration, since the impact of any successful competition by Alliance Pipelines was no longer borne by ATCO Pipelines by itself, but rather by the combined ATCO Pipelines/NGTL system. Based on the above considerations, CAPP concluded that ATCO Pipelines' risk of not receiving its revenue requirement was no higher than that of Alberta TFOs and recommended that the Commission use a similar common equity ratio of 35 per cent for ATCO Pipelines in 2012.[182]

260. Mr. Marcus, testifying for the UCA, submitted that competitive and market risks will no longer be present for ATCO Pipelines post-integration. Therefore, Mr. Marcus stated that ATCO Pipelines will be similar in risk to an electric transmission utility, which receives fixed payments for services from the AESO.[183] Given this analysis, Drs. Kryzanowski and Roberts recommended a common equity ratio of 42 per cent for 2011, unchanged from their recommendation made in

178 Exhibit 80.01, Kathleen McShane opinion on capital structure for ATCO Pipelines, page 18, A21.
179 Exhibit 208, ATCO Pipelines argument, paragraph 6.
180 Exhibit 78.02, evidence of Laurence D. Booth, paragraph 205.
181 Ibid., paragraph 208; Exhibit 207.02, paragraphs 94-95.
182 Exhibit 207.02, CAPP argument, paragraph 97.
183 Exhibit 81.04, prepared testimony of Mr. William B. Marcus, page 13, lines 3-10.

2009. For 2012, they recommended a common equity ratio of 30 per cent, due to the elimination of competition with NGTL.[184]

261. The CCA also expressed its opinion that ATCO Pipelines faces significant reductions to its business risks after integration and indicated that the company will be in danger of not recovering its revenue requirement only in the case of a default by NGTL. With respect to the competition from Alliance Pipelines, the CCA submitted that this risk may not materialize within the test years of this proceeding.[185]

262. As a result, the CCA argued that ATCO Pipelines' risks are no different from the risks faced by NGTL and recommended the equity thickness of 40 per cent in 2012, as awarded to NGTL by the National Energy Board. For 2011, the CCA recommended an equity ratio of 42 per cent, which is a weighted capital structure of 75 per cent pre-integration and 25 per cent post-integration, based on October 1, 2011 as the integration effective date.

### Commission findings

263. In Decision 2010-228, dealing with ATCO Pipelines' 2010-2012 revenue requirement settlement and system integration, the Commission accepted the approach proposed by the parties to that proceeding and agreed that ATCO Pipelines' equity ratio for 2010 and 2011 will exclude the impact of integration, while 2012 shall take integration into account.[186] Therefore, the Commission will base its determinations on ATCO Pipelines' 2011 common equity ratio taking into account any across-the-board adjustments applicable to all utilities, but without considering the impact of integration.

264. Furthermore, in Decision 2010-228 the Commission explained that post integration, ATCO Pipelines will collect its Commission approved revenue requirement through a monthly charge to NGTL, the ATCO Pipelines (AP) Charge. NGTL's revenue requirement, including the AP Charge, will be collected from customers using the combined regulated ATCO Pipelines and NGTL gas transmission systems, the Alberta System. Customers would pay one toll for use of the Alberta System and be subject to a single tariff with a single set of terms and conditions of service.[187]

265. All parties to this proceeding acknowledged that with this arrangement, the only risk of ATCO Pipelines not recovering its revenue requirement is if NGTL was unable to make its payments. As such, the Commission considers that in 2012, the business risks faced by ATCO Pipelines have been significantly reduced through its integration with NGTL.

266. The UCA and CAPP witnesses argued that the business risk of ATCO Pipelines post integration is comparable to the risk of Alberta TFOs, which recover their revenue from the AESO. However, the Commission considers that this comparison is not entirely accurate. Unlike the AESO, the combined ATCO Pipelines/NGTL system faces certain competition and supply risks (as presented in the Utilities' argument), which should be taken into account.

267. In light of the above considerations, the Commission finds that ATCO Pipelines' post integration business risk is higher than the level of risk faced by the electric transmission sector,

[184] Exhibit 210.02, UCA argument, paragraphs 202-204.
[185] Exhibit 211, CCA argument, paragraph 55.
[186] Decision 2010-228, paragraph 91.
[187] Ibid., paragraph 115.

but is somewhat lower than the risk of electric and gas distribution sectors. The Commission's determination on ATCO Pipelines' capital structure for 2012 presented in Section 5.6 below reflects these findings by setting the equity ratio at the average of those two sectors.

268. The Commission does not consider that this determination will have a significant impact on ATCO Pipelines' credit metrics. In the Commission's view, setting the equity ratio for ATCO Pipelines at the midpoint of that of the TFOs and the distribution utilities will be sufficient to attain the minimum credit metrics associated with credit ratings in the A range. This follows logically because the Commission will award equity ratios to those two sectors designed to achieve A ratings and the Commission has found that ATCO Pipelines' risk is midway between the risk of those two sectors. Furthermore, the Commission considers that if, after assessing the impacts of this decision, ATCO Pipelines remains concerned about its credit metrics, this matter can be addressed at the time of its next GTA.

### 5.5.4 Additional concerns raised by the UCA

269. As discussed in sections above, the UCA based its recommendations on the capital structures for the Alberta utilities based on Drs. Kryzanowski and Roberts opinion that:

- a two percentage point reduction was justified as credit markets have normalized
- the two percentage point increase awarded to the non-taxable utilities should be removed
- consideration of CWIP and lower tax rate in the credit metric analysis was not necessary

270. The Commission dealt with these recommendations in the sections above. In addition to these recommendation, Drs. Kryzanowski and Roberts suggested further reductions to equity ratios awarded in 2009 decision for certain utilities.

271. In particular, the UCA witnesses recommended that ENMAX TFO's equity ratio be set at 30 per cent, which is three percentage points lower than the EPCOR TFO's common equity ratio. The basis for Drs. Kryzanowski and Roberts' recommendation was that ENMAX Transmission had lower asset growth as compared to other TFOs in the province, and as such, its business risk (in particular, the asset replacement risk) was lower.[188]

272. Additionally, Drs. Kryzanowski and Roberts recommended differentiating the common equity ratios of ATCO Electric TFO and AltaLink. According to the UCA witnesses' calculations, taking into account the relief measures provided in Decision 2011-134,[189] a 34 per cent equity ratio was sufficient to maintain ATCO Electric's credit metrics above the minimum levels.[190]

273. Drs. Kryzanowski and Roberts also recommended that the equity ratio for ATCO Gas be set at 34 per cent, which was one percentage point lower than their suggested equity ratio for

188 Exhibit 81.02, prepared testimony of Drs. Kryzanowski and Roberts, page 81.

189 Decision 2011-134: ATCO Electric Ltd., 2011-2012 Phase I Distribution Tariff, 2011-2012 Transmission Facility Owner Tariff, Application No. 1606228, Proceeding ID No. 650, April 13, 2011.

190 Exhibit 146.02, rebuttal evidence submitted on behalf of the UCA, paragraphs 139-143.

electric distribution companies. The UCA witnesses indicated that the lower ratio for ATCO Gas reflects the reduction in business risk from its weather deferral account.[191]

274. Finally, the UCA pointed out that Drs. Kryzanowski and Roberts recommended a 90 basis point flexibility adjustment to the allowed return on equity to further ensure that the utilities are capable of maintaining a credit rating in the A range.

275. The Utilities argued that there was no legitimate basis for distinguishing between the capital structures of ENMAX and EPCOR TFOs. As well, the Utilities submitted that the evidence in this proceeding did not support the view that ATCO Electric TFO and AltaLink should have different common equity ratios on a generic basis. The Utilities submitted that both of these proposals violated the standalone principle. In addition, the Utilities argued that any individual differences among the awarded common equity ratios should be made on company specific basis as part of the GTA process, and not during the GCOC process.

### Commission findings

276. The approach of UCA and Drs. Kryzanowski and Roberts of adding 90 basis points to a common ROE in support of credit metrics presents some difficulties for the Commission.

277. In Decision 2004-052, the Commission's predecessor applied a generic ROE to all utilities and addressed the need for any utility-specific adjustments to the common ROE through the capital structure. Moreover, the board indicated that unique utility specific adjustments to the common ROE should only be made in exceptional circumstances where adjusting capital structure alone is not sufficient to reflect the investment risk for a particular utility.[192]

278. In Decision 2009-216, the Commission reiterated that it will adjust for any differences in risk among the utilities by adjusting their individual equity ratios.[193] The Commission has reaffirmed its adherence to this approach in this decision as well. As such, the UCA's approach to add 90 basis points to the ROE on order to support an A category credit rating contradicts the approach taken by the Commission.

279. Additionally, the UCA's proposal makes it difficult to compare its recommendations to those of the other participants or even to the 2009 GCOC decision. In order to assess the UCA's ROE recommendation on a comparable basis, one could perhaps deduct the 90 basis points adder. But this was not the position of the UCA and so the Commission does not favour this approach. Besides, if the Commission were to deduct the 90 basis points from the UCA's ROE recommendation, it is not clear what amount, if any, should be added to the UCA's equity ratio recommendations. Furthermore, the UCA did not present any analysis to show that an adder to the ROE was a more cost effective way to support an A range credit rating than adjusting to a higher equity ratio.

280. Given these considerations, the Commission has evaluated the UCA's ROE and equity ratio recommendations as if they were independent of each other.

281. The UCA's credit metric analysis and resulting recommendations on the common equity ratios for the Alberta utilities were based on the assumptions that CWIP and lower income tax

[191] Exhibit 81.02, prepared testimony of Drs. Kryzanowski and Roberts, paragraph 414.
[192] Decision 2004-052, pages 14 and 15.
[193] Decision 2009-216, paragraph 78 and 221.

rates are not included in the credit metric calculations.[194] As detailed in Section 5.3.2 above, the Commission did not agree with this premise.

282. Furthermore, the UCA's approach of differentiating capital structures of ENMAX and EPCOR TFOs, ATCO Electric and AltaLink TFOs, as well as further distinguishing between the capital structures of ATCO Gas and AltaGas, runs contrary to the Commission findings in Section 5.4 above and the UCA's own evidence that business risks have not materially changed since 2009.[195]

283. For example, the UCA indicated that its recommended equity ratio for ATCO Gas of 34 per cent was one percentage point lower than equity ratio of electric distribution companies due to the reduction in business risk from its weather deferral account. However, the Commission already considered this matter when determining the common equity ratios in 2009. As presented in Decision 2009-216, the Commission acknowledged the existence of the weather deferral account and determined that that ATCO Gas has a similar level of business risk compared to electric distribution companies.[196]

284. More importantly, Drs. Kryzanowski and Roberts acknowledged that their proposed equity ratios for ENMAX Transmission and ATCO Pipelines (in 2012), were inconsistent with the minimum equity ratios observed by the Commission.[197]

285. For these reasons, the Commission does not accept the UCA's recommendations regarding further reductions in equity ratios for ATCO Electric and ENMAX TFOs, as well as ATCO Gas.

### 5.6 Conclusion regarding required capital structures

286. The Commission has examined a number of factors that are relevant to determining the required equity ratios. These include a consideration of the recent developments in credit environment, the levels of key credit metrics that are associated with the actual credit ratings of relatively pure-play Canadian utilities, and certain utility-specific adjustments.

287. Two factors that could potentially impact the electric transmission sector were also examined; the impact of above historic trend growth and any risk associated with the potential for stranded transmission assets. Finally, several other factors specific to certain individual utilities were examined. These included the non-taxable status of a number of the utilities, the competitive situation facing ATCO Pipelines following its integration with NGTL, and differentiation of equity ratios among certain utilities as proposed by the UCA.

288. Accordingly, the Commission makes the following findings:

1. There is no need to reverse the adjustment to the Alberta utilities' capital structure that was provided in Decision 2009-216 to account for the financial crisis, because the effects of the financial crisis have not completely abated.

194 Exhibit 210.02, UCA argument, paragraph 222.
195 Exhibit 81.02, prepared testimony of Drs. Kryzanowski and Roberts, paragraphs 238 and 286.
196 Decision 2009-216, paragraphs 368, 371 and 412.
197 Ibid., paragraph 221.

2. The credit metric analysis of relatively pure-play Canadian utilities indicates that in order to target a credit rating in the A range: (i) the minimum equity ratio for Alberta utilities should be 37 per cent based on EBIT analysis, 30 to 38 per cent based on FFO/debt analysis and 35 per cent based on FFO interest coverage analysis; (ii) the minimum equity levels produced by the credit metric analysis in this decision are somewhat higher than the equity ratios estimated in Tables 13 to 15 of Decision 2009-216, however (iii) since the equity ratios approved in the 2009 GCOC decision meet or exceed the minimum levels recommended above, no across-the-board increase to the currently approved equity ratios for the Alberta utilities is required.

3. The business risk analysis does not indicate that there have been major changes in the relative risks of the various utilities segments, with the exception of ATCO Pipelines following its integration with NGTL. Hence, as in the case of the 2009 decision, any increase in equity ratios should be relatively uniform across the sectors and individual utilities unless utility-specific considerations require otherwise.

289. Given the Commission determinations with respect to the effects of the financial crisis, the results of the credit metric analysis, and the Commission's finding that the relative risks of the various utilities segments have not changed, the Commission finds that no across-the-board increase to the currently approved equity ratios for the Alberta utilities is necessary.

290. The Commission will now consider the need for any company-specific adjustments to equity ratios.

### ATCO Electric and AltaLink TFOs

291. As discussed earlier in this decision, recognizing the need to mitigate the impacts of the large capital build on ATCO Electric TFO and AltaLink TFO credit metrics, the Commission recently approved relief measures for these two companies in Decision 2011-134 and Decision 2011-453, respectively. These measures included the suspension of the current accounting treatment for CWIP (also known as CWIP in rate base) and approval for the future income tax method.

292. However, the credit metric relief packages approved for these transmission companies were based on the 2009-2010 approved ROE level of nine per cent, not the 8.75 per cent ROE approved in this decision for 2011 and 2012. With this reduction in the level of allowed return, the Commission considers that these two TFOs will not be afforded the level of relief intended in those decisions. In order to maintain the level of relief intended in Decision 2011-134 and Decision 2011-453, the Commission awards a one percentage point equity increase in the capital structure of ATCO Electric TFO and AltaLink TFO.

### ATCO Pipelines

293. As detailed in Section 5.5.3 above, ATCO Pipelines' equity ratio for 2011 would be reflective of any common adjustments applicable to all utilities, but without considering the impact of integration. Therefore, ATCO Pipelines is awarded a 45 per cent equity ratio for 2011, unchanged from its currently approved level.

294. In 2012, ATCO Pipelines' equity ratio is set at 38 per cent, which represents the mid-point between the awarded equity ratios for the electric transmission and electric distribution sectors (without considering the extra adjustment for the tax-exempt utilities).

**Table 10. Equity ratio findings**

| | Last approved (%) | 2011 approved (%) | Change in approved common equity ratio (%) |
|---|---|---|---|
| **Electric and Gas Transmission** | | | |
| ATCO Electric TFO | 36 | 37 | 1 |
| AltaLink | 36 | 37 | 1 |
| ENMAX TFO | 37 | 37 | no change |
| EPCOR TFO | 37 | 37 | no change |
| RED Deer TFO | 37 | 37 | no change |
| Lethbridge TFO | 37 | 37 | no change |
| TransAlta | 36 | 36 | no change |
| ATCO Pipelines | 45 | 45 for 2011<br>38 for 2012 | no change for 2011<br>(7) for 2012 |
| **Electric and Gas Distribution** | | | |
| ATCO Electric DISCO | 39 | 39 | no change |
| ENMAX DISCO | 41 | 41 | no change |
| EPCOR DISCO | 41 | 41 | no change |
| ATCO Gas | 39 | 39 | no change |
| FortisAlberta | 41 | 41 | no change |
| AltaGas | 43 | 43 | no change |

### 5.7 Future adjustments to capital structure

295. The equity ratios awarded in this proceeding will remain in place until changed by the Commission. Individual utilities, or interveners, may apply for changes to equity ratios on the basis of significantly changed circumstances.

## 6 Management fee matters

### 6.1 Background

296. The Utilities proposed a management fee as compensation for the provision of service involving assets funded by customer contributions in aid of construction (CIAC). The concept of a management fee had been previously proposed by ATCO Electric in its 2009-2010 General Tariff Application (Proceeding ID No. 86) and AltaLink in its 2009-2010 TFO Tariff Application (Proceeding ID No. 102). The proposed management fee applied for in those applications was intended to provide compensation for the risks and value of service associated with ownership, operation and maintenance of assets financed by CIAC. In Decision 2009-087[198] in respect of ATCO Electric's 2010-2011 General Tariff Application, the Commission stated:

> The Commission finds that consideration and evaluation of CIAC and related compensation to the utility could be more efficiently and effectively addressed going forward at a generic proceeding, which would allow for a more detailed review of all

[198] Decision 2009-087: ATCO Electric Ltd., 2009-2012 General Tariff Application – Phase I, Application No. 1578371, Proceeding ID. 86, July 2, 2009.

relevant issues at one time by all potentially affected parties. The Commission will advise all parties in the near future as to the process that will be established.[199]

297. The Commission issued a similar finding in Decision 2009-151[200] in respect of AltaLink's 2009-2010 TFO Tariff Application.

298. By letter dated December 16, 2010, the Commission determined that the consideration of a management fee would be included in the scope of this proceeding.

299. The Utilities engaged Ms. McShane to assist in developing its position in respect of the proposed management fee. Ms. McShane provided the following conclusions in her evidence in respect of the proposed management fee:

- The proportion of CIAC to total regulated assets for the Alberta Utilities in the composite is materially higher than for the typical non-Alberta utility.
- CIAC relates to assets that are constructed, owned, managed and operated by the utilities, but for which no compensation in the form of return, margin or fee is provided, despite the fact that the utilities bear risks related to them.
- The root cause of the size of the CIAC is the existing investment and contribution policies. Amending investment policies is required but the mitigation will only occur over time and the Alberta Utilities should be afforded compensation for services rendered with respect to facilities funded in whole or in part by CIAC.
- The approach adopted to determine the amount of compensation that is reasonable for CIAC funded assets has been derived from the increase in the cost of equity that results from the reduction in the utilities' effective equity ratio due to the presence of debt-like CIAC. The compensation determined from this analysis, estimated as a return on CIAC, is two per cent. For taxable utilities the two per cent margin needs to be grossed up for income taxes to allow the utilities to earn the two per cent margin on an after-tax basis. The two per cent estimated return is supported by applying the approach used in the past by the Ontario Energy Board (OEB) to derive a reasonable return for deferred tax balances.
- The proposed two per cent return would be applied to CIAC balances that exceed four per cent of total rate base, inclusive of CIAC. The four per cent threshold was based on the average contributions as a per cent of gross rate base for nine non-Alberta regulated utilities as provided in Table 1 of Ms. McShane's evidence.
- The existing capital structures and ROE's, which were awarded in the absence of any consideration of CIAC, do not provide any compensation for CIAC.[201]

300. Ms. McShane stated that, in the absence of significant rate base upon which to determine a reasonable return, regulators have adopted alternative methodologies to provide a measure of return to the regulated utilities and noted the following examples:

199 Decision 2009-087, paragraph 38.

200 Decision 2009-151: AltaLink Management Ltd. And TransAlta Corporation, 2009 and 2010 Transmission Facility Owner Tariffs, Application No. 1587092 and Application No. 1594573, Proceeding ID. 102, October 2, 2009.

201 Exhibit 86.01, opinion on management fee and Rider I, lines 27-73.

- The Commission and its predecessors have adopted the concept of a return margin in the case of regulated rate tariffs where there is little rate base.
- The Independent Assessment Team[202] recommended the adoption of a minimum return margin in respect of the power purchase agreements related to the heritage electricity generation plants to address the issue of rising operating leverage as the generating plants reached the end of their accounting lives.
- The Federal Energy Regulatory Commission (FERC) adopted a management fee in cases of pipelines that are largely depreciated.[203]

301. Ms. McShane stated that the point of departure for the recommended approach is the recognition that (1) the higher the level of CIAC relative to the total rate base, the higher is the operating leverage; and (2) the higher the level of CIAC relative to total capital (inclusive of CIAC) the higher is the financial risk. Ms. McShane noted that operating leverage referred to the sensitivity of the earned return on rate base to unanticipated changes in revenues and/or costs.[204]

302. The Utilities' management fee proposal centered, however, on the issue that CIAC relates to assets that are constructed, owned, managed and operated by the Utilities, but for which no compensation in the form of return, margin or fee is provided despite the fact that the Utilities bear risks related to these assets and use them to provide valuable services.[205]

303. Conceptually, the management fee proposed by the Utilities involves a fee that would be included in the revenue requirement calculated as two per cent of each utility's remaining unamortized CIAC balance in excess of four per cent of its total assets. The Utilities summarized the calculation of the annual management fee in their argument as follows:

> The annual Management Fee should be calculated by (1) summing the mid-year approved CIAC balance and rate base net of other forms of no cost capital (i.e. mid-year pro-rated invested capital); (2) calculating 4% of the total; and (3) subtracting the 4% from the forecast test-year CIAC balance. The resulting balance equals the CIAC eligible for Management Fee. The management Fee in dollars for each of the Alberta Utilities would then be calculated by applying the requested 2% to the eligible CIAC balance. For the taxable utilities, the resulting Management Fee would then be grossed up by the test year corporate income tax rate.[206]

304. The UCA engaged Mr. William B. Marcus to assist in developing its position in respect of the proposed management fee, among other things. Mr. Marcus, in his evidence, submitted that he is opposed to the proposed management fee for the following reasons:[207]

202 The Independent Assessment Team (IAT) was appointed under provisions included in April 1998 amendments to the *Electric Utilities Act*. The scope and duties of the IAT were set out in the *Electric Utilities Act*, and were focused on two major areas: assessment and determination of the PPAs, and design of the auction process (see Decision U99073: Board Review of the Independent Assessment Team's Report on Power Purchase Arrangements and other Determinations (Issued: August 30, 1999)).

203 Exhibit 86.01, opinion on management fee and Rider I, lines 234-265.

204 Exhibit 86.01, opinion on management fee and Rider I, lines 361 to 366.

205 Exhibit 86.01, opinion on management fee and Rider I, lines 216-224.

206 Exhibit 209.01, Utilities argument, paragraph 260.

207 Exhibit 81.04, prepared testimony Mr. William B. Marcus, pages 43 and 44.

- It upsets the regulatory compact, where a utility earns a return on invested capital commensurate with the company's business and financial risk, by providing a return on capital that the utility does not actually invest, even though the business and financial risks of the entire company – including contributed property –have already been considered when setting the capital structure and return on equity.
- The proposal made by utilities in the past completely negates the purpose of CIAC by forcing ratepayers to pay the same equity return on contributed property as they would pay had the utility simply put everything in rate base and had no contribution policy at all. All that is saved is the cost of debt.
- Giving shareholders an equity return on contributions without requiring them to actually invest any equity will enrich shareholders far more than if contributions were simply abolished. This comparison shows that paying an equity return on contributions will provide shareholders with an outsized and unreasonable return.
- What is actually being "managed" for contributed property is O&M expense. These expenses and the cost and risk of managing these expenses are included in rates, and the increase in contributions has not resulted in a significant increase in the utilities' total business risk.
- A management fee for contributions is a solution in search of a problem. Alberta has had high levels of distribution contributions literally for decades. Contributed transmission property has increased somewhat in recent years but is still on the order of 10 per cent of total transmission assets. Many of those assets are in fact contributed by the distribution company.

305. By letter dated August 5, 2011 the Commission set out a final issues list for argument and reply. The management fee section of this decision addresses the issues in respect of the proposed management fee as set out in Attachment 1 to the Commission's August 5, 2011 letter.

## 6.2 Views of the parties

### 6.2.1 Is a management fee compatible with the fair return standard and the paradigm of paying a return on capital invested in rate base?

306. The Utilities argued that the proposed management fee provides the utilities with fair compensation for providing valuable services and bearing the risks associated with the construction, ownership, operation and management of CIAC-financed assets and submitted that parties objecting to the management fee have ignored the unfairness arising from the utilities' obligation to provide services in relation to CIAC-financed assets for no compensation.

307. The Utilities also argued that the management fee is compatible with the legal framework as well as the fair return standard and that it provides for fair compensation for utility services rendered. Finally, the utilities stated that the management fee constitutes a fee or a just and reasonable charge for service rather than a fair return, which is legally separate and compensates the utility for something different. The Utilities stated that the two concepts, though independent of each other, are complementary.[208]

[208] Exhibit 209.01, Utilities argument, paragraphs 162 to 165.

308. The UCA submitted that the type of management fee proposed by Ms. McShane on behalf of the Utilities is not consistent with the fair return standard or the paradigm of paying a return on capital invested in rate base. The paradigm is cost-based rates, the UCA submitted, under which utilities are permitted to charge rates that will give them a reasonable opportunity to recover their prudently incurred costs, including the cost of the debt and equity capital they have invested in the business.[209]

309. The UCA argued that CIAC collected from customers by the Utilities represents capital that has been invested by the Utilities that has no cost associated with it. By effectively allowing shareholders to earn a return on the no-cost capital contributed by third parties, the UCA submitted, the management fee proposed by the Utilities would enable the Utilities, and ultimately their shareholders, to earn amounts in excess of their costs, including a fair return on the equity capital that has been invested by shareholders.[210]

310. The CCA agreed with Mr. Marcus and submitted that a management fee is incompatible with a fair return standard on invested capital. The CCA considered that the use of a management fee and a fair return on rate base and construction work in progress, or plant held for future use, results in excessive returns to the utility. The CCA also agreed with Mr. Marcus that a management fee is inconsistent with cost-based rate-making principles and it is inappropriate to award a utility a return, in the form of either a return on investment or a management fee, on the assets financed by customers.[211]

311. IPCAA submitted that the Utilities are asking to be compensated as if they had invested in the customer contributed facilities they are managing. Where facilities have been paid for by customers through customer contributions, rather than by the utility, IPCAA submitted that there is no equity injection by the utility and no concomitant risk accompanying such an investment. IPCAA submitted that the management fee proposal before the Commission is incompatible with the fair return standard and the paradigm of paying a return on capital invested in rate base.[212]

312. IPCAA submitted in reply argument that the Utilities receive cost of service compensation for the operation, maintenance and 'management' of CIAC-financed assets, so the Utilities statement in argument that "the Utilities receive no compensation relating to CIAC-financed assets" is incorrect and that compensation may or may not include a profit component. The Utilities, IPCAA submitted, as with all utilities in Alberta (and almost all of North America) are regulated on a cost of service basis and receive recovery of all reasonably incurred costs for services rendered. The Utilities receive such compensation for all CIAC assets, IPCAA argued, and no other form of compensation is warranted or indeed permitted.[213]

313. IPCAA noted that the Utilities themselves state, with respect to the risk of stranded TFO assets, that "the regulatory compact in Alberta has been such that tariffs are to, and do, provide the opportunity to recover the costs of prudent investments in the system." IPCAA stated that the Utilities make IPCAA's point; that there is nothing in the regulatory compact which allows a utility to recover compensation over and above its prudent costs of services provided. Profit is

209 Exhibit 210.02, UCA argument, paragraph 232.
210 Exhibit 210.02, UCA argument, paragraph 232.
211 Exhibit 211.01, CCA argument, paragraph 59.
212 Exhibit 212.01, IPCAA argument, paragraph 17 and 18.
213 Exhibit 222.01, IPCAA reply argument, paragraph 2.

possible on investments, just as the Utilities note, and only on investments. IPCAA submitted that utility investment has always been net of CIAC investment.[214]

314. IPCAA stated that services such as providing operations and maintenance services have been paid by the cost recovery of operation and maintenance expenses, excluding a profit component. All the items of allowable costs are set out in Section 122(1) of the *Electric Utilities Act.* This reflects the regulatory compact as it exists in Alberta, and it is this compact that the Utilities appear to want to defend on the one hand (with respect to the risk of stranded TFO assets) and undermine on the other hand (in the context of a management fee).[215]

315. CAPP submitted that the Utilities argument that a management fee is separate from the fair equity return to be allowed the equity investor is paradoxical since the management fee is nothing more or less than compensation to the equity investor. It is the equity investor that is the intended recipient of the fee and the result is to increase the return to the equity investor. CAPP submitted that gas utilities like ATCO Pipelines have been collecting customer contributions for decades without it ever being suggested that the equity investor was being short changed. If utility equity investors were being short changed all these many decades it would have been evident in market data long before now.[216]

316. In reply, the Utilities countered the assertions made by IPCAA and CAPP that the Utilities are compensated for costs incurred in respect of CIAC assets by stating that mere cost recovery is not compensation for valuable services rendered. The Utilities agreed that, where CIAC levels approximate the industry average, the conventional model generally provides fair and reasonable compensation. However, the Utilities noted that CAIC levels are significantly higher in Alberta than the industry average and, as a result, the paradigm does not provide fair compensation, or any compensation, in relation to services provided and risks borne in relation to CIAC-funded assets. The Utilities reiterated that the proposed management fee augments the conventional model, it does not supplant it.[217]

### 6.2.2 Does the Commission have the jurisdiction under its governing legislation to provide for a management fee?

317. The Utilities argued that the proposed management fee addresses a fundamental issue of fairness and that, consistent with the fundamental principles of utility regulation and the regulatory compact, regulated entities should not be expected to provide service to customers for zero compensation.[218] Consequently, the Utilities asserted that they should be fairly compensated for the risks undertaken and the services provided to ratepayers using CIAC-financed assets.

318. With regard to the Commission's jurisdiction to award a management fee, the Utilities referred to sections 121(2) and 122(1) of the *Electric Utilities Act as* establishing the basis for a utility to recover costs and expenses associated with the provision of necessary services to customers.

319. The Utilities argued that CIAC assets are indistinguishable from other utility assets and so the Utilities should be provided an opportunity to earn fair compensation for services the

214 Exhibit 222.01, IPCAA reply argument, paragraph 3.
215 Exhibit 222.01, IPCAA reply argument, paragraph 4.
216 Exhibit 217.02, CAPP reply argument, paragraphs 19, 20, and 21.
217 Exhibit 220.02, Utilities reply argument, paragraphs 109-111.
218 Exhibit 209.01, Utilities argument, paragraph 163.

Utilities are mandated to provide using CIAC-financed assets. The Utilities stated that the Commission should approve the management fee consistent with the Commission's statutory obligation to provide just and reasonable compensation per Section 121(2)(a) of the *Electric Utilities Act.*

320. With respect to gas utility-related legislation, the Utilities cited Section 4(3) of the *Roles, Relationships and Responsibilities Regulation* as the basis for a gas utility's recovery of costs and expenses associated with the provision of necessary services to customers and stated that sections 36(a) and 45 of the *Gas Utilities Act* contemplate that regulated utilities will receive reasonable compensation for the services they provide.

321. The Utilities took issue with the interveners' characterization of the management fee as a return on monies not invested, stating that the Utilities are instead requesting fair compensation in the form of a separate fee or just and reasonable charge commensurate with the value of services rendered that is distinguishable from fair return.

322. The Utilities argued that the right to be fairly compensated for services provided to ratepayers through the use of utility assets is a fundamental underpinning of the regulation of utilities, and has been previously recognized by the Courts. In contrast to the position of interveners, the Utilities argued the presence of cost of service references in the legislation does not preclude the Commission from awarding a management fee.

323. Even in the absence of any statutory provision, the Utilities stated that consumers would have imposed upon them an obligation at common law to pay for the service on the basis of *quantum meruit,* as part of the undoubted jurisdiction to ensure that tolls are at all times just and reasonable. In support of this, the Utilities cited the Supreme Court of Canada's decision in *City of Edmonton et al. v. Northwestern Utilities Ltd*:[219]

> The right of the consumers to require the respondent to supply them with gas, conferred by the statute, would, in my opinion, even in the absence of any statutory provision, impose upon them an obligation at common law to pay for the service on the basis of quantum meruit. In such circumstances, I consider that the position of the utility would be similar to that of a common carrier upon whom is imposed, as a matter of law, the duty of transporting goods tendered to him for carriage at fair and reasonable rates. (Great Western R. Co. v. Sutton (1869), L.R. 4 H.L. 226 at 237). Here the duty of determining what rates are fair and reasonable is imposed upon the board.(…) [Emphasis added.]

324. The Utilities cited *Sullivan on the Construction of Statutes* to support the position that there exists a presumption that legislation is not intended to alter the common law but that the common law is meant to be incorporated. Absent clear legislative intent to the contrary, the Utilities argued, a utility has the right to receive just and reasonable compensation for providing services that it is legally obligated to provide.

325. Accordingly, the Utilities stated that:

> (E)ven if one were to ignore the provisions of applicable legislation, which provide for fair compensation for utility services rendered and obligate the Commission to ensure

219 *City of Edmonton et al. v. Northwestern Utilities Ltd.*, [1961] S.C.R. 392 at 401(*Northwestern 1961*).

that tariffs are just and reasonable, the Utilities are entitled to fair compensation based on principles of *quantum meruit*, for value of service rendered. Yet, the current treatment of CIAC does not provide any compensation to the Utility, let alone fair compensation dictated by the common law principles of *quantum meruit*, which is also encompassed in the legislative requirement that rates be just and reasonable.[220] [footnotes omitted]

326. In response to the question of whether the Commission has the jurisdiction under its governing legislation to provide for a management fee, the UCA noted that the general approach of limiting utility rates to a cost-based level has been developed and applied by North American utility regulators, including the Commission, for some time. The UCA stated that, in many jurisdictions, the governing statutory requirement is simply that rates be just and reasonable, and not unjustly or unduly discriminatory. In those jurisdictions, the UCA submitted, the legislature has left the determination and definition of the "just and reasonable" standard to the regulators.

327. The UCA distinguished the situation in Alberta, where it argued that the legislature has gone further and codified a requirement for conventionally determined cost-based rates in the relevant statutes. The UCA noted that, under Section 90 of the *Public Utilities Act*, in order to fix just and reasonable rates, the Commission is required to determine a rate base for the property of the owner of the public utility that is used or required to be used to provide service to the public, and fix a fair return on that rate base. The UCA also cited Section 122 of the *Electric Utilities Act* which states that, when considering a tariff application, the Commission must have regard for the principle that a tariff approved by it must provide the owner of the electric utility with a reasonable opportunity to recover the costs and expenses associated with the capital related to the owner's investment, including a fair return on the equity of shareholders of the utility as it relates to the investment.

328. The UCA argued that conventionally determined cost-based utility rates are not only just and reasonable, as a matter of economic and regulatory theory, but are therefore also required by the relevant Alberta statutes. To the extent a management fee would enable the utilities to recover, on an expected basis, amounts in excess of their costs, including a fair return on equity, the UCA submitted that such a fee is not permitted by the statutes.

329. The UCA also noted the Utilities' argument that the principle of *quantum meruit* operates, notwithstanding the provisions of the *Electric Utilities Act* and *Gas Utilities Act*, to give the Utilities a common law or equitable right to compensation for the value of services provided using CIAC-financed facilities in addition to their statutory right to charge rates that enable them to recover their costs, including a fair return.

330. The *quantum meruit* principle, the UCA submitted, is an equitable doctrine that enables the Courts, based on specific factual circumstances, to award compensation for services rendered in situations where the person providing the service should be entitled to receive some level of compensation on "equitable grounds" and is not entitled to any compensation under contract, statute, or on other legal grounds. The UCA argued that the Utilities do not provide any services that they are not compensated for, and the compensation they receive is set at a level that meets the requirements of the applicable statutes. Thus, the UCA submitted, there are no uncompensated-for services for the *quantum meruit* principle to apply to.

[220] Exhibit 209.01, Utilities argument, paragraph 176.

331. The UCA took issue with the notion that the Utilities appeared to be suggesting that the *quantum meruit* principle applies not just to whether they receive compensation for services they provide, but to the level of that compensation. The UCA argued that to claim that the principle provides for a common law or equitable right to require the Commission to set rates at a level that is higher than a cost-based level, if the value of the services provided by the Utilities exceeds the cost of providing them, is inconsistent with the *Electric Utilities Act* and the *Gas Utilities Act* as well as the *Northwestern* decision and cannot be correct.

332. Approval of the management fee proposal would, the UCA argued, result in rates that are higher than are necessary to enable the Utilities to recover their prudently incurred costs, including a fair return. It would also, the UCA argued, result in profits or returns to shareholders that exceed the cost of equity capital and the levels dictated by the fair return standard, and it would result in rates that are not just and reasonable under any normal conception of that expression.

333. The CCA submitted that a management fee and return on invested capital results in excessive returns to the utility and that the awarding of an excessive return in the form of a management fee and return on invested capital is beyond the AUC's jurisdiction.

334. IPCAA submitted that the Commission did not have the jurisdiction to award the management fee in the form requested by the Utilities, as such a fee would only be justified if the Utilities had made an equity injection with respect to the subject facilities. IPCCA argued that Section 122(1) of the *Electric Utilities Act* did not support the Utilities' proposal as the Utilities already received cost recovery under those provisions. IPCAA argued that the management fee as proposed would grant recovery over and above the costs and expenses incurred by the Utilities in managing these facilities and that is not permitted under Section 122. IPCAA also disagreed with the Utilities' argument that the Commission "should approve the Management Fee, consistent with the Commission's statutory obligation to provide just and reasonable compensation per section 121(2)(a) of the *EUA*," stating that Section 121 was a general section, the type seen in virtually all similar statues.

335. IPCCA stated that the Utilities' arguments that "compensation commensurate with value of service rendered is a common law right" and that "regulated entities have never been expected to provide service to customers for no compensation" ignore both the compensation the Utilities receive for 'managing' CIAC assets and the law. IPCAA submitted that the regulatory compact, as reflected in the *Electric Utilities Act,* compensates utilities for services performed on the basis of the cost of service model and that, conversely, return of and on equity is precisely that; namely, return on the equity component of capital invested by the utility, and no more profit beyond that.

336. Arguing that the Utilities' statement that the "net rate base model focuses solely on the concept of cost of service, with no consideration given to the value of the services provided" is misleading, IPCAA submitted that it was more accurate to say that the cost of service model is used as a proxy for the value of services rendered by a utility.

337. IPCCA also argued that the Utilities' management fee proposal runs contrary to the regulatory compact and could equally apply to all other costs incurred by utilities in providing service. As an example, IPCCA noted that the cost of debt has always been recovered on a cost of service basis with no component for profit. If the Utilities' "illogic" was followed, IPCAA

argued, then investment covered by debt is also a "valuable service" and should be entitled to a profit in addition to the recovery of debt costs.

338. CAPP submitted that utility investors are allowed a return of and on their investment and that the law does not allow utility investors to get a return on money they have not put into the business. CAPP argued that the modern regulatory statute completely replaces the common law with regard to payment for utility services. The fair and reasonable compensation for common carriers under common law spoken of by Justice Locke in *Northwestern 1961*, CAPP argued, is now not a matter of *quantum meruit* as that may be measured by a judge in a civil action, but is to be determined in accordance with the principles established by statute by expert regulatory commissions.

339. The rate of return/rate base model is the law in Alberta, CAPP argued, which means equity investors earn a return on their equity investment, while debt investors earn a return on their debt investment. CAPP noted that the equity investor does not get a return for the management of the assets funded by debt: neither does the debt investor get a return for the management of the assets funded by equity. Likewise, CAPP argued, neither the law nor the model allows for a return on money that comes cost free from the customer. CAAP submitted that there is no unfairness in that, just as there is no unfairness in the equity investor getting, to paraphrase Ms. McShane, "zero profit" on the debt.

340. CAPP argued that the Utilities provide no legal authority that would suggest that the legislated scheme of rate-of-return/rate base regulation fails to set a reasonable price for service. Moreover, such an argument would go to the roots of the legislation and could not be confined to one issue like management fees.

341. CAPP submitted that what the utility gets for managing the assets, over and above the rate of return on rate base, is the recovery of all proper costs of operating the system. CAPP cited *Northwestern 1961* in support of the concept that the return on the capital invested by the investor is "net":

> In approving rates which will yield a fair return to the utility upon its rate base, it is, of course, essential for the Board to estimate the expenses which will necessarily be incurred thereafter in rendering the service. The fair return permitted is, after deducting from the gross revenue these necessary estimated expenditures and such necessary outgoings as taxes, including income taxes. The Board can only come to a conclusion as to what rates should be approved by determining as closely as may be done in advance the probable amount of these expenditures.[221]

342. Citing *Stores Block*, CAPP submitted that the entire discussion in that decision is premised on investment by private investors, not by customers, as is clear from the following passage:

> The capital invested is not provided by the public purse or by the customers; it is injected into the business by private parties who expect as large a return on the capital invested in the enterprise as they would receive if they were investing in other securities possessing equal features of attractiveness stability and certainty (see *Northwestern 1929*, at p. 192). This prospect will

[221] *Northwestern 1961* at page 405.

necessarily include any gain or loss that is made if the company divests itself of some of its assets, i.e., land, buildings, etc.[222]

343. CAPP argued that, if the customers, in addition to contributing free capital to obtain service (and so lower rates than would otherwise have been the case if the utility had made the investment), were to be required to pay the equity investor a return to manage that customer's capital contribution then it calls into question the rationale of *Stores Block.*

344. CAPP submitted that it is only in those rare few cases of the vanished rate base that the management fee comes into play since, otherwise, the equity investor would receive no return. In such cases the management fee is a substitute for the return on equity capital. It may also be observed that, when the utilities cite such rare cases of vanished rate base as precedent, they completely contradict their argument that the management fee issue is separate and distinct from the fair return.

345. With respect to the Utilities' argument regarding *quantum meruit*, CAPP submitted that *quantum meruit* applies in common law to the provision of goods or services that have been provided in the expectation of payment and where there is no contract that applies to the price for those goods or service. In this case, CAPP argued, here is a contract for the provision of services by the utility to the customer and it is governed by the tariff approved by the regulator. The approved tariff specifies the price to be paid and the terms and conditions including when the utility is not obliged to finance an investment in plant and the customer must finance the investment with the customer's own capital.

346. CAPP submitted that the provision of customer contributions is a creation of the regulatory model: it is not something that stands outside the regulatory model that is governed by common law principles and there is no gap to be filled by common law principles. CAPP argued that judicial observations, in obiter dicta, to the effect that regulatory statutes are consistent with *quantum meruit*, a concept that applied to common carriers at common law, do not assist the Utilities' argument.

347. In reply argument, the Utilities noted that there was no disagreement that the Commission is charged with ensuring that, in setting rates, it provides the utility a reasonable opportunity to recover its prudently incurred costs, including a fair return on investor-supplied capital.[223] The Utilities asserted that an economic cost or opportunity cost, which reflects normal profit for the service rendered, is therefore recognized as legitimate for cost recovery: the Utilities noted return on equity as an example, citing *TransCanada Pipelines Limited v. Canada (National Energy Board),* 2004, FCA 149, at paragraphs 6-12 and 32-34 as authority that such costs are recoverable in rates. The Utilities asserted that the management fee, like return on equity, is an economic cost as opposed to an incurred cost.[224]

348. The Utilities distinguished CAPP's discussion of the *Stores Block*[225] decision, stating that that decision dealt with a different matter (i.e., asset disposition not CIAC) and argued that it did not displace the utility's right in law to receive fair compensation commensurate with the value of services rendered.

222 *Stores Block* at paragraph 70.
223 Exhibit 220.02, Utilities reply argument, paragraph 115.
224 Exhibit 220.02, Utilities reply argument , paragraph 117.
225 *ATCO Gas &Pipelines Ltd. v. Alberta (Energy &Utilities Board*), [2006]1 S.C.R. 140 (*Stores Block*).

### 6.2.3 Should the utilities receive a fee for management of contributed assets? If so, should a management fee be awarded in addition to the allowed rate of return or can the ROE be adjusted to include compensation for the management of CIAC? Alternatively, can the ROE remain constant and a management fee be awarded through adjustments to the debt/equity ratio of individual utilities?

349. The Utilities argued that CIAC funded assets are fully integrated into other regulated assets that the Utilities own and operate and that the services that the Utilities provide to the customers that make contributions are the same as for all other customers. The Utilities stated that the only difference is that the Utilities do not finance CIAC assets and do not receive any compensation, or margin, either for providing valuable services related to, or for bearing risks associated with, constructing, owning, operating, and managing those assets.[226] The Utilities submitted that they should earn a margin or fair compensation for all of the service they render using all of the assets employed in rendering such service.

350. In argument, the Utilities noted Ms. McShane's evidence that in a "real world" competitive market, a business would expect to be compensated for the totality of the resources that it deploys, including physical capital and labour and enterprise capital. Further, in competitive markets, in economic terms, firms expect to earn a normal rate of profit; where a normal rate of profit recognizes the opportunity costs of all the resources devoted to the business. Finally, the Utilities noted that there are numerous competitive industries that have very little invested debt and equity, because they are primarily service industries (a number of which were identified in response to UCA-Utilities-48). Firms in these industries would all expect to generate a profit from the services that they provide irrespective of the fact that there is little invested capital. And, like the Alberta Utilities, these firms would expect to generate a profit on the totality of their business, not just some of their business operations.[227]

351. The Utilities stated that the size of CIAC is a problem unique to Alberta and noted that, in aggregate, total unamortized CIAC of the Alberta Utilities in 2007 was approximately $1.3 billion out of a total rate base net of contributions of approximately $6.6 billion and that, based on 2010 estimated data, CIAC accounts for approximately 16 per cent of gross rate base. The Utilities stated that there is a significant disparity between the percentage of CIAC of the Alberta Utilities and that of their Canadian peers and noted that, for a typical regulated Canadian utility, the CIAC to total rate base percentage is less than four per cent.[228] In Table 1 of her evidence, Ms. McShane provided the following list of regulated Canadian utilities and their contributions as a per cent of gross rate base:

226 Exhibit 209.01, Utilities argument, paragraphs 181 and 182.
227 Exhibit 209.01, Utilities argument, paragraphs 184 to 186.
228 Exhibit 209.01, Utilities argument, paragraphs 187 and 188.

**Table 11. Proportion of contributions to gross rate base for ex-Alberta utilities**

| Utility | Contributions as a Per cent of Gross Rate Base |
|---|---|
| Foothills Pipelines | 0.6% |
| FortisBC | 8.8% |
| Gaz Metro | 3.9% |
| Maritime Electric | 4.5% |
| Newfoundland Power | 2.8% |
| PNG-West | 3.8% |
| Terasen Gas | 6.3% |
| TransCanada Pipelines | 0.5% |
| Westcoast Energy | 0.5% |
| **Median** | **3.8%** |

352. The Utilities submitted that limiting the application of the two per cent margin to CIAC balances in excess of four per cent of gross (inclusive of contributions) rate base would appropriately recognize the fact that other utilities in Canada, that could be considered comparable to the Alberta Utilities, also have some CIAC, albeit in generally smaller proportions.[229] The Utilities noted that some level of contributions may be needed to help maintain fairness amongst customers but the current regime neglects to address the fairness issue as between customers and the Utilities. The Utilities refuted Mr. Marcus' assertion that the requested management fee would "negate" the purpose of contributions stating that receiving compensation where compensation is merited does not negate the purpose of contributions, since customers are not paying what they would pay if the CIAC-financed assets had instead been fully funded by investor supplied capital. The Utilities noted that a utility would not choose to construct, own, operate and manage assets on which it receives no profit margin but it has no choice since it is mandated to do so.

353. The Utilities stated that the management fee was recommended independently of the generic ROE and the capital structures appropriate for each utility, that it was a separate compensation from the fair return on rate base and that it would compensate the Utilities for something not compensated for under the existing cost of service regulatory scheme. The Utilities stated that the two concepts, fair return on rate base and the management fee, are complementary, with the management fee augmenting the traditional rate base/rate of return model to ensure fair compensation to the Utilities.[230] The Utilities noted that, during the oral proceeding, Ms. McShane confirmed that the need for a management fee arises because the traditional rate base/rate of return model does not fit the unique circumstances of the Alberta Utilities and does not afford adequate, or any, compensation for opportunity cost or value of service. The Utilities noted that, in addition to the value of services rendered, there are business risks and liabilities, other than the operating leverage risk, that the utilities are exposed to and for which the Utilities should be separately compensated in the management fee.

[229] Exhibit 209.01, Utilities argument, paragraph 189.
[230] Exhibit 209.01, Utilities argument, paragraph 194.

354. The Utilities took exception to Mr. Marcus' suggestion that, if the Commission is compensating for anything other than risk, then only a minimal amount should be awarded. The Utilities stated that the position advanced by Mr. Marcus downplays the risks taken and the value of services provided and the point that Mr. Marcus ignores is that the functions performed by the Utilities in relation to CIAC extend beyond operating and maintaining assets and included, for example, building transmission substations on, in effect, a turnkey basis for no compensation. Since constructing assets comprises a significant portion of activities associated with CIAC, the Utilities stated that this was further evidence that Mr. Marcus is undervaluing the services provided by the Utilities and that his "percentage adder on O&M" approach does not provide a reasonable estimate of that value.

355. The Utilities noted that IPCAA opposed the management fee on the basis that:

> IPCAA also believes the TFO's management fee proposal has an element of double charging. This potential for double charging is a matter of particular concern in the case of the customer who has already made a customer contribution since the additional management fee for the same assets adds no value.[231]

356. The Utilities submitted that IPCAA's reasoning is flawed and that there is no double charging since the Utilities do not recover the cost of capital provided by customers. Rather, the Utilities would now recover a fee for the valuable construction, operation and maintenance activities associated with continuing utility service.[232]

357. The Utilities noted that the Commission has previously acted to ensure that entities it regulates receive fair and reasonable compensation for the functions they perform and services they render in circumstances where the traditional cost of service methodology did not render appropriate results. The Utilities made reference to the retail energy providers who have little invested capital and are compensated by way of a return margin. In addition, the Utilities made reference to other jurisdictions in Canada and the U.S. where regulators have augmented the rate base/rate of return model in order to provide fair compensation to the utility. The Utilities noted that, while the circumstances of the Alberta utilities are not identical to those cited, the examples from these other jurisdictions provide a useful precedent for the regulatory approach the Utilities are proposing.[233]

358. The Utilities noted that Mr. Marcus acknowledged that, when the proportion of CIAC to total rate base becomes sufficiently large, the rate base/rate of return model may need to be replaced with an alternative.[234] The Utilities then stated that, as Mr. Marcus appears to agree with the concept of providing compensation or a margin for services rendered and risks assumed, the only disagreement appeared to be a question of how much CIAC is required to trigger payment of a service fee.[235]

359. In responding to the submission by various parties that contributions are already taken into account when setting the capital structure and return on equity, the Utilities stated that recovery of a utility's cost of capital does not address compensation for services provided

231 Exhibit 82.02, IPCAA Rider I evidence, pages 5 and 6.
232 Exhibit 209.01, Utilities argument, paragraphs 199 and 200.
233 Exhibit 209.01, Utilities argument, paragraph 202.
234 Exhibit 209.01, Utilities argument, paragraph 202.
235 Exhibit 209.01, Utilities argument, paragraph 203.

utilizing customer supplied capital. The Utilities stated that the recommended capital structure and ROE for the Alberta Utilities have been made independently of the issues related to CIAC. The Utilities submitted that there is no evidence the Commission or its predecessors have, either explicitly or implicitly, reflected the value of services provided with respect to, or risks related to, CIAC in setting the capital structures or ROE's in prior cost of capital decisions for Alberta Utilities.[236] They noted that the CIAC issue did arise with respect to AltaGas Utilities in the 2004 GCOC proceeding but stated that there was no reference to CIAC in the determination of relative business risk. Finally, the Utilities noted that the Commission determined that the management fee issue, when raised in other proceedings, should be considered on a more comprehensive industry wide basis in a subsequent proceeding. The Utilities stated that this was clear recognition from the Commission that the issue had not been previously determined.[237]

360. The Utilities addressed the fact that Interveners raised the timing of the management fee proposal and stated that no adverse inference can be drawn for the fact that the Utilities did not address the CIAC issue in prior cost of capital recommendations and that this simply reflected that, until recently, the Utilities attempted to deal with the CIAC issue through proposed changes to investment policy rather than seeking higher returns or thicker equity ratios.[238]

361. The Utilities stated that their position is that the management fee should be implemented as a separate revenue requirement item distinct from ROE and capital structure. The Utilities proposal maintains the traditional rate base/rate of return construct as regards investor supplied capital and, as such, the ROE must remain the same for each of the Utilities.

362. The Utilities also stated that implementing the management fee as a separate revenue requirement item would appropriately reflect the fact that the two concepts compensate for something different. The fair return relates to assets that are financed by the utility whereas the management fee relates to assets that are constructed, owned and operated by the utility but are financed by customers. As there is no overlap and the compensation for each is arrived at independently, there is no basis for accounting for the management fee through an adjustment to ROE. Accounting for it through ROE also loses the scalability feature of the management fee proposal which would award each utility a fee calculated only on the proportion of CIAC each utility has at any particular point in time.[239] Further, the Utilities submitted that there is no valid basis for reducing the allowed return on account of a management fee.[240] They also stated that while ROE and capital structures are assessed against "comparable" companies, those firms do not have the high levels of CIAC experienced by the Alberta Utilities, therefore, the fair return does not account for the CIAC assets.[241] Finally, treating the management fee as an offset would understate the fair return determined by the Commission applicable to investor supplied capital.[242]

236 Exhibit 209.01, Utilities argument, paragraphs 205 and 205.
237 Exhibit 209.01, Utilities argument, paragraph 210.
238 Exhibit 209.01, Utilities argument, paragraph 206.
239 Exhibit 209.01, Utilities argument, paragraphs 211 to 213.
240 Exhibit 209.01, Utilities argument, paragraph 214.
241 Exhibit 209.01, Utilities argument, paragraph 215.
242 Exhibit 209.01, Utilities argument, paragraph 216.

363. The Utilities noted that in evidence they had stated that the adoption of a management fee would have a *de minimus* impact on credit metrics and financial risk and added that any improvement would be insufficient to warrant offset to ROE or capital structure.[243]

364. The Utilities stated that the suggestion that CIAC be awarded through an annual adjustment to the debt/equity ratio of individual utilities was not a reasonable alternative and submitted that the deemed common equity ratio should remain constant as it is intended to be a relatively permanent proportion of the investor supplied capital to be changed only when the circumstances of the utility change materially.[244]

365. Finally with respect to changes to investment policies or Rider I, the Utilities submitted that these changes, if they occur, might result in the amount of the management fee declining over time but would not change the fact that there are significant contributions now over which services are being provided for no compensation.[245] The Utilities added that policy amendment, although necessary to restrict growth in contributions, is not a solution by itself and that as long as there remain substantial contributions outstanding there remains a need for a management fee.[246] The Utilities also stated that the proposed Rider I might offer some mitigation to TFOs but would not address the contributions that are made to the distribution utilities or gas utilities.[247]

366. The UCA argued that, under cost-based regulation, utilities are entitled to recover their costs of providing service through rates, and if the Utilities could show that CIAC gives rise to utility or shareholder costs or risks as recognized by the legislation, it may be appropriate to allow them to recover those costs through a management fee or other mechanism. However, the UCA argued, the Utilities have not shown that there are costs associated with holding CIAC balances, and they have not provided any other reasonable basis on which to impose such a fee.[248]

367. The UCA submitted that Ms. McShane had advanced three basic arguments in support of a management fee in her evidence, which it summarized as follows:[249]

a) CIAC creates operating leverage that results in increased operating risk and an increase in the cost of equity for shareholders.

b) CIAC creates financial leverage that results in increased financial risk and an increase in the cost of equity for shareholders.

c) A management fee is appropriate as a matter of fairness in order to properly reflect the expectations of utilities and the value of the services that they provide.

### Operating leverage

368. The UCA submitted that, in principle, the argument that CIAC creates operating leverage that results in increased operating risk and an increase in the cost of equity for shareholders has

243 Exhibit 209.01, Utilities argument, paragraph 217.
244 Exhibit 209.01, Utilities argument, paragraph 219.
245 Exhibit 209.01, Utilities argument, paragraph 229.
246 Exhibit 209.01, Utilities argument, paragraph 226.
247 Exhibit 209.01, Utilities argument, paragraph 179.
248 Exhibit 210.02, UCA argument, paragraph 240.
249 Exhibit 210.02, UCA argument, paragraph 242.

some theoretical validity since CIAC can create incremental operational risk. However, the UCA submitted that in practice the numbers are very small, and in the actual circumstances of the Utilities the risk is *de minimus,* so any fee imposed to compensate for it would be trivial. Moreover, the UCA submitted that the Utilities already differ in the amount of operating leverage and risk that they bear without those differences ever having been recognized for rate making purposes, and there is no reason to recognize only risks associated with CIAC balances.[250]

369. The UCA submitted that the effect of CIAC is to magnify the effects of changes in operating costs, whether positive or negative, on the effective return. On an expected or probability-weighted basis, there is no impact on average shareholder returns, but in principle the variability of those earnings increases with CIAC. In principle, that increased earnings variability should increase the cost of equity slightly for the utility with assets financed with more CIAC. However, the UCA submitted that whether the reference point for the maximum shift caused by operating leverage is four or 40 basis points, it is still an extremely small effect. In response to examination by Commission Counsel, Mr. Marcus pointed out that the risk that is imposed by contributions is so small that it falls within the rounding error and the financial flexibility adjustments of all the witnesses who provided evidence in the proceeding.[251]

370. The UCA argued that the size of operating leverage effect illustrated in Table 2 of Ms. McShane's management fee evidence is a function of (a) the variability in operating costs, and (b) the size of the rate base on which a regulated return is earned. It has nothing to do with CIAC uniquely, but rather with the relationship between the variability of operating costs and the size of the rate base. The UCA submitted that, for all utilities, the size of the rate base is a function of numerous factors, only one of which may be CIAC. The UCA argued that the most obvious example of a non-CIAC determinant of rate base is accumulated depreciation.

371. Referencing Ms. McShane's Table 2, the UCA stated, if the label CIAC at the fourth line was instead relabelled "Accumulated Depreciation," then the first utility, being new, would have a rate base equal to gross plant, but the second utility, being several years older , would have recovered 20 per cent of its initial investment through depreciation charges. In that situation, all of the numbers shown in the table, and all of the effects of what is now labelled Accumulated Depreciation on the variability of earnings, are exactly that same as they were in the case where the second line was labelled CIAC. The UCA argued that it would not be reasonable to give the shareholders of the second utility a management fee just because they have recovered 20 per cent of their investment through depreciation charges, even though their position is no different from that of the shareholders of the second utility in Ms. McShane's table who recovered 20 per cent of the cost of the firm's facilities from contributing customers.[252]

372. The UCA submitted that, while in normal situations these types of differences in operating leverage exist all the time for different reasons, there are situations where operating leverage and the associated risk can become extreme, and where a management fee or equivalent mechanism may be reasonable. A clear example of that, the UCA submitted, is the High Island Offshore System (HIOS) case dealt with at the FERC. In that case, the HIOS regulated pipeline had had its rate base depreciated down to essentially nothing. In that situation, HIOS

250 Exhibit 210.02, UCA argument, paragraph 243.
251 Exhibit 210.02, UCA argument, paragraphs 249 and 250.
252 Exhibit 210.02, UCA argument, paragraphs 252 and 253.

shareholders have no money invested in the business, and earn no return or profit, but are still exposed to risk related to variability in operating costs and revenues.

373. The FERC confirmed in the specific circumstances unique to the HIOS case that its policy is to allow the pipeline to earn a management fee roughly equal to the standard rate of return applied to a deemed rate base equal to about five per cent of the pipeline's original investment or gross plant. The UCA submitted that is a management fee that is very small, and moreover only available when the utility has reached a point where its shareholders are earning essentially a zero return. The UCA argued that this is an extreme and unique situation that is completely unlike the situation facing any of the Alberta Utilities.[253]

374. The UCA stated that the FERC made itself very clear in the HIOS case that the decision does not stand for the principle supported by the Utilities here that utilities should get *both* a rate of return and a management fee, contrary to the implication of Ms. McShane's testimony.[254] In rebuttal evidence, the UCA stated:

> 165 The FERC decisions have nothing to do with returns on pieces of a company (i.e., the Utilities claim that contributed plant should be treated as separate from plant funded by investors). The FERC decisions provide a methodology that applies only when the rate base paradigm does not provide an adequate return for the operational risk because rate base is zero or extremely low for a given company or plant. This point is made extremely clear in the HIOS Order on Rehearing, where FERC stated:
>
>> On the other hand, however, a large investment in a new HIOS project, similar to the $80 million invested in the non-jurisdictional East Breaks Gathering System, would *terminate the management fee* in favor of a return to the traditional return on rate base methodology.[255] [emphasis added] [footnotes omitted]

375. Another factor to be considered, the UCA submitted, is that these types of risks or costs must have existed for years or decades, because the average CIAC levels have been consistent over a long period. Before the management fee issue was raised relatively recently in the ATCO Electric and AltaLink proceedings, none of the Utilities had identified any risk or cost associated with CIAC or complained that they were not being appropriately compensated for those risks and costs, the UCA argued. Whatever effects CIAC has on utility cost of equity must have been already accounted for by the Commission.[256]

376. The UCA submitted in its rebuttal evidence that Ms. McShane has made an implicit assumption that the Commission and its predecessors never thought about risks created by CIAC and therefore must grant an increase equal to the full amount of her recommendation. The UCA submitted that, if in fact the regulators granted a return commensurate with the utility's business risks in past cases, then granting an increase in this case due to risk associated with the full amount of contributions will compensate the utilities twice for the same risk.[257]

377. Further, the UCA stated that it is unreasonable to assume that the alleged risks of contributions were never considered by the Alberta regulator, unless one also reaches the

[253] Exhibit 210.02, UCA argument, paragraphs 255-257.
[254] Exhibit 210.02, UCA argument, paragraph 258.
[255] Exhibit 146.02, rebuttal evidence submitted on behalf of the UCA, paragraph 165.
[256] Exhibit 210.02, UCA argument, paragraph 265.
[257] Exhibit 146.02, rebuttal evidence submitted on behalf of the UCA, paragraph 168.

conclusion that utility rate of return witnesses in past cases over the last two decades – including Ms. McShane - did not conduct adequately thorough and complete risk assessments for their clients. The UCA argued that it appears that utility witnesses made almost no references to risks arising from contributions in past rate cases, even when certain Alberta utilities had as much as 35 per cent of their distribution property as CIAC in the 1990s and early 2000s.[258]

### Financial risk

378. With respect to the second argument (financial risk), the UCA stated that CIAC does not create any financial risk for shareholders and imposes no costs on them. Financial risk is therefore not a justification for imposing a management fee. Any financial risks or related shareholder costs associated with CIAC balances must have existed at essentially the existing or higher levels for many years, without the Utilities or the Commission ever pointing them out or recognizing them in rates.[259]

379. The UCA described the second argument as claiming that, because CIAC reduces the proportion of equity on which a return is earned relative to the total asset base, it leads to a lower equity ratio. Ms. McShane then analogized that reduction in equity as a proportion of the total asset base to the situation where a utility's financing of rate base includes debt, and the accepted principle that, when the debt ratio increases that increases financial risk, which in turn increases the cost of equity. The UCA submitted that Ms. McShane then characterized CIAC as debt-like and relied on the analogy with debt as the basis for her calculation of a proposed management fee. That calculation involves an after tax weighted average cost of capital (ATWACC) analysis in which she calculates a leverage adjustment that is supposed to reflect the increase in the cost of equity as the level of CIAC, and in her view the leverage or debt-like ratio increases, based on the premise that the ATWACC is constant.[260]

380. The UCA submitted that the difficulty with that argument is that CIAC does not resemble debt in any sense that is relevant to the concept of financial risk or the calculation of a leverage adjustment. The UCA further submitted that, with CIAC, there is no contractual interest obligation, and not even a principal repayment obligation. CIAC therefore creates no volatility in earnings and no financial risk, as that term is normally understood and explained in Appendix D to Ms. McShane's management fee evidence. It therefore does not increase the cost of equity for the firm, or impose any cost on shareholders.[261]

381. The UCA argued that, in her evidence, Ms. McShane provided no explanation of how CIAC increases the volatility of equity returns by creating financial risk, and that she provided no table or illustration analogous to her Table 2 to explain and demonstrate how CIAC creates financial risk that is distinct from the operational risk that Table 2 illustrates, for example using a hypothetical case where operating costs are constant.[262]

382. The UCA argued that the financial risk appears to be a risk that the Utilities have never noticed, even though they claim that they require an additional 40-100 basis points of equity return to compensate them for it, and that the lower equity ratio that Ms. McShane points to will arise, for example, through the accumulation of depreciation. Further, the UCA submitted that, if

258 Exhibit 146.02, rebuttal evidence submitted on behalf of the UCA, paragraph 169.
259 Exhibit 210.02, UCA argument, paragraph 244.
260 Exhibit 210.02, UCA argument, paragraphs 271 and 272.
261 Exhibit 210.02, UCA argument, paragraphs 273 and 276.
262 Exhibit 210.02, UCA argument, paragraph 277.

the financial risk argument falls, the entire logical underpinning of Ms. McShane's calculation of her proposed management fee must fall as well, since it is premised entirely on that argument.[263]

### Value of service

383. Lastly, the UCA argued that Ms. McShane's third argument is inconsistent with the legislation providing for cost-based ratemaking, the standard regulatory paradigm, and the fair return standard.[264]

384. The UCA stated that Ms. McShane's last argument is that it is not fair for the Utilities to be required to operate CIAC-financed facilities without earning a profit in connection with that activity, and that no rational competitive enterprise would operate expecting to recover only their expenses and earn a return on only a portion of the assets they use to provide services.[265]

385. As Mr. Marcus explained, the UCA argued, the argument that utilities are being deprived of a return is inconsistent with cost-based rate-making and the economic principles that underlie it. The entire theory on which the return on equity is set by regulatory agencies is that the required return on equity capital equals the (opportunity) cost of equity capital. As stated in Mr. Marcus' evidence:

> If the ROE equals the cost of equity, then it follows from elementary logic that investors should not care whether the utility invests the equity here, whether it invests the equity in a different project, or whether it passes money back to investors through dividends or share buybacks (or does not raise equity capital in the market) so the investors can invest capital elsewhere at a similar rate of return.[266] [footnotes omitted]

386. The UCA submitted that the evidence of Mr. Marcus explained why paying utilities a rate of return on capital that is never invested in the first place (through a management fee) provides skewed compensation for the utility. Mr Marcus stated in his evidence:

> Q. Please explain with reference to practical considerations why shareholders would be better off if they got an equity return on contributed property than if there were no contribution at all and shareholders simply invested equity in additional amounts of utility property?
>
> A. Giving the shareholders a rate of return when they do not have to make an investment is simply NOT equivalent to giving them a rate of return on an investment that they actually make.
>
> The Utilities' arguments focus on the asset side of the balance sheet (the contributed assets), but fail to recognize the liability side of the same balance sheet (that with contributed assets, they also require less debt and less shareholder equity).
>
> If the shareholders are paid a return as if they had invested equity in CIAC projects, but do not actually invest anything, they still have the money available for other valuable uses. Consider a project that a utility would have invested in, except it was required to collect CIAC instead. Two things happen:

263 Exhibit 210.02, UCA argument, paragraphs 279 and 281.
264 Exhibit 210.02, UCA argument, paragraph 245.
265 Exhibit 210.02, UCA argument, paragraph 282.
266 Exhibit 210.02, UCA argument, paragraph 285.

1. The utility does not receive a stream of earnings on the capital it would have invested in the new project. This is the sole focus of the Utilities' theory that equity investments are foregone when they invest in contributed property.

2. Because the utility has not invested its equity capital in projects paid for with CIAC, its equity capital is different than if it had invested in those resources in one or two ways:

   a) If the utility would otherwise not have enough equity to invest in new resources treated as CIAC, it would have had to raise that equity in the capital markets. In this case, it avoids having to raise equity in the capital markets.
   b) If the equity was available to it in the first place but not needed because of CIAC, the utility still has the equity available. The equity capital that is freed up because the investment was paid for using CIAC has a large number of other long-term uses ranging from buying back stock, paying more dividends, or making more investments (either regulated or unregulated).
   c) The utility could invest in the longer term in additional projects (e.g., capital maintenance) if it had more equity available. In such a case, the equity not invested in contributions may simply be invested in different projects, not "lost" even under the Utilities' theory.

To make decisions that consider the first factor (the asset side of the balance sheet) but do not consider differences in the availability of equity capital due to the CIAC (the liabilities and equity side of the same balance sheet) violates the principles of elementary finance, economics, and accounting and is, thus, extremely poor public policy. A decision to pay a full return on equity that is never invested in the first place, while still allowing the utility to invest the equity and earn a return (or alternatively never have to raise the capital at all) would give the shareholders far more money than if the utility had no contribution policy and simply invested the full amount in every project that was requested, regardless of cost. Therefore, paying shareholders an equity return without an equity investment clearly cannot be viewed as fair compensation, but is, instead, extremely skewed.[267]

387. With respect to the Utilities' fairness argument, the UCA submitted that Ms. McShane effectively acknowledged that her proposal is not consistent with the standard model of utility regulation, but said that it reflects a defect in the standard model, because the standard model does not fully reflect value in the way that competitive markets do.[268]

388. The UCA argued that this suggestion, in effect, is that there is something unfair or economically inappropriate with the concept of cost-based rate-making. The UCA cited Mr. Marcus' explanation that conventional utility regulation sets prices for utility service at a level that, in principle, allows the utility to recover exactly its costs, including the cost of equity capital or a fair return for shareholders. The UCA argued that there is nothing unfair or economically inappropriate about the model (cost-based rate-making) and that it is completely consistent with well-known economic principles.[269]

267 Exhibit 81.04, prepared testimony of William B. Marcus, pages 48 and 49.
268 Exhibit 210.02, UCA argument, paragraph 289.
269 Exhibit 210.02, UCA argument, paragraph 290, 291, and 294.

389. In reply argument, the UCA noted that the Utilities had simplified the management fee issue by abandoning the first two arguments (operating leverage/risk and financial leverage/risk) and relying entirely on the fairness or value of service argument. The UCA further stated that the Utilities made it clear that the proposed management fee is separate from, and in addition to, any compensation due to shareholders in respect of amounts invested or risks borne by shareholders and that in the context of arguing that the management fee should not be treated as an offset to allowed ROE, the Utilities emphasized that it is intended to compensate the utility for something different from, and in addition to, the cost of equity capital.[270]

390. The UCA argued that the Utilities' position is that the management fee has nothing to do with ensuring that shareholders earn a fair return, or that shareholders are adequately compensated for the risks that they face, because all of that is already accomplished through the Commission's ROE and capital structure determinations. It therefore apparently has nothing to do with compensating shareholders for any incremental CIAC-related operating risks of the kind acknowledged by Mr. Marcus, or with any "phantom financial risk" that CIAC imposes on shareholders.[271]

391. The UCA further submitted that, in order to approve the management fee proposal, the Commission must repudiate not simply a regulatory "policy," but the entire economic and logical basis for the cost-based rate-making approach that it has applied for decades.

392. The UCA stated that one of the arguments advanced by the Utilities is that no rational business would enter into or operate facilities if it did not expect to earn a profit on that activity. The Utilities referred to a variant of that argument, where they discussed Mr. Marcus's evidence in relation to the discounting of services as analogous to operating facilities at no profit. While that exchange involved a side issue, the point was that the analogy with the supposed behaviour of competitive businesses is not correct because the issue is whether a firm earns an appropriate profit on its entire business, not on individual parts of the business. Mr. Marcus gave the example of brushing activity by utilities, where the utilities do not expect to "earn a profit" on brushing, but it is something they have to do in order to earn a fair return on their investment in the overall business. If the shareholders earn a fair return on their investment, which they will do under the cost-based rate-making model in the absence of a management fee, then regardless of how that investment is deployed they have no complaint and there is no unfairness.[272]

393. In response to the question of whether the Utilities should receive a fee for management of contributed assets, the CCA submitted that both operations and maintenance expense amounts awarded and the current Commission approved methodology for the determination of rate of return adequately compensates for the management of Utilities' operational assets, including those financed by customers through CIAC.

394. In reply argument, the CCA submitted that it disagreed with the Utilities' argument that customers are providing zero compensation for CIAC assets. The CCA considered that customers are responsible for 100 per cent of the ownership costs of the CIAC assets and customers are paying for the management of the assets in the form of revenue requirement items. These items include any management, including board of director fees and expenses, insurance, and engineering expenses. The CCA stated that the value of services provided by the utility in

270 Exhibit 221.02, UCA reply argument, paragraphs 86, 90, and 91.
271 Exhibit 221.02, UCA reply argument, paragraph 92.
272 Exhibit 221.02, UCA reply argument, paragraph 104.

the management of CIAC assets are currently paid for by customers, and that by paying for assets up front in the form of CIAC customers are eliminating the risk to the utility holding the assets.[273]

395. The CCA also argued that the Utilities are compensated for invested capital, thus if there is no invested capital there should be no return. By having customers prepaying ownership costs in the form of CIAC, utilities should not be allowed to earn an excessive return. In particular, the CCA argued that a two per cent return is excessive, given the current interest rate and inflation rate environment. The two per cent equates to in excess of 50 per cent of current 30-year Government of Canada bond yields. The CCA argued that the Utilities are requesting 50 per cent of the risk free return and payment of all related operation and maintenance expenses, including management, engineering, insurance and board of director fees, for an asset they require customers to pay for up front.

396. The CCA submitted that a management fee should not be ruled on until Rider I effects are understood and could be forecast. The CCA argued that the Rider I will eliminate the need for a management fee, as CIAC levels will be reduced dramatically. The CCA also stated that it did not consider that a management fee should be implemented at the distribution level, noting that distribution utilities' CIAC levels are not comparable with transmission levels.

397. In responding to the question of whether the Utilities should be awarded a fee for management of contributed assets, IPCAA argued that there is no basis for a management fee of the nature applied for by the Utilities. Moreover, IPCAA submitted that adjustments to the ROE or the debt/equity ratio could only be justified if the management of property paid for by customers in some way increased utility risk, which, IPCAA argued, it does not.[274]

398. IPCAA reiterated the position set out in its evidence that with the AESO's proposed Rider I, there is no basis for a management fee, but stressed the fact that the Rider I proposal is not tied to the management fee proposal.

399. IPCAA noted that another concern with the proposed management fee is the potential double charging for DFO customers. If the TFOs are allowed to earn a management fee on TFO assets paid for by a customer contribution, IPCAA argued, then the DFO customers will be paying twice. First, they will pay a fee to the TFO for asset contributions from the DFO (that the DFO will pass through to its customers). Second, they will pay a return to the DFO for the AESO customer contribution in the DFO rate base for the TFO asset.[275]

400. CAPP argued that the management fee as proposed by Ms. McShane is unjustified and also excessive, and that CIAC should be treated as a deduction from rate base prior to calculating return and there should be no additional fee for management.[276]

401. In commenting on the justification for the award of a management fee, CAPP submitted that where the rate base is disappearing – the 'vanishing rate base' conundrum – there is an issue, as Mr. Marcus discussed, of providing the incentive to the company to continue to provide service and operate the system. Such situations are very rare and, CAPP submitted, the Utilities

273 Exhibit 218.01, CCA reply argument, paragraphs 22, 23, and 24.
274 Exhibit 212.01, IPCAA argument, paragraphs 23 and 24.
275 Exhibit 212.01, IPCAA argument, paragraph 29.
276 Exhibit 207.02, CAPP argument, paragraph 98.

requesting a management fee are instead in growth mode. CAPP argued that if utility investors had been harmed in taking CIAC all these years, the practice would never have developed and certainly would not have continued. CAPP submitted that, according to Ms. McShane, the Utilities have been undercompensated with returns that have been far too low on account of no allowance being made for the so-called "cost" to the utility investor from managing the assets bought with free money. If this were true, CAPP argued, one would expect to have seen some evidence of this in the marketplace. The Utilities should be selling at a discount because of this: yet they are not.[277]

402. The Utilities responded in reply argument to a number of the issues raised by interveners in response to the question of whether the Utilities should receive a management fee for contributed assets.

403. In response to the assertion that the Utilities are being fully compensated for the management of CIAC financed asset, the Utilities submitted that merely covering out of pocket costs is not compensation for the provision of value-added services.[278]

404. Noting that the principal basis for proposing the management fee was fairness, the Utilities submitted that while contributing factors such as increased operational risk and financial risk may appear minor in comparison, they are nevertheless valid. The Utilities noted that the UCA admitted the theoretically validity of the incremental operational risk and that attempts to trivialize those risks flatly ignore the $1.3-$2.5 billion of existing and forecast assets that the Utilities are now required to construct and operate on a wholly non-profit basis.[279]

405. The Utilities argued that the atypically high levels of CIAC in Alberta were not disputed by interveners. In response to intervener claims that the Utilities did not historically seem concerned about the size of CIAC or have not noticed the risk related to CIAC until recently, the Utilities stated that the issue was addressed in 2009 (ATCO Electric and AltaLink's GTA's) and that the electric distribution utilities have made concerted efforts to see changes made to investment policies.[280]

406. The Utilities stated that the UCA's purported analogies between CIAC and accumulated depreciation and vanishing rate base were misguided, and the Utilities also took exception to the fact that these positions were not advanced in evidence and could not be tested. Accordingly, the Utilities submitted that these positions should be accorded no weight by the Commission. In addressing these positions put forward by the UCA, the Utilities stated that the UCA's analogy between accumulated depreciation and CIAC is inapposite since no fee is sought to be recovered in respect of accumulated depreciation or amortized CIAC balances.

407. The vanishing rate base analogy, the Utilities submitted, fails to recognize that the FERC acknowledged that, in principle, compensation was due for valuable service rendered even where no investor-supplied capital was involved. While the FERC noted that the fee was wholly in lieu of a return on investor-supplied capital and not in addition to it, the Utilities submitted that it does not address the issue of CIAC, as the UCA acknowledged in Section 4.4 of their argument, wherein the UCA stated that it was not aware of any other jurisdiction that has approved a fee or

277 Exhibit 207.02, CAPP argument, paragraphs 107 and 111.
278 Exhibit 220.02, Utilities reply argument, paragraph 132.
279 Exhibit 220.02, Utilities reply argument, paragraph 133.
280 Exhibit 220.02, Utilities reply argument, paragraph 134.

other mechanism to compensate shareholders for the management of contributed assets.[281] The Utilities stated that where no rate base exists, the FERC approach may be appropriate and that, in this case, a substantial rate base composed of both investor and customer supplied capital does exist for which compensation is appropriate, though calculated differently for return on investor capital.[282]

408. The Utilities stated that the FERC cases, the RRO, water utilities and PPAs on depreciated power plants noted in the UCA's argument all support a management fee since they acknowledge that zero compensation for the value of services rendered does not result in just and reasonable rates.[283]

409. Noting that the UCA took issue with the analogy drawn between CIAC and debt, the Utilities argued that the accounting theory advanced by the UCA in its discussion appears to be new and untested evidence and should therefore be rejected by the Commission. Referring to specific sections of the UCA's argument, the Utilities argued that contrary to what the UCA stated in paragraph 275, interest is not the only thing which creates financial risk for shareholders; it ignores the principal repayment obligation. Further, contrary to paragraph 286, the Utilities are not solely focused on the asset side of the balance sheet. If there is an asset on the asset side, there must be something on the liability side. Since it is not equity, it must be a liability.

410. The Utilities stated that as a matter of principle, under IFRS, CIAC is accounted for as deferred revenue and therefore recorded as a liability on the balance sheet. The IFRS accounting entries are not driven by whether the regulator views the CIAC as debt or not. More importantly, debt rating agencies and other capital market participants do their analysis and form their opinions based on financial information prepared under IFRS. Title to the assets rests with the utilities and, under IFRS, are carried at cost without netting the related financing that is provided by customers. The Utilities argued that financing is not equity in the accounts of the utilities so it can only be debt. Under IFRS, the deferred revenue liability for CIAC is amortized or repaid over the lives of the CIAC assets.

411. For CIAC that is under Rider I, the utility would carry the assets at regulated NBV financed at the utility's approved capital structures. The Utilities argued that there is no physical difference and no difference in business risk between CIAC financed by customers and CIAC financed under Rider I.

412. Further, currently, if the AESO deems a CIAC funded asset to be part of the system, it can order the TFO to repay the customer contributed financing. The fact that the utility can be required to refund CIAC to customers when assets are deemed part of the system is confirmation, the Utilities argued, that the financing is repayable, like debt, on demand. In situations where repayment of CIAC occurs, the utility then finances the facilities with debt and equity. However, the nature of the services provided does not change; only the method of financing so, the Utilities argued, the compensation should not change either.

413. The Utilities also commented on the UCA's criticism of the management fee for being an alleged departure from cost-based, rate-base return methodology. The Utilities noted

281 Exhibit 210.02, UCA argument, paragraph 299.
282 Exhibit 220.02, Utilities reply argument, paragraph 135-136.
283 Exhibit 220.02, Utilities reply argument, paragraph 137.

inconsistency between the UCA's position and its' own expert's view of the return margin mixed model. The Utilities argued that UCA's apparent treatment of a "return" as a non-cost item also appears to be contradicted by the proper characterization of "return" as an economic cost by Mr. Marcus, and that a management fee is no different in this respect; it is calculated on CIAC balances extant at regular intervals and thus is as fully cost-based as the regular calculation of a fair return is on investor-supplied capital.

### 6.2.4 How would the provision of a management fee impact risk generally, and specifically for each utility, in 2011 and 2012?

414. In argument, the Utilities stated that the management fee would have no impact on risk generally, or specifically for each utility in 2011 and 2012 and would have no impact on business risk as business risks are the same with and without the fee. The Utilities also stated that the management fee would have a *de minimus* impact on financial risk since the fee as proposed has a very minor positive impact on credit metrics.[284]

415. The UCA, the CCA and IPCAA all submitted that the provision of a management fee would reduce the Utilities level of risk.[285]

416. The UCA submitted that the risk profile of the distribution Utilities would be reduced by more than that of the transmission utilities because the distribution utilities have a higher percentage of contributed property. Mr. Marcus estimated that a distribution utility similar to ATCO Electric or Fortis would see an effective increase of about 105 basis points in ROE under Ms. McShane's proposal, while a transmission Utility like AltaLink or ATCO Electric would have an effective increase of 32-42 basis points in ROE, assuming that no customers take Rider I. The municipal distribution utilities, with their slightly lower level of contributions identified in Mr. Marcus' direct testimony, would be intermediate between these entities. Dr. Roberts suggested that the improvement in risk profile would be relatively small at 40 basis points but would be larger at 100 basis points.[286]

417. The CCA stated that, if any management fee is awarded, this must then be offset by reductions in operations and management expense and rates of return. Management, engineering and other O&M expenses for CIAC related assets are already included in the revenue requirement for the management of the utilities operational assets including those financed by customers through CIAC. Awarding of a management fee would simply provide for excess returns and cash flow to the utility thereby reducing risk.[287]

418. In reply, the Utilities argued that an award of an ROE is not risk reduction, it is risk compensation. The Utilities reiterated their position that business risk would not change and that financial risk impacts would be *de minimus*.[288]

284 Exhibit 209.01, Utilities argument, paragraph 231 and 232.
285 Exhibit 210.02, UCA argument, paragraph 298; Exhibit 211.01, CCA argument, paragraph 62; Exhibit 212.01, IPCAA argument, paragraph 31.
286 Exhibit 210.02, UCA argument, paragraph 298.
287 Exhibit 211.01, CCA argument, paragraph 62.
288 Exhibit 220.02, Utilities reply argument, paragraph 144.

### 6.2.5 Have any other jurisdictions approved a fee or other mechanism to compensate shareholders for the management of contributed assets?

419. In the Utilities evidence, Ms. McShane made reference to a number of examples in which Alberta and other regulatory boards have adopted alternative approaches to compensation where the rate base/rate of return model did not provide adequate compensation. In argument, the Utilities stated that these examples were different but nevertheless support the notion that a utility is entitled to fair compensation for valuable services rendered.[289]

420. The UCA, the CCA and IPCAA all stated that they were not aware of any other jurisdiction that has approved a fee or other mechanism to compensate shareholders for the management of contributed assets.[290]

421. In its reply argument, the UCA noted the examples cited by the Utilities where regulators have awarded management fees or margin returns to regulated entities and thereby departed from the conventional cost-based rate-making construct. The UCA submitted that none of those examples is inconsistent with the UCA's position, in that all of them involve situations where a regulated entity finds itself with a rate base that is very small relative to its operating expenses, and where shareholders accordingly face operating risks that are large relative to their regulated earnings. The UCA argued that in those cases the margin return was awarded in place of a conventional rate base/rate of return profit, and not in addition to it.[291]

422. IPCAA stated that it was unaware of any evidence on the record suggesting that anything like the proposed management fee has been approved in any other jurisdiction and that a fee of the nature requested by the Utilities would appear to have no support from practices in other jurisdictions in Canada and the United States. However, IPCAA pointed out that numerous jurisdictions have adopted practices similar to the AESO's Rider I proposal and provided the examples of jurisdictions that have adopted Rider I-like approaches.

423. In its reply argument, IPCAA noted the references by the Utilities to cases where the rate base/rate of return model did not provide adequate compensation. These anecdotal references, IPCAA submitted, include Alberta-based examples such as the regulated rate tariffs of the distribution companies which are supported by special legislation. IPCAA argued that the Utilities, with the resources of eleven utility participants and an expert from Foster Associates Inc. could not produce a single example of an approved management fee for CIAC-financed assets.[292]

424. In response to IPCAA's argument, the Utilities stated that IPCAA's alleged Rider I "precedents" beg the issue that the management fee is trying to resolve and that Rider I was irrelevant to the management fee issue. The Utilities also argued that the very existence of those Rider I precedents is tacit recognition of the inherent unfairness to the Utilities for the not-for-profit turnkey construction and operation service they are obliged to provide. Finally, the Utilities noted that Rider I did not apply to gas utilities or electric distribution utilities.[293]

289 Exhibit 209.01, Utilities argument, paragraph 233.
290 Exhibit 210.02, UCA argument, paragraph 299; Exhibit 203.01, CCA response to AUC Additional Questions, Q2; Exhibit 212.01, IPCAA argument, paragraph 32.
291 Exhibit 221.02, UCA reply argument, paragraph 107.
292 Exhibit 222.01, IPCAA reply argument, paragraph 21.
293 Exhibit 220.02, Utilities reply argument, paragraphs 145-147.

### 6.2.6 If a management fee is awarded, who should pay the management fee?

425. The Utilities stated that the management fee should be recovered from the same customers who now pay for the operating and maintenance costs respecting CIAC funded assets. The Utilities noted that all operating costs for CIAC financed facilities are recovered from all existing customers without distinction amongst customer classes. Finally the Utilities stated that there is no need for consideration of this matter as part of a Phase II proceeding and the recovery of the fee as proposed is a straightforward matter and no further process should be directed with respect to allocations.[294]

426. The UCA and the CCA both submitted that no management fee on contributed assets was warranted. However, the UCA submitted, should a management fee be awarded, to the extent possible, any management fees adopted should be assigned directly to customers who make the contributions. The CCA shared the UCA's opinion on this issue.[295]

427. The UCA submitted that a fee on a TFO contribution assigned to the DFO (if allowed) should be paid by all DFO ratepayers, in the same proportion as the underlying DFO rate base for property contributed to the TFO. As a practical matter, however, the UCA argued that it is difficult to see how such a scheme could be feasible at the distributor level in relation to individual customers, especially small-volume customers. For distribution contributions, which are often for relatively small projects (such as underground line extensions to subdivisions), the UCA does not consider it practical to charge individual customers. The UCA argued that the amounts could be allocated to customer classes in Phase II cases in proportion to the allocation of contributions to customer classes that is made in order to calculate the appropriate allocation of return and taxes based on total rate base.[296]

428. The CCA stated that, if Rider I was approved and if, contrary to the CCA's recommendation, a management fee were approved, all distributors who are presently required to make contributions to the TFOs for TFO investments in distribution assets exceeding the AESO's maximum investment levels should be required to adopt Rider I. This will ensure there is no double counting; first, as a result of the distributor earning a return on the amount of the contribution and second as a result of the TFO earning a management fee on the same assets.[297]

429. IPCAA argued for resolution of the underlying problem that has caused the TFOs to pursue a management fee; namely, increased customer contributions by reason of, (a) the significant increases in TFO capital costs, and (b), the lagging of the AESO's investment levels. IPCAA submitted that implementation of Rider I will contribute to resolving this underlying problem.[298] IPCAA further submitted that, should the Commission choose to approve a management fee, the determination of which customers should pay a fee of the nature of the management fee proposed by the Utilities is a Phase II general tariff application matter and should not be determined in this proceeding.[299]

294 Exhibit 209.01, Utilities argument, paragraph 236, 237 and 239.
295 Exhibit 210.02, UCA argument, paragraph 302; Exhibit 203.01, CCA response to AUC Additional Questions, Q3.
296 Exhibit 210.02, UCA argument, paragraphs 302 and 303.
297 Exhibit 203.01, CCA response to AUC Additional Questions, Q3.
298 Exhibit 212.01, IPCAA argument, paragraph 33.
299 Exhibit 212.01, IPCAA argument, paragraph 34.

430. IPCAA also noted that the Commission's question; namely, "should *only specific* rate payers pay the management fee on the assumption that the party who causes a cost to be incurred or who benefits from the cost incurred should pay" helps to highlight the absurdity of the Utilities' management fee proposal. If one were to point an accusing finger at the group of customers it might be claimed "caused" the so-called "need" for a management fee, the one group that might be singled out is the group of customers paying for the customer contributed assets. But how exactly could it be claimed that these customers caused this cost? They have already done everything and more that could reasonably be demanded of any customer – in this case, of course, paying the full costs of the facilities. Moreover, IPCAA argued, the amount of the cost is not something these customers necessarily have any control over.[300]

431. IPCAA submitted in reply argument that the Utilities apparently seek a decision that would prospectively deny basic intervener rights in Phase II proceedings to challenge matters such as cost causation and cost allocations. While debating the allocation of the management fee in Phase II proceedings will be an administrative burden, denying the right to be heard on this issue is not appropriate. A better solution is to deny the management fee for the reasons stated earlier in IPCAA's argument and reply.[301]

432. In reply argument, the Utilities stated that the fact that regulators have directed that the O&M relating to the operation of CIAC-funded assets should be recovered from all system users fully supports the position advanced by the Utilities in argument.[302]

### 6.2.7 What is the minimum amount of contributions in aid of construction that should warrant a management fee?

433. In argument, the Utilities stated that, while the proposed management fee could be applied to all contributions, their recommendation was to limit the application of the 2 per cent return to CIAC balances in excess of 4 per cent gross approved rate base (inclusive of contributions) in order to appropriately recognize the fact that other utilities in Canada also have some CIAC, albeit generally in smaller proportions.[303]

434. The UCA and the CCA did not believe that any amount or level of CIAC should warrant a management fee.[304]

435. IPCAA re-affirmed its previous submissions that the proposed management fee cannot be awarded under the *Electric Utilities Act*. IPCAA stated that should the Commission consider that it has the jurisdiction to award a fee of the nature proposed by the Utilities and that such a fee should be awarded, IPCAA recommends that the Commission use a bright line test of 10 per cent for determining if a management fee is required for the TFOs, as has been previously suggested by AltaLink Management Ltd. The bright line should be calculated by dividing the unrecovered CIAC by the total rate base of each utility.[305] IPCAA submitted that it did not agree with the Utilities four per cent bright line test for the following reasons:

300 Exhibit 212.01, IPCAA argument, paragraph 37.
301 Exhibit 222.01, IPCAA reply argument, paragraph 28.
302 Exhibit 220.02, Utilities reply argument, paragraph 148.
303 Exhibit 209.01, Utilities argument, paragraph 240.
304 Exhibit 210.02, UCA argument, paragraph 304, Exhibit 211.01, CCA argument, paragraph 65.
305 Exhibit 212.01, IPCAA argument, paragraphs 41 and 42.

a) A 4% bright line test contradicts the evidence of AltaLink's own witness from a prior proceeding that stated that going beyond a 10% bright line was not going to be within "a likely reasonable range", implying that less than 10% was within a likely reasonable range.

b) Even noting that the Utilities Table 1 includes a very short list of allegedly comparable utilities, the proposed 4% bright line test is well below that of FortisBC (8.8%) and Terasen Gas (6.3%) and somewhat below Maritime Electric (4.5%). A bright line used to justify an exceptionally unusual payment such as a management fee should be a boundary condition, not a median or some type of average. Clearly, FortisBC, Terasen and Maritime Electric do not receive a management fee and therefore the Utilities have a very weak argument for any harm at a bright line test below 10%.

c) The average historical CIAC as a percentage of gross rate base for the Utilities for the period 2007 to 2010 has been 8.5%. This level is still below the FortisBC level of 8.8%, further suggesting that nothing below 10% should be seen as an appropriate "bright line" for the determination of a management fee.[306] [footnotes omitted]

436. In reply argument, the Utilities submitted that the 10 per cent cut off proposed by IPCAA received no attention at the hearing and no weight should be given to IPCAA's argument in that regard. Further, the Utilities stated that, in suggesting that Dr. Cicchetti called for a 10 per cent threshold, IPCAA has seriously mischaracterized that evidence. The Utilities also stated that the current management fee proposal is made on the basis of Ms. McShane's evidence and not evidence filed in another proceeding.[307]

### 6.2.8 What method or formula should the Commission adopt to calculate a management fee if it chooses to award one?

437. The Utilities acknowledged that while there are likely a number of approaches that could be used to estimate a level of compensation for CIAC that would simultaneously recognize the value of services provided and the risks assumed by the Utilities, the approach advanced by Ms. McShane is the best option available. The Utilities noted that no other proposals were filed in evidence nor otherwise detailed and examined on the record of this proceeding.[308]

438. The Utilities stated that the selected methodology met Ms. McShane's objectives of constructing an approach: (1) that had a basis in financial theory, (2) the outcome of which could be objectively determined, (3) which could be applied consistently across all the Alberta Utilities, and (4) that was supported by regulatory precedent.[309]

439. The Utilities submitted that Ms. McShane presented what are really two approaches which proceed from different premises but yield the same quantum of compensation. The first proceeds on the premise that CIAC represents a liability akin to debt, which decreases the effective equity ratio of the Utilities. In the absence of CIAC, the assets would be financed with interest bearing debt. The amount of compensation that is reasonable for CIAC funded assets is derived from the increase in the cost of equity that results from the reduction in the Utilities'

306 Exhibit 212.01, IPCAA argument, paragraph 46.
307 Exhibit 220.02, Utilities reply argument, paragraph 150, 151.
308 Exhibit 209.01, Utilities argument, paragraph 244.
309 Exhibit 209.01, Utilities argument, paragraph 245.

effective equity ratio due to the presence of debt-like CIAC. The amount of CIAC compensation is equivalent to the return required for bearing incremental financial risk.

440. The Utilities noted that Ms. McShane explained that the same estimate of a reasonable margin is arrived at without invoking financial risk by applying the "OEB Methodology" under which it is assumed that, in the absence of CIAC, the utilities financed all of their assets at the same overall return (their opportunity cost of capital). To recognize that ratepayers are providing an interest-free loan to the Utilities, ratepayers are credited with the utility market cost of debt. The effective compensation to the utilities for CIAC is limited to the difference between their overall cost of capital and their cost of debt.[310]

441. While alternatives such as a return margin were considered by Ms. McShane, the Utilities submitted that the selected methodology was chosen because it could be easily applied generically across utilities and it appropriately focused on the assets and resulted in a sharing of benefits of the CIAC among customers and utilities.[311]

442. In response to Mr. Marcus' criticism of the quantum of the proposed management fee[312] as disproportionate to the impact on operating leverage and additional risk posed by CIAC, the Utilities stated that examining the impact on operating leverage alone does not suffice. It is not a benchmark for reasonableness or fairness of the proposed fee. The Utilities noted that the Utilities are exposed to operational, regulatory and market risks with respect to CIAC financed assets and that these risks are not easily quantifiable.

443. Further, the Utilities submitted that the proper context for the evaluation of the reasonableness of a management fee is not solely the risks borne with respect to the CIAC-funded assets, but also fairness in light of the value of service provided.

444. In response to parties'[313] submissions that a small percentage addition to O&M expense could be employed as a management fee, the Utilities stated that such an approach should be rejected and that any suggestion that what is being managed for contributed property is limited to operating and maintenance expense misrepresents and marginalizes the functions that the Utilities perform in relation to CIAC-financed assets.[314]

445. The UCA opposed the imposition of a management fee in any form and had no opinion on what formula should be applied or collection method adopted.[315]

446. The CCA submitted that, while it did not support any management fee on contributed assets, the concept put forward by the Utilities is that it is required to compensate the utility for planning, managing and operating the contributed assets. Accordingly, the management fee, if approved, should be determined as a per cent of the O&M expenses associated with contributed assets. The CCA further submitted that the determination as to whether a management fee

310 Exhibit 209.01, Utilities argument paragraph 246.
311 Exhibit 209.01, Utilities argument, paragraph 248.
312 Transcript, Volume 6, page 815, lines 15-23.
313 Exhibit 130.01, Mr. Marcus' response to Utilities-UCA-58(c)), Exhibit 202.01, IPCAA response to AUC Additional Questions, Q4; Exhibit 203.01, CCA response to AUC Additional Questions, Q4.
314 Exhibit 209.01, Utilities argument, paragraph 254.
315 Exhibit 210.02, UCA argument, paragraph 305.

applies or not should be made at the time of the GRA, on a forecast basis, having regard to a threshold.[316]

447. IPCAA stated that, if a management fee were to be approved, any fee should only be calculated on any amounts that exceed the 10 per cent bright line test. Furthermore, it should be calculated on the basis of the service of managing property and should not be based on the value of the property itself.[317] IPCAA further stated that the idea that the Utilities are providing the service of managing the CIAC assets without compensation is wrong. Any cost incurred is compensable and is compensated for as is any reasonable and prudent cost.[318]

### 6.2.9 Should other forms of no-cost capital also be eligible for a management fee? What is the rationale for including or excluding other forms of no-cost capital?

448. The Utilities submitted that the management fee proposal was to apply only to CIAC and that other forms of no-cost capital would not be eligible for, or included in, the calculation of the management fee. The Utilities noted that there is a distinction to be made between CIAC and other forms of no cost capital. CIAC balances, the Utilities argued, relate to long-term assets over which the Utilities provide valuable services and bear risks. Other forms of no cost capital arise as a result of timing differences between the incurrence and recovery of costs and do not involve the fairness issue related to CIAC financed assets and, consequently, do not warrant treatment analogous to that requested for CIAC.[319]

449. In reply argument, the Utilities added that the management fee was based in part on the business risks inherent in offering a not-for-profit turnkey construction service and not-for-profit operations and maintenance service and that these services were very different from the business risks associated with managing deferred taxes and depreciation reserves.[320]

450. The UCA submitted that it did not accept the premise that a management fee is appropriate or necessary as compensation related to the management of CIAC or any other form of no-cost capital, or accumulated depreciation. Any proposal to give shareholders a return on amounts that they have not actually invested in the business is misconceived and inconsistent with the principles of cost-based rate-making.[321]

451. The CCA considered that no management fee should be allowed on no-cost capital. The CCA considered that the fair return and revenue requirement awards have, and do, take into account issues surrounding no-cost capital. Customers currently pay all costs associated with no-cost capital including asset management. The CCA views no-cost capital as reducing utility risk, not increasing risk.[322]

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316 Exhibit 203, AUC-CCA-04.
317 Exhibit 212.01, IPCAA argument, paragraph 47.
318 Exhibit 212.01, IPCAA argument, paragraph 49.
319 Exhibit 209.01, Utilities argument, paragraphs 257 and 258.
320 Exhibit 220.02, Utilities reply argument, paragraph 156.
321 Exhibit 210.02, UCA argument, paragraph 306.
322 Exhibit 211.01, CCA argument, paragraph 67.

452. IPCAA submitted that, as it had previously discussed, the Commission does not have the power to award compensation for costs for which no utility investment has been made over and above what is needed to reimburse the utility for its reasonably incurred costs.[323]

**6.2.10** Assuming that the balance of CIAC changes on an annual basis, what method or formula should the Commission adopt to calculate a management fee and include the fee in base rates, it if chooses to award one? When should a management fee be instituted if it is approved?

453. The Utilities summarized the calculation of the annual management fee in their argument, as follows:

> The annual Management Fee should be calculated by (1) summing the mid-year approved CIAC balance and rate base net of other forms of no cost capital (i.e. mid-year pro-rated invested capital); (2) calculating 4% of the total; and (3) subtracting the 4% from the forecast test-year CIAC balance. The resulting balance equals the CIAC eligible for Management Fee. The management Fee in dollars for each of the Alberta Utilites would then be calculated by applying the requested 2% to the eligible CIAC balance. For the taxable utilities, the resulting Management Fee would then be grossed up by the test year corporate income tax rate.[324]

454. The Utilities noted that, if the Commission approves Rider I, the annual amount of CIAC eligible for the management fee would be dependent on the extent to which customers opt for Rider I, which is uncertain. Consequently, the Utilities recommended the implementation of a deferral account for the TFOs which would true up the difference between the actual and forecast management fee.[325]

455. For those utilities who are, or will be, subject to PBR, the Utilities recommended the calculation of the annual management fee described above be modified to use the previous year actual mid-year balances as, for other than the PBR base year, there may not be an approved forecast mid-year rate base balance.[326] The Utilities submitted that the management fee should be approved to be effective January 1, 2011.[327]

456. The UCA's position was that no management fee is warranted, and so it did not offer an opinion on how the Commission should calculate a fee that the UCA does not believe should be imposed in any form or in any amount.[328]

323 Exhibit 212.01, IPCAA argument, paragraph 54.
324 Exhibit 209.01, Utilities argument, paragraph 260.
325 Exhibit 209.01, Utilities argument, paragraph 261.
326 Exhibit 209.01, Utilities argument, paragraphs 262 and 263.
327 Exhibit 209.01, Utilities argument, paragraph 264.
328 Exhibit 210.02, UCA argument, paragraph 309.

457. IPCAA submitted that, should the Commission approve a management fee against IPCAA's recommendations, IPCAA submits that the management fee should be:

a) Calculated only on any amounts that exceed the 10% bright line test; and

b) Calculated on the basis of the service of managing property and should not be based on the value of the property itself.[329]

458. In reply argument, IPCAA reiterated its submission that the Commission is without jurisdiction under the *Electric Utilities Act* to award a management fee as requested by the Utilities. Further, IPCAA submitted that, should the Commission conclude that it does have jurisdiction to award some form of fee for management services as requested by the Utilities, and that such a fee is warranted, IPCAA submits that it should only be instituted after completion of a Phase II proceeding of the AESO or relevant DFO.[330]

459. In its reply argument, the Utilities stated that it would be grossly unfair to the Utilities to deny the recovery of the management fee now because the uptake on Rider I may not be known for some months after a decision is released.[331]

## 6.3 Commission findings

### Jurisdiction to award a management fee

460. The Commission has the obligation to ensure that the rates it establishes are just and reasonable in accordance with Section 121(2)(a) of the *Electric Utilities Act*, Section 36(a) of the *Gas Utilities Act* and Section 89(a) of the *Public Utilities Act*.

461. In fixing just and reasonable rates, the *Gas Utilities Act* (Section 37) and the *Public Utilities Act* (Section 90) require that the Commission determine a rate base on which to fix a fair return by giving due consideration to the cost of the property when first devoted to public use and to the prudent acquisition cost to the owner of the utility, and to necessary working capital. In the *Electric Utilities Act*, return is considered to be a subset of the "costs and expenses associated with capital *related to the owner's investment in the electric utility*" (Section 122(1)(a)) and is specified as a fair return on the equity of shareholders of the electric utility as it relates to the investment (Section 122(1)(a)(iv)).

462. The process by which the Commission sets rates was described by the Supreme Court in *Northwestern Utilities Ltd. v. City of Edmonton*[332] and cited in *Stores Block*:

> The PUB approves or fixes utility rates which are estimated to cover expenses plus yield the utility a fair return or profit. This function is generally performed in two phases. In Phase I the PUB determines the rate base, that is the amount of money which has been invested by the company in the property, plant and equipment plus an allowance for necessary working capital all of which must be determined as being necessary to provide the utility service. The revenue required to pay all reasonable operating expenses plus provide a fair return to the utility on its rate base is also

329 Exhibit 212.01, IPCAA argument, paragraph 55.

330 Exhibit 222.01, IPCAA reply argument, paragraph 34.

331 Exhibit 220.02, Utilities reply argument, paragraph 158.

332 *Northwestern Utilities Ltd. v. City of Edmonton*, [1979] 1 S.C.R. 684 at page 691; *Stores Block, supra*, paragraph 65.

determined in Phase I. The total of the operating expenses plus the return is called the revenue requirement. In Phase II rates are set, which, under normal temperature conditions are expected to produce the estimates of "forecast revenue requirement". These rates will remain in effect until changed as the result of a further application or complaint or the Board's initiative. Also in Phase II existing interim rates may be confirmed or reduced and if reduced a refund is ordered. [emphasis added]

463. This approach to approving the recovery of a utility's prudent costs and awarding a fair return on the equity portion of a utility's investment is the basis of the cost of service regulation framework that has been employed by the Commission for decades.

464. The legislature has recognized that there are situations where return on rate base may be inadequate to allow for proper compensation. Section 6(1)(b)(i) of the *Regulated Rate Option Regulation*[333] promulgated under the *Electric Utilities Act* requires the Commission to approve a reasonable return (which is not tied to investment but rather to the obligation to provide service) as well as a risk margin (Section 5) that compensates for a number of specific risks.[334] Neither the *Electric Utilities Act* nor the *Gas Utilities Act* contain such provisions.

465. Interveners generally argued that the relevant legislation and cost of service regulation principles provide for the entire compensation scheme for the Utilities, which consists only of a return on the capital invested in rate base and the recovery of prudent costs. The interveners characterized the management fee as a request for additional return or profit, which they argued the Commission was not authorized to grant under a strict interpretation of the statutes together with traditional cost of service regulatory principles.

466. In general, the Commission agrees with this interpretation of the statutes. However, the Commission considers there are circumstances, such as the "vanishing rate base" scenario cited by some interveners, where the return on rate base approach may not allow for sufficient return to provide for just and reasonable rates. In such situations, the Commission considers that case law provides it with the authority to implement a mechanism, which might be in the form of a management fee, in order to ensure that just and reasonable rates are achieved.

467. As noted above, the Utilities cited the Supreme Court of Canada's decision in *Northwestern 1961* in support of their *quantum meruit* argument. In that case, the Supreme Court of Canada found that the Commission's predecessor had jurisdiction to fix just and reasonable rates, which included fixing rates to allow for transitional losses between the date of application and the date of decision. The Court concluded that, even in the absence of any statutory provision, there is an obligation at common law for ratepayers to pay for utility service on the basis of *quantum meruit* as part of the jurisdiction to ensure that tolls are at all times just and reasonable.

468. In *Northwestern 1961*, the authority of the Commission's predecessor to establish a "purchased gas adjustment clause" was at issue. This clause was essentially a variance account mechanism that permitted the utility to recover from consumers in the future amounts the utility had to pay for gas that proved more expensive than the utility's estimates (and to refund amounts

333 AR 262/2005.

334 Similarly, Section 5(a) of the *Default Gas Supply Regulation,* AR 184/2003 under the *Gas Utilities Act* provides for "...a reasonable return on costs deemed eligible by the Commission, excluding the cost of gas that is provided and delivered..."

to consumers if the estimates proved to be greater than the actual cost). While not specifically provided for in the relevant statutes, the jurisdiction of the Commission's predecessor to approve such a mechanism was upheld by the Court. In particular, at pages 406-407 of its judgment, the Court stated that the authority flowed from the power to set just and reasonable rates which would yield a fair return:

> With great respect, however, the proposed order would be made in an attempt to ensure that the utility should from year to year be enabled to realize, as nearly as may be, the fair return mentioned in that subsection and to comply with the Board's duty to permit this to be done. How this should be accomplished, when the prospective outlay for gas purchases was impossible to determine in advance with reasonable certainty, was an administrative matter for the Board to determine, in my opinion. This, it would appear, it proposed to do in a practical manner which would, in its judgment, be fair alike to the utility and the consumer.
>
> As pointed out by Porter J.A., s. 67(5) does not touch the matter and this the respondent concedes, but the Board has not assumed to act under that subsection. Rather did it propose to make the order under the powers given to it and the duty imposed upon it by the sections to which I have referred to fix just and reasonable rates which would yield the fair return mentioned in s. 67(2). [emphasis added]

469. The Commission considers that this case supports the proposition that, in certain circumstances, in order to satisfy its duty to set just and reasonable rates, the Commission has the jurisdiction to approve compensatory schemes that are not specifically provided for in the statutes to ensure that a fair return is realized.

470. The Commission will now consider the questions as to whether: (1) the rate of return compensation scheme set out in the legislation is insufficient to provide for just and reasonable rates given the current levels of CIAC, and (2) if so, whether the proposed management fee is warranted.

471. It should be noted that this was not the manner in which the Utilities framed their argument in support of the management fee. The Utilities' primary argument was that the principle of *quantum meruit* requires that the services that the Utilities are providing with respect to the CIAC-financed assets be compensated. The Utilities also justified the management fee by submitted evidence related to increased risk (financial, operating leverage and business risk).

472. Therefore, with respect to the first question, the Commission will consider whether the arguments of the Utilities with respect to *quantum meruit* and increased risk associated with CIAC support the conclusion that the rate of return compensation scheme is insufficient.

### Is the rate of return compensation scheme set out in the legislation insufficient to provide for just and reasonable rates?

473. As discussed above, the *Electric Utilities Act* and the *Gas Utilities Act* provide for compensation consisting of a return on utility investment and recovery of prudent costs. The Utilities submitted that where CIAC levels approximate the industry average, the conventional model generally provides fair and reasonable compensation. However, the Utilities argued that CIAC levels are significantly higher in Alberta than the industry average and, as a result, "that paradigm does not provide fair or any compensation in relation to services provided and risks

borne in relation to CIAC-funded assets."[335] The Utilities stated that the proposed management fee will augment the conventional model, and also stated that the proposed management fee provides for a margin or fair compensation for all of the services they render relating to assets that are constructed, owned and operated by the Utilities, but which are financed by customers.

474. Interveners argued that the statutory and regulatory schemes do provide for sufficient compensation. The UCA submitted that the cost-based rate-making principle says that utilities should be entitled to charge rates that provide them with a reasonable opportunity to recover their prudently incurred costs, including a fair return on the capital they have invested in the business, but that they are not entitled to charge rates that are higher than that. The UCA argued that approval of the management fee proposal would result in profits or returns to shareholders that exceed the cost of equity capital and the levels dictated by the fair return standard, and it would result in rates that are not just and reasonable.[336]

475. In determining whether rates are not just and reasonable without specific compensation for services the Utilities provide in respect of the CIAC-funded assets, given the current levels of CIAC, the Commission will now address the main arguments cited by the Utilities namely:

- *quantum meruit* for value of services rendered
- risk considerations

### Value-added services and the concept of *quantum meruit*

476. The Utilities submitted that the services for which they are requesting compensation by way of a management fee include the construction, operation and maintenance of CIAC funded assets. While the interveners argued that the Utilities are being fully compensated for the provision of services, the Utilities replied that merely covering out-of-pocket costs is not compensation for the provision of value-added services.[337]

477. The Utilities appear to suggest that the concept of *quantum meruit* provides both the jurisdiction and the requirement that they be compensated above cost for these services, which they have also referred to as the "value-added" services. Thus, the Commission considers that determining the value of the services provided by the Utilities in respect of the CIAC-funded assets is fundamental to assessing the Utilities' *quantum meruit* argument.

478. The Commission finds that the Utilities have not established that they are providing any "value-added" services specifically associated with CIAC-funded assets. The Utilities argued that the construction, operation and maintenance of CIAC-funded assets is a value added service. The Commission does not agree. The construction, operation and maintenance of the assets owned by the utility are necessary for the provision of electric utility service, whether the assets were funded by CIAC or not. The Utilities have proffered no evidence of having to provide any services beyond the delivery of the electric utility service that is required, pursuant to their obligation to serve, and for which they are compensated through the rates approved by the Commission.

[335] Exhibit 220.02, Utilities reply argument, paragraph 111.
[336] Exhibit 221.02, UCA reply argument, paragraph 100.
[337] Exhibit 220.02, Utilities reply argument, paragraph 132.

479. Further, the Commission considers that the Utilities have not provided any evidence by which the Commission can quantify these "value-added" services, over and above the costs incurred for the provision of electric utility service, for which they are compensated through the rates approved by the Commission.

480. The Utilities cited *Northwestern 1961* in support of the *quantum meruit* nature of their claim. However, the Commission finds that the Utilities are unable to specifically quantify the actual cost of the "value added" services, other than to say that reasonable compensation can be derived from "the increase in the cost of equity that results from the reduction in the utilities' effective equity ratio due to the presence of debt-like CIAC."[338] In contrast, in *Northwestern 1961*, the transitional amounts that the Commission's predecessor determined the utility should be compensated for were clearly identifiable and quantifiable amounts incurred by the utility. This is in distinct contrast to the Utilities' request for compensation.

481. Nonetheless, the Utilities' proposal that the management fee should be equivalent to the increase in the cost of equity that results from the reduction in the Utilities' effective equity ratio due to the presence of debt-like CIAC appears to argue that the Utilities incur an opportunity cost by being required to construct, operate and maintain CIAC funded assets. However, the Utilities recover the prudently incurred costs to construct, operate and maintain the CIAC funded assets as well as an allowed return on the working capital required to fund these costs through the rates approved by the Commission. Consequently, the Commission does not agree that the Utilities incur an opportunity cost in being required to fund the construction, operation and maintenance of the CIAC funded assets.

482. On a final note, when one looks at the contributed capital scheme and the notion that customers must contribute some portion of the initial start up costs, one must also consider what benefit the utility receives. If it was not for the customer's contribution, the utility would not have that customer nor the opportunity to invest in the rate base assets not funded by CIAC that are required to provide service to that customer.

483. The Commission finds that it has not been established that the services provided by the Utilities in respect of CIAC-funded assets represent a value added service that is in addition to the utility services which are compensated under the statutory scheme. Nor has it been established that the services have any quantifiable value. Accordingly, the Commission finds that there is no evidence that the provision of services in respect of CIAC-funded assets requires any compensation through a management fee or results in rates that are not just and reasonable.

### Risk considerations

484. The Commission will now address the question of whether the Utilities rates are just and reasonable considering the argument that the Utilities incur risks related to CIAC for which they are not adequately compensated.

485. The Utilities argued that (1) the higher the level of CIAC relative to the total rate base, the higher is the operating leverage; and (2) the higher the level of CIAC relative to total capital (inclusive of CIAC), the higher is the financial risk.[339] The Utilities stated that operating leverage

338 Exhibit 86.01, opinion on management fee and Rider I, lines 48-51.
339 Exhibit 86.01, page 13, lines 361-364.

refers to the sensitivity of the earned return on rate base to unanticipated changes in revenues and/or costs.[340]

486. The Utilities also stated that, as set out in CCA-Utilities-31, there are business risks and liabilities other than the operating leverage risk to which the Utilities are exposed. The Utilities listed these business risks as:[341]

- Operational risk (liabilities for):
  i. Damages to company facilities by others or weather
  ii. Public injury as a direct result of company operations
  iii. Environmental contamination resulting from a release of contaminates
  iv. Release of natural gas causing fire or explosion as a direct result of company operations
  v. Service outages which result in customer property damages and/or injury as a result of equipment failure
  vi. Decommissioning and asset retirement liabilities
- Regulatory risk:
  i. unfavorable regulatory decisions
  ii. compliance with regulation and legislation
  iii. unforeseen changes to provincial or federal legislation affecting the company operations
- Other business risks:
  i. Forecasting operating and maintenance costs
  ii. Franchise loss
  iii. Weather
  iv. Market loss
  v. Fraud

487. In her evidence Ms. McShane stated that the presence of CIAC increases the effective debt ratio (or alternatively, decreases the effective equity ratio) and that CIAC represents a liability that is akin to debt, albeit interest-free.[342] Further, Ms.McShane stated that the lower the equity ratio, the higher the financial risk, and the higher the cost of equity for a given level of business risk.

488. The Utilities stated that the higher level of CIAC relative to total rate base, the higher is the operating leverage, or sensitivity of the earned return on rate base to unanticipated changes in revenues and/or costs. Ms. McShane provided an example in Table 2 of her evidence of the sensitivity of the ROE to an unanticipated change in O&M expense. Ms. McShane stated that the example showed that an unanticipated increase in O&M expense reduced the actual ROE below the allowed ROE by a wider margin for a utility with CIAC than it does for a utility with no CIAC and stated that greater CIAC introduces greater potential volatility in actual earnings.

489. Mr. Marcus submitted that in principle, the argument that CIAC creates operating leverage that results in increased operating risk and an increase in the cost of equity for shareholders has some theoretical validity since CIAC can create incremental operational risk. The Commission agrees with this observation, as further discussed below.

340 Exhibit 86.01, page 13, lines 364-366.
341 Exhibit 135.02, CCA-Utilities-31.
342 Exhibit 86.01, page 14, lines 381-383.

490. The Commission notes Ms. McShane's rebuttal evidence in which she acknowledges that the proposed management fee exceeds the likely deviation from the allowed return due to higher operating leverage, and includes compensation for other risks as well as the value of services provided.[343] Given the Commission's determination that there are no value added services provided by the Utilities with respect to the CIAC-funded assets, the Commission does not agree that the incremental level of business and financial risk associated with these assets, on its own, supports the management fee proposed by the Utilities.

### Management fee conclusions

491. The Commission determined above that the services related to CIAC-funded assets are not distinct from the utility services compensated for under the statutory scheme and that the incremental level of risk associated with these assets, on its own, does not support the management fee proposed by the Utilities. Consequently, the Commission does not accept the management fee proposal.

492. Additionally, the Commission considers that the concept of a management fee should be viewed in the context of the Alberta regulatory framework. For example, IPCAA noted the potential "double charging" for DFO customers that may occur if the TFOs are allowed to earn a management fee on assets paid for by a customer contribution. In this case, DFO customers would pay the management fee to the TFO (that the DFO would pass on to its customers), as well as the return to the DFO for the contribution made to the TFO, because the contribution would become part of the DFO's rate base.[344]

493. This is of particular concern in situations in the electric utility industry where the TFO and DFO are part of the same larger corporate entity. For ENMAX, EDTI and ATCO Electric TFOs, the corporate shareholder earns a rate of return on CIAC assets where the CIAC funding comes from the DFO affiliate, and the TFO affiliate would earn a management fee on those same assets. In her evidence, Ms. McShane expressed her view that corporate affiliations should not be a determinant of the appropriate compensation for CIAC and that compensation for CIAC should be provided to the regulated entity that constructs, owns, operates and manages the underlying assets and provides the related services.[345]

494. The Commission does not agree with the position advanced by Ms. McShane and the Utilities in this instance. The Commission considers that, for the corporate shareholder to receive a return on transmission assets funded by the DFO, because the contribution is added to the DFO's rate base, as well as a management fee provided to the TFO on those same transmission assets, would result in an unwarranted additional return to the corporate shareholder.

495. Nonetheless, even though the management fee proposed by the Utilities is not warranted, the Commission agrees with the Utilities that CIAC-funded assets contribute to business risk. In general, business risk would be expected to rise in proportion to assets. The Commission agrees with the Utilities that, without an increase in equity, CIAC-funded assets would cause an increase in financial risk and operating leverage risk.

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343 Exhibit 152.04, McShane rebuttal evidence on management fee, lines 378-385.
344 Exhibit 212.01, IPCAA argument, paragraph 29.
345 Exhibit 86.01, page 14, lines 381-383.

496. As outlined in Section 5 above, it has been the practice of the Commission and its predecessor to adjust for any differences in risk among the utilities by adjusting their individual equity ratios. The Commission has reaffirmed its adherence to this approach in this decision.

497. In this regard, the Commission notes that the equity ratios awarded in Decision 2009-216 were determined by examining the credit metrics for a sample of utilities with an A credit rating. The sample utilities used in Table 12 of Decision 2009-216 were exclusively Alberta utilities and therefore reflected the typical level of contributed assets of the Alberta utilities, as of 2009. These Alberta utilities were able to achieve A credit ratings at their observed credit metrics despite having a certain amount of CIAC-funded assets.

498. Furthermore, in the case of AltaGas, the EUB explicitly recognized in Decision 2004-052 that a high level of customer contributions increases business risk, when it set the equity ratio of AltaGas in the 2004 GCOC proceeding. In that decision, the EUB stated:

> The Board considers that AltaGas has greater business risk than the typical gas distribution company.
> AltaGas and ATCO Gas considered the business risks of AltaGas to be higher than the business risks of ATCO Gas, due to AltaGas' relatively small size, rural service area, geographically dispersed customers and high level of customer contributions.
> […]
> Considering all of the above, the Board concludes an appropriate common equity ratio for AltaGas is a continuation of its currently approved 41%.[346]

499. As the UCA pointed out in its argument, no utilities have been downgraded since the 2009 proceeding and, therefore, the Commission considers that the equity ratios awarded in Decision 2009-216 adequately reflected all of the Alberta utilities' business risks, including any risks associated with the CIAC-funded assets.

500. In this decision, the Commission continued the equity ratios awarded in 2009 for 2011 and 2012, with the exception of ATCO Electric TFO, AltaLink TFO, and ATCO Pipelines. Based on the data provided in Attachment A of Ms. McShane's evidence, CIAC as a percentage of gross rate base (inclusive of contributions) of the Alberta Utilities, in total, is expected to decrease from 17 per cent in 2009 to 15 per cent 2012.[347]

501. Specifically, the data provided in Attachment A of Ms. McShane's evidence shows that, while the level of CIAC for electricity and gas distributors is forecast to decrease from 21 per cent of gross rate base in 2009 to 18 per cent in 2012, the CIAC for TFOs is expected to increase from 9 per cent of gross rate base in 2009 to 12 per cent in 2012.[348] The Commission considers that addressing factors such as the maximum investment levels of the electricity and gas distributors will help to further reduce the amount of CIAC-funded assets in the future. In that regard, in Decision 2011-134, the Commission recently increased maximum investment levels substantially for ATCO Electric.[349]

502. With respect to the TFOs, the Commission considers that the approved Rider I will likely result in a reduction in the CIAC levels of the TFOs. Further, the Commission has initiated the

346 Decision 2004-052, page 53.
347 Exhibit 86.01, Kathleen McShane opinion, Attachment A, PDF page 214.
348 Ibid.
349 Decision 2011-134, Section 5.3.

Electric Transmission Contribution Policy proceeding[350] in which it will address aspects of the AESO's customer contribution policy. The outcome of this proceeding will likely affect the level of CIAC for the TFOs in Alberta.

503. In light of these factors, the Commission considers that the equity ratios awarded in this decision for 2011 and 2012 adequately reflect the Alberta utilities' business risks, including any risks associated with the CIAC-funded assets. On a go-forward basis, the Commission will consider any concerns related to the level of CIAC-funded assets on a utility-specific basis and, if necessary, adjust the equity thickness for the utilities.

## 7 Rider I matters

### 7.1 Background

504. Following concerns expressed by certain industrial customers with respect to the up-front payment of construction contributions for system access service (i.e. transmission) connections, the AESO proposed a new "Rider I" to finance these contributions. Rider I would allow customers to pay the construction contribution principal in equal monthly amounts, over a period of up to 20 years, plus a carrying cost (similar to an interest charge) on the unpaid contribution balance. Rider I would also allow for contributions that were previously paid for transmission facilities to be refunded and then re-paid through Rider I.[351] Rider I would only be available to fund contributions to transmission facility owners (TFOs).

505. The AESO first proposed Rider I in its 2010 GTA.[352] In that proceeding, the Commission determined that Rider I should be considered in conjunction with the management fee matter and stated in Decision 2010-606 that it "makes no findings in respect of the merits of Rider I at this time...Rider I will be considered in association with the management fee in the upcoming 2011 Generic Cost of Capital proceeding."[353]

506. The Utilities supported Rider I[354] because they are concerned about the increasing levels of customer contributions, including contributions to the TFOs by the distribution facility owners (DFOs).[355] Contributions by DFOs to transmission substation costs result in a transfer of rate base from a transmission utility to a distribution utility. High levels of contributed assets reduce the amount of a utility's rate base that can earn a return on capital for rate making purposes.

507. In addition to supporting Rider I, the Utilities proposed a management fee as compensation for managing the contributed assets.[356] This is discussed in detail in Section 6 above.

350 Proceeding ID No. 1162.
351 Exhibit 77.02, Appendix B – Previously-Filed Evidence on Amortized Construction Contribution Rider I, page 36 of 58, paragraph 191, PDF page 32.
352 Alberta Electric System Operator, 2010 ISO Tariff Application, Application No. 1605961, Proceeding ID No. 530.
353 Decision 2010-606, page 58, paragraph 302.
354 Exhibit 209.01, written argument of the utilities, page 67, paragraph 266.
355 Exhibit 86.01, opinion on management fee and Rider I, pages 6-7.
356 Exhibit 86.01, opinion on management fee and Rider I, pages 2-3.