EB-2024-0063

Ontario Energy Board

2024 Review of Cost Capital Parameters and Deemed Capital Structure

IGUA Compendium

Panel 2 - Concentric Energy Advisors

GOWLING WLG

5.2.3 Expected Market Returns and Estimating MRPs

The next CAPM input is the Market Risk Premium (MRP), which is measured by the expected long-term return on the equity market less the long-term government bond yield, which measures RF. Table 7 below provides useful guidance in determining a reasonable estimate for expected stock market returns, which in turn can be used to estimate MRPs, or to assess the reasonableness of MRP estimates. It is broken into two categories: (1) historical returns; and, (2) current (i.e., 2022-24) long-term market forecasts from 4 different sources. It is noteworthy that one of the sources of long-term forecasts (i.e., Horizon) provides summary statistics based on extensive surveys of finance professionals, and hence Table 7 provides a comprehensive view of the forecasts of the professional finance community. In particular, Horizon's report is based on the forecasts of 42 investment advisors, which includes prominent advisory firms (e.g., Aon, Mercer, and Willis Towers Watson), several large commercial and investment banks (e.g., Bank of New York Melon, Goldman Sachs Asset Management, J.P. Morgan Asset Management, Merrill, Morgan Stanley, UBS, etc.), and large asset managers (e.g., BlackRock, The Vanguard Group, etc.). As such, it provides a comprehensive representation of the views of finance professionals managing trillions of dollars of wealth.

Sikes (2022) (page 45) verifies the relevance of expected market returns by the financial community, noting "investors' expected market return should effectively set a ceiling on the ROE approved by regulators as utility stock is less risky than the overall stock market." The AUC for example, has also previously noted that such forecasts are informative and reaffirmed this position in the 2018 Alberta GCOC Decision, stating:

> Consistent with its determinations in previous GCOC decisions, the Commission continues to hold the view that return expectations of finance market professionals are germane to the determination of a fair ROE for regulated utilities.[34]

Hence, the AUC believes that such information is relevant, and I agree. In fact, I would argue that the beliefs of professionals who participate in the markets and influence market activity are far more relevant than market expectations determined using unrealistic growth assumptions, such as those I have seen provided by the utilities' experts in previous proceedings. In other words, market participant beliefs represent an important and practical

[34] Decision 22570-D01-2018, 2018 Generic Cost of Capital, page 97, para. 460.

"benchmark," against which any utility ROE estimate must be compared. Table 7 provides Canadian, U.S. and global historical evidence and forecasts; however, since I estimate the CAPM using the Canadian stock market, I focus my discussion on the Canadian evidence; although I would note that the expected U.S market return according to industry professionals of 6.84% is not that far off the Canadian average estimate of 6.1%, both of which are below my final estimate for expected market returns.

TABLE 7

HISTORICAL AND FORECAST EQUITY RETURNS

Source	**Horizon**	**Canada**	**U.S.**	**World / Developed Markets (excl. U.S.)**
HISTORICAL RETURNS				
1. Historical Data (Cleary Evidence, Table 6, Section 4.3.3)	Historical: 1938-2023	Real: 6.1% GA 7.3% AA		
2. Dimson, E., P. Marsh, and M. Staunton, "Long-Term Asset Returns," in *Financial Market History*, CFA Institute Research Foundation, December 2016.[35]	Historical: 1900-2015	Real: 5.6% GA 7.0% AA	Real: 6.4% GA 8.3% AA	Real (World Excl. U.S.): 4.3% GA 6.0% AA
3. "The Real Economy and Future Investment Returns," McKinsey & Company, January 17, 2017.[36]	Historical: 1915-2014		Real: 6.5%	
Average (Range)		**Real: 6.5%** (5.6%-7.3%)	**Real: 7.1%** (6.4%-8.3%)	**Real: 5.2%** (4.3%-6.0%)
FORECAST RETURNS				
4. . Institut québécois de planification financière (IQPF) and Financial Planning Standards Council (FPSC), "Project Assumption Guidelines," April 2024. Source: https://www.fpcanada.ca/docs/default-source/standards/2024-pag---english.pdf[37]	Long-term forecast	Nominal: 6.4%		Nominal: 6.5% (Foreign developed market equities)
5. Horizon Actuarial Services, LLC, "Survey of Capital Market Assumptions," 2023. Source: https://www.horizonactuarial.com/_files/ugd/f76a4b_1057ff4efa7244d6bb7b1a8fb88	Intermed. (<10 years) Long-term		U.S. Large Cap (Nominal) 6.90% (4.8-10.2%) 7.37%	Non-US Dev. Mkts. 7.49% (4.7-10.3%) 7.78%

[35] Appended to this evidence as Attachment AW.
[36] Appended to this evidence as Attachment AX.
[37] Appended to this evidence as Attachment AY.

236e6.pdf[38]	(10-years or more)		(5.6-10.2%)	(6.1-9.8%)
6. Franklin and Templeton Investments, "Capital Market Expectations 2024 and Beyond," December 2023.[39] Source: https://pages.to.franklintempleton.com/rs/848-IAP-939/images/Outlook%202024%20Event_ian.pdf?version=0	10-year forecast	Nominal: 7.2%	Nominal: 7.4%	Nominal: EAFE Equities: 8.6%
7. "Capital Market Assumptions" BlackRock, May, 2024.[40] https://www.blackrock.com/institutions/en-us/insights/charts/capital-market-assumptions	10-year forecast 20-year forecast	Large Cap - Nominal: 4.01% 5.19%	Large Cap – Nominal: 5.42% 6.53%	World excl. Can (in CAD): Nominal: 5.29% 6.39%
Average (Range)		**Nominal: 6.1%**[41] (4.0%-7.2)	**Nominal: 6.84%** (5.4%-7.4%)	**Nominal: 7.14%** (5.3%-8.6%)

The first three sources in Table 7 provide historical long-term real returns for Canadian, U.S. and global stocks over three extremely long time periods (i.e., 86 years, 116 years and 100 years). The Canadian evidence suggests average real returns of 6.5%, with a range of estimates of 5.6% to 7.3%. Combining these figures with 2% expected inflation would suggest expected nominal returns of 8.5%, ranging from 7.6% to 9.3%, based solely on historical results.

The next four sources represent 2023-24 estimated long-term market returns from a number of important and reputable sources with various mandates (i.e., the Financial Planning Standards Council; consulting firms, investment and commercial banks, and other investment management firms). All of these estimates are provided in nominal terms. The Canadian market nominal estimates range from 4.0% to 7.2%, and average **6.1%.** Deducting the 2% expected inflation, this translates to an average *real* return of 4.1%. In other words, most market professionals are of the belief that Canadian stocks are unlikely to earn their historic long-term *real* rates of return in the 5.6-7.3% range over the next 10-20 years.

[38] Appended to this evidence as Attachment AZ.
[39] Appended to this evidence as Attachment BA.
[40] Appended to this evidence as Attachment BB.
[41] This average is determined by taking the average of BlackRock's two forecasts and using it as one of three estimates (i.e., three different sources).

While I do not focus on the U.S. evidence, it is noteworthy that the average expected market return for U.S. stocks is 6.84% - well below its average of the last few decades. This is important to recognize, as it indicates that expected market return (and related MRP) forecasts that rely heavily on recent U.S. stock returns (such as that done by LEI which uses historical averages from five recent U.S. time periods in estimating potential MRPs), will be overly optimistic. In fact, it is well-known that the U.S. stock market has experienced exceptional returns over the last few decades, producing abnormally high real returns relative to its longer term history, and relative to global equity returns in other markets. I have attached an article as Attachment AD, which expands on this matter. The authors note that: "The real return on U.S. stocks from 1950 through 2023 was 7.63 per cent, and 7.16 per cent for the 20 years ending December 31, 2023. A real return above 7 per cent is exceptional even for the U.S. market. From 1900 through 1950, U.S. stock returned a real annualized 5.57 per cent." They further note that "Global real stock returns from 1900 through 2023 were 5.16 per cent annualized" (based on analysis of 38 developed markets). Putting this in perspective, they note that: "The often cited 10-per-cent return for stocks based on the post-1950 period is roughly equivalent to a 7-per-cent real return in the historical data. That is about 2 per cent higher than unbiased estimates of U.S. expected returns, U.S. equity returns before 1950 and global stock returns spanning 1890 through 2023." Similar to the U.S. stock returns forecast by investment professionals reported in Table 8, the authors expect future real returns for U.S. stocks in the 4.25% range, and combine this with 2.5% expected inflation to arrive at an expected U.S. stock market return of 7.24%, much more in line with the nominal forecasts provided in Table 8.

I believe that both historical returns and current expectations of market professionals represent the <u>best</u> sources of information regarding future long-term market returns. Combining the historical results and market forecasts for Canada that are presented in Table 7 and discussed above suggests a range of estimates in the 4.0% to 9.3% range, and the mid-point between historical averages (when adjusted to nominal terms) of 8.5% and the forecast average of investment professionals which is 6.1%, of 7.3%. This is consistent with my usual recent assumptions that an appropriate range for expected long-term Canadian stock market returns is 6-9%, and that the mid-point of **7.5% represents an appropriate point estimate**.[42] This is

[42] This estimate of 7.5% for future expected Canadian market returns is reflective of my analysis of historical market returns and forecasts for future returns from investment professionals discussed above. Attachment BC

well above the consensus view of financial professionals of 6.1% that is estimated in the bottom portion of Table 7, but below historical averages, so it seems reasonable. It is important to recognize that this expected market return of **7.5%** represents an **upper bound** for the cost of equity to regulated utilities (before adding 0.50% for flotation costs), since they are less risky than the average company in the market. This aligns well with my DCF estimate for the market of 7.40% (in Section 5.2.2), but is below my implied CAPM estimate for the market of 8.3% (discussed later in this section).

Figure 11 shows that the world market MRP, as measured by the return on the market less the long-term government bond yield over the 1900-to-2015 period, provided an arithmetic average of 4.1% (geometric mean of 3.2%). These means are lower than the corresponding U.S. figures (5.8% and 4.4%) and slightly below the Canadian figures (4.2% and 3.3%) over that period. The figures for Canada are in line with the differences between the average (and geometric mean) returns for Canadian stock and bond returns over the 1938 to 2023 period, which were 4.97% (4.16%) as previously reported in Table 6. These numbers are also consistent with expected MRPs according to a recent survey of analysts, companies, and finance professors, which were in the 5 to 6% range for most regions. The results for Canada and the U.S. are reported in Figure 12, with 2024 figures of **5.2%** and 5.5% respectively.

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provides a July 3, 2024 article (published after I had made this estimate) discussing the iShare S&P/TSX 60 Index ETF (XIU). The article confirms the reasonableness of my estimate, suggesting that: “The average annual total return since inception for XIU is 7.6 per cent. If you invest in big Canadian companies, that’s your benchmark for measuring returns over periods of 10 years and longer.”

as previously discussed, and, therefore, best represent Ontario's utilities from an investment perspective.

F. Capital Asset Pricing Model ("CAPM")

The CAPM is based on the relationship between the required return of a security and the systematic risk of that security. As shown in Equation [4], the CAPM is defined by four components, each of which should represent investors' forward-looking view:

[4] $$Ke = rf + \beta(rm - rf)$$

where:

Ke = the required ROE for a given security;

β = Beta of an individual security;

rf = the risk-free rate of return; and

rm = the required return for the market as a whole.

The term (rm – rf) represents the Market Risk Premium ("MRP"). According to the theory underlying the CAPM, since unsystematic risk can be diversified away, investors should be concerned only with systematic or non-diversifiable risk. Non-diversifiable risk is measured by beta, which is defined as:

[5] $$\beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)}$$

where:

re = the rate of return for the individual security or portfolio.

The variance of the market return, noted in Equation [5], is a measure of the variability in the general market, and the covariance between the return on a specific security and the market reflects the extent to which the return on that security will respond to a given change in the market return. Thus, beta represents the risk of the security relative to the market.

Each of the variables used in the CAPM are discussed in the subsection below.

1. Risk Free Rate

Bond yields increased sharply in 2022 and 2023 and are generally not expected to return to the very low interest rate environment that prevailed in the decade following the financial crisis of 2007-2009. In general, forecast bond yields, as opposed to the current risk-free rate, best reflect investor expectations and are therefore appropriate for modeling the cost of capital.

The 30-year bond yield is appropriate to estimate the expected equity return for Ontario's utilities as it best matches the risk-free instrument with the lives of utility assets on which the return depends. A 30-year government bond yield forecast is not available from Consensus Economics; therefore, our CAPM analysis relies on the 2025 through 2027 average Consensus Economics forecast of the Canadian 10-year government bond as shown in Figure 14 below and adds the historical spread between 10- and 30-year government debt. This period was chosen to be forward looking, as required for an equity return. We selected a three-year forecast of the Canadian bond yield because it reflects the medium-term outlook for government bond yields as central banks continue to focus on bringing inflation down to target levels. Even with an annual adjustment formula, a forward-looking bond yield is appropriate, as the cost of capital is a forward-looking estimate.

Figure 14: Forecast for 10-Year Government Bond Yields[73]

	2025	2026	2027	Average
Canada	3.10%	3.10%	3.20%	**3.13%**
U.S.	3.80%	3.60%	3.60%	**3.67**%

Although the current spread between 10- and 30-year government bond yields in Canada is negative, the average spread between 10- and 30-year government bond yields over the past 10 years has been approximately 33 basis points in Canada and 47 basis points in the U.S.[74] As illustrated in Figure 15 the projected yields on 30-year government bonds over the period 2025-2027 are 3.46 percent in Canada and 4.14 percent in the U.S. By comparison, the 30-day average of the 30-year bond yields in Canada and the U.S. stood at 3.37 percent and 4.50 percent, respectively, as of June 30, 2024. The

73 Consensus Forecasts by Consensus Economics Inc., Survey Date April 8, 2024, p. 3 and 29.

74 Historical spreads were calculated using daily bond yields published on Bloomberg from June 2015 through May 2024.

Concentric views these developments as consistent with the long-term trend of Canadian and U.S. interest rates, and central bank policies, converging.

2. Beta

We have sourced betas for the Canadian and U.S. proxy group companies from both Value Line and Bloomberg. Value Line publishes the historical beta for each company based on five years of weekly stock returns and uses the New York Stock Exchange as the market index. Bloomberg produces beta estimates based on parameters entered by the user. We have computed Bloomberg betas based on five years of weekly stock returns and using the S&P 500 or the S&P/TSX Composite as the market indexes. Both Value Line and Bloomberg compute adjusted betas to compensate for the tendency of beta to revert toward the market mean of 1.0 over time. The betas used in our CAPM analyses are shown in Figure 16.

Figure 16: Value Line and Bloomberg Betas

Proxy Group	Value Line	Bloomberg
Canadian	0.77	0.85
U.S. Electric	0.95	0.91
U.S. Gas	0.85	0.82
North American Electric	0.92	0.88
North American Gas	0.83	0.87
North American Combined	0.90	0.88

LEI's CAPM analysis relies on raw, unadjusted betas calculated using daily return data for the past five years. LEI then adjusts these betas for differences in financial leverage between Ontario's utilities and the companies in LEI's various proxy groups. We do not agree with LEI's approach to beta, and in particular the use of raw betas, as discussed below in our response to LEI.

There are two primary reasons to adjust raw betas. First, empirical studies have provided evidence that an individual company beta is more likely than not to move toward the market mean of 1.0 over time.[77] Second, adjusting beta serves a statistical purpose. Because betas are statistically estimated and have associated error terms, betas greater than 1.0 tend to have positive estimated errors and thus tend to overestimate future returns. Betas below the market average of 1.0 tend to have

[77] Marshall E. Blume, The Journal of Finance, "On the Assessment of Risk," March 1971, Volume 26, No. 1, p. 1-10, and Marshall E. Blume, The Journal of Finance, "Betas and Their Regression Tendencies," June 1975, Volume 30, No. 3, p. 785-795.

negative error terms and underestimate future returns. Consequently, it is necessary to adjust forecasted betas toward 1.0 to improve forecasts.[78] As current stock prices reflect expected risk, one must use an expected beta to appropriately reflect investors' expectations. A raw beta reflects only where the stock price has been relative to the market historically and is an inferior proxy for the expected returns when compared to the adjusted beta. Of note, utility betas have increased since February 2020. This has caused a decrease in the effect of the standard Blume adjustment.

Dr. Blume specifically studied four groups of betas, ranging from a very low beta group (averaging 0.50, and similar to the utility industry) to a very high beta group. Dr. Blume found that his adjustment best predicted future betas for each of the four risk groups over the next seven years. Dr. Blume found that a low beta portfolio that averaged 0.50 migrated towards the grand mean of all betas of 1.0 approximately in accordance with the Blume formula. This study provides empirical evidence that betas migrate towards 1.0 and do indeed exceed their long-term unadjusted averages. Given that the CAPM is intended to estimate the forward-looking cost of capital, it is important to reflect a forward view of beta and its tendency to migrate towards the market mean over time, which is not limited to the long-term historical average of the industry beta.

Dr. Jonathan Lesser was retained by the BCUC to review the methodologies used to estimate the cost of capital as part of the 2021-2022 generic cost of capital proceeding in British Columbia. Dr. Lesser also recognized the merits of using Blume adjusted betas in the CAPM analysis.

> *Because regulators establishing the allowed ROE for a regulated utility are basing that allowed ROE on expected market conditions over an indefinite future, adjusted beta values are typically considered to be more appropriate when applying the CAPM.*[79]

In a follow-up interrogatory on this issue, Dr. Lesser further clarified his position:

> Does Dr. Lesser see merit in adjusting utility betas to anything other than the market value of one? If so, please explain.
>
> Response:

[78] Roger A. Morin, *New Regulatory Finance*, p. 74.
[79] Regulated Utility Cost of Capital: Theory and Canadian Practice, Jonathan A. Lesser, Continental Economics, Inc., August 4, 2021, p. 42.

> *Dr. Lesser assumes the question is asking about methodologies that adjust raw beta values towards their theoretical long-term values. Dr. Lesser is not aware of beta adjustment methodologies that adjust raw beta values towards a value other than one.*[80]

Dr. Lesser further expanded this position in his response to a clarifying question by the Commission:

> Please confirm, or explain otherwise, if Dr. Lesser endorses the use of the Blume-adjusted Beta for utilities' ROE determination.
>
> Response:
> *I recommend the use of Blume-adjusted beta values. Furthermore, I recommend the use of the beta values reported by Value Line to ensure there is consistency amongst all CAPM estimates.*[81]

We agree with Dr. Lesser, and in Concentric's experience, Value Line and Bloomberg are the most commonly employed sources of beta for cost of capital analysis.

The BCUC noted in its September 2023 Decision and Order that it had not previously accepted the use of Blume adjusted betas. However, the BCUC reversed its previous decisions on this issue, stating:

> *However, the Panel notes Mr. Coyne's explanation that Dr. Blume found that his adjustment was applicable to all betas, ranging from a low of 0.50 to a high of 1.53, and in Mr. Coyne's view, there is no reason to expect that regulated utilities would be an exception to this rule. Given the views of the two experts in this proceeding and since none of the parties object to Mr. Coyne's use of Blume-adjusted data, the Panel accepts the experts' recommendation to use the Blume-adjusted beta estimates for the proxy groups.*[82]

Concentric submitted a full cost of capital analysis in the consultation on Cost of Capital conducted by the OEB in 2009. Concentric's CAPM analysis included the standard Blume adjusted betas from Bloomberg and Value Line, just as we have utilized them in this proceeding. In its decision, the OEB took no issue with Concentric's use of betas with the standard adjustment toward the market mean of 1.0.

80 British Columbia Utilities Commission – Generic Cost of Capital – Project No. 1599176 – BCUC Staff Consultant Response, Dr. Lesser Responses to FortisBC Set 1, November 30, 2021, 10.1.

81 Responses to British Columbia Utilities Commission Information Request No. 2 Generic Cost of Capital Prepared by Jonathan Lesser, Ph.D., June 10, 2022, 7.1.

82 British Columbia Utilities Commission, Decision and Order G-236-23, September 5, 2023, p. 75.

3. Market Risk Premium ("MRP")

Estimates of the MRP generally fall into two categories, *ex-post* (historical arithmetic average) and *ex-ante* (forward looking). The historical MRP is based on the arithmetic mean of the equity market returns for large company stocks over the income only return on long-term government bonds, based on data from Kroll (formerly Duff & Phelps). In Canada, the historical MRP is based on return data from 1919-2023, while in the U.S., the historical MRP is calculated using return data from 1926-2023. The forward-looking MRP is calculated by subtracting the risk-free rate for each country from the estimated total return for the overall market, as calculated using the DCF methodology for the S&P/TSX Composite Index in Canada and the S&P 500 Index in the U.S. Exhibits CEA-6.1 and CEA-6.2 show the derivation of the forward-looking MRP for Canada and the U.S.

Because, as noted, the U.S. and Canadian economies are highly integrated and capital flows freely across the border, the risk premiums for each country are highly correlated. Accordingly, it is reasonable to derive a single estimate of the MRP for Canada and the U.S., as provided in Figure 17.

Figure 17: Market Risk Premia – Canada and U.S.

	Canadian	**U.S.**
Actual Historical	5.68%	7.17%
Forward-Looking	12.09%	11.30%
Average	9.06%	

Forward-looking MRPs currently are higher than historical MRPs, reflecting the fact that the historical MRP is based on higher average government bond yields than are available in the current interest rate environment. Noting the substantial difference between the historical and forward market risk premiums, Concentric has relied on the average actual historical MRP for Canada and the U.S. of 6.39 percent in our CAPM analysis. The actual historical MRP may be understated, however, because there is an inverse relationship between interest rates and the MRP, meaning that as interest rates increase (decrease), the MRP decreases (increases). The average 30-year bond yield over the course of the historical periods over which these MRPs were calculated by Kroll was approximately 5.6 percent in Canada and 4.9 percent in the U.S., in contrast to the currently projected 3.5 – 4.1 percent bond yields today. Our use of the actual historical MRP is a conservative (lower) estimate of the market risk premium when interest rates remain below the long-term historical average levels in both Canada and the U.S.

4. CAPM Results

The results of the CAPM analysis, including an adjustment for flotation costs and financial flexibility, are provided in Figure 18 and in Exhibit CEA-7.1, CEA-7.2 and CEA-7.3. Although we have presented our CAPM results using three different MRPs (i.e., an average of the forward-looking and historical MRP, a forward-looking MRP, and an actual historical MRP), as discussed above, our recommended ROE for Ontario's utilities uses the CAPM results with the actual historical MRP.

Figure 18: CAPM ROE Results[83]

Proxy Group	Average MRP	Forward-looking MRP	Historical MRP
Canadian	11.58%	13.80%	9.36%
U.S. Electric	13.07%	15.52%	10.62%
U.S. Gas	12.20%	14.39%	10.00%
North American Electric	12.58%	14.93%	10.23%
North American Gas	12.18%	14.47%	9.89%
North American Combined	12.57%	14.93%	10.22%

In addition, Concentric used the Hamada equation to adjust for differences in financial leverage between the North American proxy group companies (based on their actual capital structure at the operating company level) and the Ontario utilities (based on the current deemed capital structures for each sector). Figure 19 below shows the adjustment to the CAPM results that would be required based on this analysis.

83 Results include an adjustment of 50 basis points for flotation costs and financial flexibility.

Figure 19: Hamada Equation – Adjustment to CAPM Results in Basis Points

Proxy Group	Average MRP	Forward-looking MRP	Historical MRP
Electric T&D (40%)	+194	+251	+138
Electric Generation (45%)	+91	+117	+64
Gas Distribution (38%)	+231	+298	+163

Concentric performed these calculations using the Hamada equation to analyze the effect of financial leverage on returns, but our ROE recommendation is based in part on CAPM results that are not adjusted for such differences in leverage.

G. Flotation Costs and Financing Flexibility

It is common practice for Canadian regulators to approve an adjustment for flotation costs and financing flexibility, with 50 basis points being the norm (as discussed below). The OEB included this adjustment in the 2009 Report; however, LEI is recommending that the authorized ROE for Ontario's utilities should not be adjusted for flotation costs and financial flexibility.

The adjustment for flotation costs compensates the equity holder for the costs associated with the sale of new issues of common equity. These costs include out-of-pocket expenditures for the preparation, filing, underwriting and other costs of issuance of common equity including the costs of financial flexibility such that there is adequate cushion to raise equity in challenging capital market conditions. As the purpose of the allowed rate of return in a regulatory proceeding is to estimate the cost of capital the regulated company would incur to raise money in the "primary" markets, an estimate of the returns required by investors in the "secondary" markets must be adjusted for flotation costs in order to provide an estimate of the cost of capital that the regulated company requires. The adjustment also takes into account the need for financial flexibility, meaning that utilities are capital intensive businesses and must be able to access capital markets at all necessary times regardless of conditions in capital markets or the economy. The adjustment is particularly necessary because authorized ROEs in Canada tend to be lower and Canadian utilities are more thinly capitalized than US utilities, as discussed in Section VII of our report.

The practice of allowing a 50 basis point adjustment for flotation costs and financing flexibility is widespread across Canada. As shown in Figure 20, of the ten jurisdictions examined, seven have change to the OEB's current practice is warranted or necessary. While the deemed debt rate can inform the OEB's assessment of utility-specific debt rates, the rote application of a cap could result in utilities not being provided the opportunity to recover prudently-incurred costs. Concentric specifically disagrees with the extension of the cap to Enbridge Gas and OPG under LEI's proposal. The continued use of the forecasted rates by the utilities will allow the utilities, in circumstances where their cost of debt is expected to exceed the cap, for reasons of risk differentials (e.g., due to timing differences or if a utility faces risk differentials to a R-1 rating) to demonstrate why their utility-specific debt cost is reasonable.

F. Long-Term Debt Rate

The OEB has asked parties in **Issue #6** to comment on whether the Board should continue to follow the same process for determining the cost of long-term debt as discussed in the 2009 Report. If the answer to Issue #6 is no, the Board has asked in **Issue #7** how the long-term debt rate should be set.

In general, the long-term cost of debt for ratemaking purposes is based on embedded costs, subject to the use of a deemed long-term cost of debt in certain circumstances for electricity distributors. The Board noted in its 2009 Report that the deemed long-term debt rate "will act as a proxy or ceiling for what would be considered to be a market-based rate by the Board in certain circumstances."[42] For example, for affiliate debt with a fixed rate, the deemed long-term debt at the time of issuance will be used. For affiliate and third-party variable-rate debt, as well as debt callable on demand within the test year period, the long-term debt rate will be a ceiling on that debt's rate. For debt callable on demand outside the test year period, it will be treated as if it is not callable. The Board also noted that "the long-term debt guidelines relating to electricity distribution utilities are expected to evolve over time and are expected to converge with the process used by the Board to determine the amount and cost of long-term debt for natural gas distributors."[43]

The Board determines the deemed long-term debt rate formulaically based on the 30-year Government of Canada ("GOC") bond yield forecast, plus the average historical spread between A-rated Canadian utility bond yields and 30-year Government of Canada bond yields. The 30-year GOC

42 EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (OEB Report), December 11, 2009, p. 53-54.

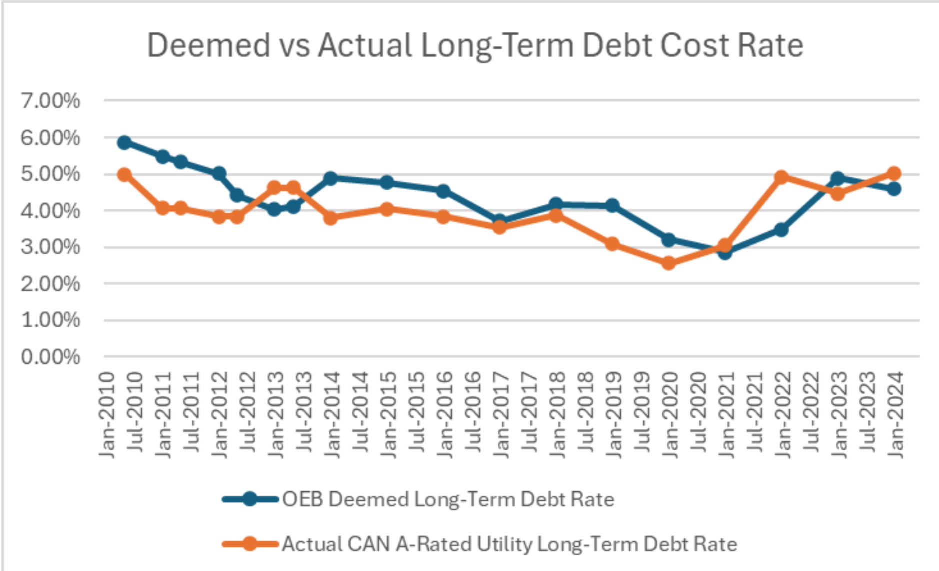
43 Ibid, p. 52.

bond yield forecast is determined using a forecast of the 10-year GOC bond yield sourced by Consensus Forecasts and adding the historical spread between 10- and 30-yr GOC bond yields. The 30-year GOC bond yield forecast and both spreads (the 10-year to 30-year spread, as well as the A-rated utility to 30-year spread) are determined by averaging the business days of the month three months in advance of the new rates' effective date. For example, for rates effective January 1, 2024, the deemed long-term debt cost rate was calculated as 4.58% and was determined as follows:

10-Year GOC Bond Yield Forecast, sourced by Consensus Forecasts, as of Sept. 2023 = 3.250%	+	Historical 30-year GOC to 10-Year GOC Spread for the month of Sept. 2023 = -19.6 bps	+	Historical Canadian A-Rated Utility Bond Yield to 30-Year Bond Yield Spread for the month of Sept. 2023 = +152.5 bps	=	Deemed Long-Term Debt Rate for rates effective Jan. 1, 2024 = 4.58%

Concentric compared the OEB's deemed long-term debt rates published since 2010 with actual Canadian utility long-term debt rates tracked by a Bloomberg index of 30-year Canadian A-rated utility bonds. The actual long-term debt rates were averaged annually to compare to the calendar rate years in which the deemed long-term debt rates were effective. Since 2010, the OEB's deemed long-term debt cost rate has had periods of being above and below the Bloomberg index, and averaged 40 bps higher than the index. Both measures may understate actual debt costs if issuance costs are not included.

Figure 2: Deemed vs Actual Long-Term Debt Cost Rate



Concentric also looked to other Canadian jurisdictions to determine if other approaches may be helpful in evaluating Ontario's deemed long-term debt rate formula. In Alberta, the Alberta Utilities Commission ("AUC") states that "the cost of debt (or the interest rate a utility pays on debt) is not typically set by the AUC, but is determined in the market, based on who is willing to lend the utility money." [44] In the 2024-2028 Performance-Based Regulation Plan for Alberta Electric and Gas Distribution Utilities, the AUC uses the actual embedded debt cost to determine reasonable long-term debt rates.[45] The AUC's Determination of the Cost-of-Capital Parameters in 2024 and Beyond includes a comparative analysis of the embedded average debt rate among distribution and transmission utilities in Alberta, in which the AUC determined an embedded average debt rate of 4.20 percent is reasonable. This figure was higher than the overall simple average debt rate for the utilities analyzed, which was 4.09 percent based on 2023 data; however, the AUC errs on the conservative side due to the resulting lower EBIT coverage and funds from operations coverage ratios.[46]

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44 Alberta Utilities Commission website, "Rate of Return", accessed May 30, 2024. https://www.auc.ab.ca/rate-of-return/

45 Alberta Utilities Commission, 2024-2028 Performance-Based Regulation Plan for Alberta Electric and Gas Distribution Utilities, October 4, 2023.

46 Alberta Utilities Commission, Determination of the Cost-of-Capital Parameters in 2024 and Beyond, October 9, 2023.

In British Columbia, in its May 2013 Generic Cost of Capital Decision, the British Columbia Utilities Commission ("BCUC") found that "the cost of deemed long-term debt (rate and term) for each utility should be addressed separately on a case-by-case basis."[47] In addition, the BCUC found that the following methodology should be used as a "guideline" going forward for setting the deemed long-term debt rate applicable to a small utility without third-party debt:

1. *Assign a credit rating on a stand-alone basis, and then obtain indicative quotes from investment dealers or banks based on the credit rating of a comparable proxy issuer. Using proxy companies that are engaged in the power sector or energy infrastructure can help to minimize subjectivity. A reasonable deemed stand-alone rating for a small regulated utility appears to be in the range of BBB to BBB (low), with the deemed debt cost set on this basis.;*

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

3. *Determine the credit spread of a comparable corporate proxy issuer in similar industries or lines of business (e.g., regulated utility, power generation, energy infrastructure) at the same term to maturity as that selected as the benchmark GoC bond.*[48]

The OEB's approach to the deemed long-term debt cost rate is similar to and a specific form of the BCUC approach outlined above (i.e., the Board's deemed long-term debt rate methodology specifies a deemed credit rating of "A" in Step 1, determines the 30-year Long Canada Bond Forecast ("LCBF") as the reasonable benchmark in Step 2, and applies the appropriate historical spread, as in Step 3).

Concentric finds that the general use of embedded debt costs of each individual utility company is reasonable and appropriate for previously-incurred debt, and further that utilities should be allowed to forecast debt rates for debt that will be incurred during the rate plan, subject to review and approval by the OEB.

47 British Columbia Utilities Commission, Generic Cost of Capital Proceeding (Stage 1), Decision May 10, 2013, p. 110.

48 British Columbia Utilities Commission, Generic Cost of Capital Proceeding (Stage 1), Decision May 10, 2013, p. 107-108.

If the Board were to modify its approach to the deemed long-term debt cost rate, Concentric suggests considering a long-term debt rate benchmarking intended to confirm that the Board's deemed long-term debt cost rate is within reasonable error-bounds of actual utility debt costs. We further recommend adopting the same approach we recommend to the ROE formula (discussed in Section VI with reliance on bank forecasts for the 30-year bond yield versus the current approach that relies on the Consensus 10-year forecast plus a 10-30 spread. In either case, we recommend using 90-day averages for spreads versus the current month of September only.

LEI's Recommendation and Concentric's Response

LEI recommends considering publicly available reputable sources for 30-year bond yield forecasts for the Long Canada Bond Forecast, and further using Bloomberg's BVCAUA30 BVLI Index (12-month trailing average) for the A-rated utility spread over the Long Canada Bond Forecast. Lastly, LEI recommends using the deemed long-term debt rate as a cap for debt costs for all jurisdictional utilities, not just electricity distributors and transmitters.

Subject to our other recommendations above, we agree with LEI regarding the use of 30-year forecasts versus the current approach that relies on the Consensus 10-year forecast plus a 10-30 spread.

Concentric does not agree, however, about the automatic application of a cap on debt costs. The rejection of a uniform application of the cap would be consistent with the OEB's findings in EB-2010-0008, where the OEB found that OPG's actual cost of debt was more appropriate for rate setting purposes than a deemed cost of debt, and that the "deemed long-term debt rate is only intended to apply where a utility has no actual long term debt (or where the debt is held by an affiliate)."[49] Further, capping all utilities at the deemed debt cost would not be reflective of the spectrum of credit ratings assigned to regulated utilities. With the index constituent bonds comprising issuances rated A+, A, and A-, entities like OPG that are rated on the lower end of this spectrum would not be appropriately compensated for their cost of debt, given that each notch lower on the credit rating scale entails a higher cost of funding. As with our findings regarding the deemed short-term debt rate, Concentric does not believe a change to the OEB's current practice in this regard is warranted or necessary, and utilities should continue to be provided with the opportunity to forecast debt rates for debt that will be incurred during a rate plan. While the

[49] Decision with Reasons (EB-2010-0008), March 10, 2011, p. 125.

deemed debt rate can inform the OEB's assessment of utility-specific debt rates, the rote application of a cap could result in utilities not being provided the opportunity to recover prudently-incurred costs.

The OEB has also asked parties in **Issue #8** to comment on whether the Board should allow Ontario's utilities to recover transaction costs associated with the issuance of long-term debt, consistent with the current approach that was adopted in the 2009 Report. In Concentric's view, debt issuance costs are a legitimate cost of funding the operations of the utilities and should be recovered in rates through the embedded cost of long-term debt, as is the OEB's current practice. Debt issuance costs include fees and expenses for underwriting the debt security, legal services, security exchange registration, and fees paid to credit rating agencies.

Transaction costs are unavoidable expenses that arise during regular business operations, thereby raising the overall costs of operations and capital expenditures for utilities. Total underwriting costs can vary across debt instruments and their tenures, with longer tenured debt resulting in higher fees for the utility, reaching upwards of 100 bps of the total debt instrument amount. For example, Hydro One's January 2023 sustainable bond issuance of $1.05 billion cost the utility $4.3 million, or approximately 41 basis points of debt raised[50].

Other jurisdictions have adopted the allowance for debt transaction cost recovery. In the U.S., for example, FERC allows utilities to recover debt issuance costs through the deferred debits account, which amortizes the debt issuance costs over the life of the security using the bonds outstanding method (i.e., which approximates the effective interest method). In Concentric's experience, a similar approach is commonly used in many U.S. state jurisdictions.

50 For example, Hydro One's financing cost of 41 basis points, or approximately $4.3 million, is a one-time fee that is amortized over the life of the debt instrument, adding a small incremental expense to the borrower's total debt expense.

Ontario Energy Association (OEA)

Answer to Interrogatory from
Association of Major Power Consumers in Ontario (AMPCO) / Industrial Gas Users Association (IGUA)

INTERROGATORY

Reference:

On pages 69-70, Concentric discusses its market risk premium (MRP) estimates it uses in its CAPM Ke calculations, and its final CAPM Ke estimates.

On page 70, Concentric states:

> *Although we have presented our CAPM results using three different MRPs (i.e., an average of the forward-looking and historical MRP, a forward-looking MRP, and an actual historical MRP), as discussed above, our recommended ROE for Ontario's utilities uses the CAPM results with the actual historical MRP.*

Question(s):

a) Please provide the source documents, as well as workpapers including all data and calculations used to estimate the historical MRP estimates for Canada and the U.S.

b) Please confirm that the historical MRP estimate for Canada of 5.68% is 35% higher than the arithmetic average estimate of 4.2% provided in the Dimson et al. (2016) study[41] (which examines MRPs over the 1900-2015 period), and is 72% above the geometric average of 3.3% determined in the same study. If not confirmed please provide the actual percentage differences.

c) Please confirm that the historical MRP estimate for the U.S. of 7.17% is 24% higher than the arithmetic average estimate of 5.8% provided in the Dimson et al. (2016) study (which examines MRPs over the 1900-2015 period), and is 63% above the geometric average of 4.4% determined in the same study. If not confirmed please provide the actual percentage differences.

[4] This study is included as Exhibit AY of Exhibit M4 (Dr. Cleary's evidence), and is summarized in Figure 12 on page 40 of that evidence.

d) Please explain why Concentric's historical MRP estimates are so much higher than those included in the Dimson et al. (2016) study, given the significant overlap of a large number of annual observations included in both estimates.

e) Please confirm that Concentric estimates its forward-looking Canadian MRP of 12.09% using the Constant Growth DCF Model, with calculations provided in Exhibit CEA-6.1 of the Appendix that uses an expected dividend yield of 3.60% and an expected growth rate of 11.95%, which translates into an expected market return of 15.56%. Concentric then subtracts its RF estimate of 3.46% to arrive at a Canadian forward-looking MRP of 12.09%. If not confirmed, please explain.

f) Please confirm that the company growth estimates used to calculate the average market growth expectations for the Canadian market are based on only 60 (of 230) company growth estimates, with 170 company growth estimates not being available. If not confirmed, please explain.

g) Please confirm that the company growth estimates used to calculate the average market growth expectations for the Canadian market range from +194.72% to -29.16%. If not confirmed, please provide the range in growth estimates for the companies used to estimate the market growth estimate.

h) Given the lack of growth data for 170 (74%) of the 230 companies included in the S&P/TSX Index, as well as the wide variability in such growth estimates that are available, please explain why Concentric did not follow common finance practice and simply use its estimate of long-term nominal GDP growth of 3.84% for Canada as its growth estimate and combine it with the average expected S&P/TSX dividend yield of 3.60% to estimate the expected return on the market (which would equal 7.44%), and hence the MRP.

i) Please confirm that Concentric estimates its forward-looking U.S. MRP of 11.30% using the Constant Growth Model, with calculations provided in Exhibit CEA-6.1 of the Appendix that uses an expected dividend yield of 1.73% and an expected growth rate of 13.71%, which translates into an expected market return of 15.45%. Concentric then subtracts its U.S. RF estimate of 4.14% to arrive at a U.S. forward-looking MRP of 11.30%. If not confirmed, please explain.

j) Please confirm that the company growth estimates used to calculate the average market growth expectations for the U.S. market range from +189.05% to -24.00. If not confirmed, please provide the range in growth estimates for the companies used to estimate the market growth estimate.

k) Can Concentric please reconcile such high predicted growth rates in earnings (and dividends) for Canadian (11.95%) and U.S. (13.71%) companies with Concentrics' own forecast of expected nominal GDP growth rate for the Canadian and U.S. economies of 3.84% and 4.04% respectively? Please explain why we can expect corporate profits to grow at 12-14%, despite the respective economies only growing at an annual rates that are less than one-third of these growth figures at around 4%.

l) Can Concentric please reconcile such high predicted expected market returns for Canadian (**15.56%**) and U.S. (**15.45%**) companies with the long-term average expectations of market professionals for expected market returns of **6.1%** for Canada and 6.8% for the U.S., as provided in Table 7 of Exhibit M4 (Dr. Cleary's evidence)?

m) Please explain why Concentric disregards the forward-looking and average MRP CAPM Ke estimates.

Response:

a) Please see AMPCO/IGUA-10(a), Attachments 1-3 for the requested workpapers.

b) Confirmed.

c) Confirmed.

d) Dimson's estimates are actually higher than those used by Concentric. As explained in Concentric's report, Exhibit M2, the historical MRPs for Canada and the U.S. are the values reported by Kroll, which publishes information on historical market returns and government bond yields. The Canadian data cover the period from 1919-2023, while the U.S. data are from 1926-2023. The historical MRP reported by Kroll is based on the annual return on large company stocks (i.e., the S&P 500 in the U.S. and the TSX in Canada) less the income-only return on 20-year government bonds, equal to 7.17% for the U.S. and 5.68% for Canada. The Dimson study cited by Dr. Cleary used a different time period than the Kroll data that Concentric relied upon (1900-2015, vs. 1919-2023). Dimson computes a real return on equities, inflation, and real bond returns over this period. If you add Dimson's real equity returns to inflation and subtract the real bond yields, all reported by Dimson, these estimates are higher than those used by Concentric from Kroll, resulting in an MRP of 8.8% in the U.S. and 8.5% in Canada.

e) Confirmed.

f) Confirmed as to the number of companies with growth rates. By Concentric's count, there are 222 companies listed on Exhibit CEA-6.1, meaning that 162 companies do not have a reported growth rate from Bloomberg.

g) Confirmed.

h) Concentric used the approach that has been adopted by the Federal Energy Regulatory Commission and several state utility regulators to calculate the forward-looking MRP, which is to compute the total return for the broad market (in this case, the TSX Index) using a Constant Growth DCF model and then to subtract the risk-free rate.

i) Confirmed. The U.S. calculations are provided in Exhibit CEA-6.2.

j) Not confirmed. The EPS growth rates for the S&P 500 companies range from 188.0% to -32.44%.

k) Concentric has considered whether the current short-term EPS projections for the S&P companies are sustainable over the longer-term. That is the main reason why Concentric did not rely on the forward-looking MRP for either Canada or the U.S. in its CAPM analysis. Rather, as stated in Concentric's report, Exhibit M2, Concentric's CAPM analysis uses the historical MRP from Kroll for Canada and the U.S.

l) The projected market returns for Canada and the U.S. reported in Dr. Cleary's evidence are not consistent with the historical returns that investors have earned in the TSX and S&P 500 indexes over the long-term. Concentric sees no reason to believe that future returns in equity markets will be substantially lower (i.e., in the range of 5.0% lower) than historical returns in both countries. Nevertheless, as explained in the response to subpart (k), Concentric has not used the forward-looking MRP in its CAPM analysis in this proceeding.

m) Concentric disregards the forward-looking MRP for the reason stated in subpart (k) above – that is, we have concerns with the level of short-term EPS growth rates for companies in the S&P 500 and TSX indexes and whether those growth rates are sustainable. Concentric has used the historical MRPs for Canada and the U.S., although we would observe that the level of government bond yields is somewhat lower than the historical average yields on government bonds used by Kroll to calculate the historical MRP. There is an inverse relationship between interest rates and the equity risk premium, which suggests that the historical MRPs from Kroll for Canada and the U.S. are likely somewhat understated given current expectations for government bond yields.

Ontario Energy Association (OEA)

Answer to Interrogatory from
Association of Major Power Consumers in Ontario (AMPCO) / Industrial Gas Users Association (IGUA)

INTERROGATORY

Reference:

On pages 66-68, Concentric discusses its beta estimates it uses in its CAPM Ke calculations.

On page 66, Concentric states that:

> "… empirical studies have provided evidence that an individual company beta is more likely than not to move toward the market mean of 1.0 over time." The study by Blume that Concentric references to support this assertion in footnote 77 is a 1970 article – 54 years old.

Evidence supporting the fact that utility betas do not gravitate towards one:

Michelfelder and Theodossiou (2013) show empirically that utility betas do not have a tendency to converge to 1.0 and concluded that the adjusted betas as reported by Value Line are not applicable for public utilities.

- As shown in Appendix B of Exhibit M4 herein (Dr. Cleary's evidence), Sikes (2022) provides a chart in Figure IV of his report that estimates betas for utilities over the 1970-2020 period (i.e., using over 50 years of observations) that leads Sikes to note (on page 48 of his report) that: "It is undeniable based on Figure IV that the Value Line Adjustment is inappropriate. Clearly, utility betas have been consistently below 1.0 and as shown in Exhibit H of the Appendix, the historical sample suggests an average of 0.55." In fact, the line depicting adjusted betas in Sikes' Figure IV is ALWAYS above the line depicting actual betas – which clearly shows that adjusted beta estimates are upwardly biased.

- Exhibit M4, Appendix B shows that over the historical raw Beta estimates for Canadian Utilities over the 1995-2019 period averaged 0.40 (weekly data) and 0.34 (monthly data), with maximums of 0.71 and 0.62 respectively and nowhere during this 25-year period did the Canadian Utility beta estimates even come close to 1.0.

- Exhibit M4, Appendix B shows that over the historical raw Beta estimates for U.S. Utilities over the 1995-2019 period averaged 0.49 (weekly data) and 0.42

(monthly data), with maximums of 0.84 and 0.85 respectively and nowhere during this 25-year period did the U.S. Utility beta estimates even come close to 1.0.

Question(s):

a) Please provide the Blume (1970) study referenced in footnote 77.

b) Please confirm that the Blume (1970) study referenced by Concentric examines beta estimates for a broad variety of industries and does not focus on one particular industry (including utility stocks). If not confirmed, please explain.

c) Given the evidence cited above that utility betas do not gravitate to one (or that utility sample averages never get close to one) please explain the rationale for Concentric's reliance on upwardly biased adjusted beta estimates.

d) Please provide all the associated raw "unadjusted" beta estimates for the beta estimates provided in Concentric's Exhibit CEA-7.3 for the Canadian and North American proxy groups, and recalculate Concentric's CAPM Ke estimates for all of the proxy groups as reported in Figure 18 (page 70) of Concentric's evidence using raw beta estimates. If Concentric is unable to locate the raw or unadjusted beta estimates from the initial data sources, please adjust the beta estimates using the formula:

$$\text{Raw Beta} = (\text{Adj. Beta} - 1/3)\times(3/2)$$

For example, the average adjusted beta of 0.84 for the Canadian proxy group would equate to a raw beta of 0.765 as calculated below:

$$\text{Raw Beta} = (0.84 - 0.33)(3/2) = 0.765$$

Please provide all supporting data and worksheets (in excel format), with all accompanying formulae.

Response:

a) Please see AMPCO/IGUA-9(a), Attachment 1 for the requested Blume study which is dated March 1971.

b) Confirmed.

c) Concentric does not agree with the characterization of the betas used in its analysis as "upwardly biased". See the response to N-M2-10-OEB Staff-13 (a) for further explanation and support for the use of adjusted betas, and note in response to (d) below, that the CAPM results using “raw” and “adjusted” betas are similar, as utility betas have increased toward 1.0, lessening the impact of the adjustment toward the market mean.

d) Please see the below, as well as AMPCO/IGUA-9(d), Attachment 1.

Proxy Group	Average MRP	Forward-looking MRP	Historical MRP
Canadian	10.86%	12.87%	8.85%
U.S. Electric	12.75%	15.11%	10.39%
U.S. Gas	11.44%	13.42%	9.46%
North American Electric	12.09%	14.30%	9.88%
North American Gas	11.58%	13.70%	9.47%
North American Combined	12.09%	14.30%	9.87%

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British Columbia Utilities Commission

Generic Cost of Capital Proceeding

(Stage 1)

Decision
and Order G-236-23

September 5, 2023

Before:
D. M. Morton, Panel Chair
A. K. Fung, KC, Commissioner
K. A. Keilty, Commissioner
T. A. Loski, Commissioner

narrowing the equity disparity with the gas proxy groups. But FortisBC states that this logic will no longer hold at the CEC's recommended 40 percent equity for FEI and applying a Hamada adjustment to Mr. Coyne's CAPM results for the North American gas proxy group at 40 percent equity would increase the estimated ROE for FEI by 48 bps to 10.78 percent.[717]

RCIA

With respect to RCIA's submission, FortisBC points out that RCIA arrives at its proposed ROEs of 8.00 percent to 8.75 percent for both FEI and FBC by ignoring the Multi-Stage DCF model (and the higher results[718]) altogether, by applying unsupported downward adjustments to Mr. Coyne's CAPM results, by ignoring the most current data, and by failing to account for differentials in financial risk and size premium. FortisBC submits that updating RCIA's own calculations to reflect October 2022 data alone significantly closes the gap with Mr. Coyne's recommendations, and rectifying other shortcomings brings them further into alignment.[719]

As explained in Section 5.2.5, with the first adjustment, RCIA's CAPM-based ROE would increase to 9.43 percent, which is significantly higher than its proposed 8.00 percent to 8.75 percent. Averaging this 9.43 percent with the Multi-Stage DCF model results for the Canadian proxy group of 10.46 percent based on October 2022 data would result in an ROE of 9.94 percent for both FEI and FBC. FortisBC submits that these values support Mr. Coyne's recommendations of 10.1 percent on 45 percent common equity for FEI and 10.0 percent on 40 percent common equity for FBC.[720] Then, applying a Hamada adjustment to RCIA's own CAPM calculations, updated to October 2022 data for the Canadian proxy group at 40 percent equity, would increase the estimated ROE for FEI and FBC by 47 bps to 9.90 percent.[721] And adding a size premium for FBC, which Mr. Coyne calculates at 105 bps based on Duff & Phelps data, would further increase the CAPM ROE for FBC.[722]

Overall Panel Determination on Capital Structure and ROE

Deemed Equity Component

FortisBC proposes an equity thickness of 45.0 percent for FEI and 40.0 percent for FBC, while interveners recommend 40.0 percent to 42.0 percent for FEI and 38.5 percent to 40.0 percent for FBC. Mr. Coyne observes that his recommended 45.0 percent equity ratio for FEI is the approximate midpoint between the average equity ratio of Canadian investor-owned gas distribution companies and US gas distribution companies.

While the Panel views the 37.0 percent to 53.4 percent equity thickness of comparable Canadian and US gas utilities (see Table 36 above) as a possible range of equity thickness for FEI, this does not imply that any point within the range will meet the Fair Return Standard. The Panel is not convinced that determining a deemed equity component can be done in a precise manner such as taking an average between certain numbers. A capital structure that is optimal for FEI or FBC may not be optimal for other utilities. The Panel must assess the business risk, financial risk, and other items such as accounting for differences in leverage in the proxy group

[717] FortisBC Reply Argument, pp. 43–44.

[718] The Multi-Stage DCF model results are higher than the CAPM results based on October 2022 data, not December 2021 data.

[719] FortisBC Reply Argument, p. 47.

[720] FortisBC Reply Argument, pp. 50–51.

[721] 9.43% + 0.47% = 9.90%.

[722] FortisBC Reply Argument, p. 51.

companies used in the modelling (e.g. a Hamada adjustment in the CAPM results) and allowing for financial flexibility, all of which may be difficult to quantify when estimating the required equity component.

Further, Mr. Coyne's "midpoint" observation does not align with his recommendation for FBC's deemed equity ratio of 40.0 percent, where the Canadian electric average is 39.42 percent and the US electric proxy group average is 49.76 percent as shown in Table 37 above.

Throughout this decision, the Panel notes that certain factors should be considered as part of the capital structure determination, namely:

- Compensation to the shareholder for the business and financial risks of FEI and FBC (Sections 4.2 and 4.3).
- The approach to addressing the discrepancy in financial risk through an adjustment to the capital structure (Section 5.2.2).
- Consideration of financial flexibility to the extent that it is required for FEI and FBC to have spare borrowing capacity. However, Mr. Coyne submits that financial flexibility is not necessary if the regulator establishes comparable equity ratios in the 50 percent to 52 percent range and comparable ROEs in the 9.5 percent to 10.0 percent range (Section 6.2.2).
- Benefits of maintaining the current credit ratings of FEI and FBC (Section 4.1).

In Section 4 of this decision, we assess how business risk has changed since 2016 for FEI and 2013 for FBC from the perspective of their shareholder and investors. We discuss that Energy Transition risk for FEI is a real shareholder risk in Section 4.2, while other increased risk categories are largely borne by ratepayers. Overall, an increase in FEI's equity component is warranted to compensate for the increased risks faced by FEI's shareholder and investors.

The Panel recognizes that Dr. Lesser describes business risks to be generally reflected in the determination of the allowed ROE because financial risks are most directly related to a firm's capital structure, credit rating, and cost of debt. However, there is no supporting evidence for his view. In contrast, Mr. Coyne's view is that there is a need to adjust either the capital structure or the ROE. Therefore, it follows that regulators must consider capital structure and cost of common equity together to determine whether the Fair Return Standard has been met.

For practical reasons, given the inter-relationship of all these factors, the Panel will continue the approach of reflecting changes in business risks as adjustments to the capital structure, recognizing that it will also impact the ROE. This approach is consistent with past BCUC decisions and provides room for the exercise of informed judgment.

In determining the optimal capital structure for FEI, the only expert evidence is Mr. Coyne's recommendation of 45.0 percent and his cost of capital analysis is largely built around this 45.0 percent equity thickness. Further, Mr. Coyne chooses not to make Hamada adjustments to his own CAPM results because his recommended common equity ratio of 45.0 percent for FEI would "significantly narrow the equity disparity with the gas proxy group."[723] The Panel agrees that any deviation from a 45.0 percent equity thickness, for example, setting FEI's equity thickness at the 40.0 percent to 42.0 percent range, may warrant a corresponding impact on the allowed ROE.

In the absence of contrary expert evidence and recognizing that FEI shareholder's real business risks, such as the impacts from the Energy Transition risk have increased since 2016, we accept Mr. Coyne's recommended 45.0 percent equity thickness for FEI. The Panel finds that the 45.0 percent equity thickness meets the comparable investment and capital attraction requirements in the Fair Return Standard because 45.0 percent is premised on FEI's proxy group and supported by our assessment of FEI's business risk. Further, as compared to FEI's current 38.5 percent equity thickness, an increase to 45.0 percent will maintain FEI's financial integrity.

The Panel now turns to financial leverage and financial flexibility. The Hamada adjustment and financial flexibility are partially related. The objective is to harmonize FEI and FBC's financial leverage to be comparable with peer proxy companies. For FEI, we acknowledge that 45.0 percent meets the Fair Return Standard and is supported by business risk assessment, comparable investments, and expert recommendation. In our view, a 45.0 percent equity component forms an optimal capital structure based on the evidence in Stage 1.

Further, since FortisBC's own expert acknowledges that 45.0 percent would "significantly narrow" the equity disparity and bring FEI's equity thickness towards the 50.0 percent to 52.0 percent range applicable to its proxy group, the Panel is not persuaded that increasing FEI's equity thickness beyond 45.0 percent to incorporate a further adjustment for financial flexibility or ring-fencing is required in order to meet the Fair Return Standard. Therefore, **the Panel determines that the deemed equity component for FEI is 45.0 percent.**

For FBC, we note that FortisBC's proposed 40.0 percent equity thickness and interveners' positions are mostly aligned. Mr. Coyne also recommends 40.0 percent equity thickness for FBC. However, ICG submits that the BCUC should set FBC's equity thickness at 38.5 percent, which is based on the Canadian Electric median of 38.75 percent and submits that FBC's business risks are lower since 2013.[724] The Panel agrees with FortisBC that ICG's final arguments are unclear because on one hand, ICG submits that "the BCUC should place the greatest weight on the North American proxy group results"[725] but on the other hand, "the US proxy group should be no weight when determining FBC's equity ratio."[726] Therefore, we place no weight on ICG's recommendation to set FBC's deemed equity thickness at 38.5 percent.

As discussed in Section 4.3, the Panel finds that FBC's business risk overall has not changed materially since 2013. The Panel views that business risk assessment of FBC should be the primary factor to the determination of a fair capital structure. This is because we see that financial impacts, in part, result from our decision on the deemed capital structure. FBC has managed to maintain its current credit rating since 2013 at 40.0 percent equity thickness. Therefore, we find that no change in FBC's equity component within its current capital structure is warranted to reflect no material changes in its business risk.

Notwithstanding these findings, the Panel now needs to consider financial leverage and financial flexibility for FBC to determine whether any upward adjustment to its 40.0 percent equity thickness is warranted. FortisBC

[723] FortisBC Reply Argument, p. 43.
[724] ICG Final Argument, pp. 3–4.
[725] Ibid., p. 10.
[726] Ibid., p. 16.

and Mr. Coyne are not recommending any capital structure changes for FBC and have not explicitly recommended a size premium in the CAPM analysis for FBC.

While 40.0 percent equity thickness is in line with the Canadian electric utility average of 39.42 percent, it is much lower than the US electric proxy group average of 49.76 percent. We accept Mr. Coyne's observation that his FBC recommendation is in line with FBC's current risk profile, but not within the range of its US peers. In light of our decision to consider financial leverage and financial flexibility in the capital structure, we find that a modest upward adjustment in equity thickness of 1.0 percent for FBC is warranted to conform with the Fair Return Standard. Therefore, **the Panel determines that the deemed equity component for FBC is 41.0 percent.**

Return on Equity

The Panel is persuaded by Dr. Lesser's view that, in addition to being anchored in financial theory and being transparent, models used by regulators to set the cost of capital for regulated utilities should ideally minimize reliance on subjective factors. Dr. Lesser states that 'subjective' adjustments to model results are those made without any underlying basis in financial theory and no empirical support, and he advises against these types of adjustments, as they can undermine confidence that the resulting allowed ROE values are 1) just and reasonable and 2) consistent with reasonable decision-making.

Previously in this decision, the Panel made certain determinations that are departures from, namely the 2013 and 2016 BCUC cost of capital decisions. One change worth highlighting is the Panel's determination to use North American proxy groups, based on a finding that using North American data, consisting of a reasonable mix of both Canadian and US comparators, is superior to using either Canadian proxy groups or US proxy groups alone.

Furthermore, the Panel accepts Mr. Coyne's beta estimates, which are Blume-adjusted, noting that both experts in this proceeding favour the use of Blume-adjusted betas and that none of the parties object to their use. The Panel is also reassured to see that empirical evidence exists to show that the Blume adjustment is applicable to all betas, ranging from a low of 0.50 to a high of 1.53. The Panel recognizes that the use of Blume-adjusted betas is a departure from the previous two BCUC cost of capital decisions and has the effect of increasing the CAPM ROE as the Blume-adjusted betas for Mr. Coyne's North American proxy group average 0.86, compared to a BCUC-accepted beta of 0.60 in the 2013 and 2016 Decisions.

Also, the Panel finds that it is appropriate to consider forward-looking estimates in determining the MRP and to base that forward-looking MRP on the Constant DCF model, which has been given equal weighting to the historical MRP. These determinations are also departures from previous BCUC decisions. In particular, the 2016 Decision placed more weight on historical MRP estimates than on the forward-looking ones and no weight on the DCF estimates of the forward-looking MRP (constant growth or Multi-Stage DCF). The Panel acknowledges that these determinations also increase the CAPM ROE relative to placing more weight on historical MRP or to using the Multi-Stage DCF model to estimate the forward-looking MRP.

Beyond these findings, the Panel takes the approach of making determinations that have a sound basis in financial theory, that are transparent and easily replicated, with minimal 'subjective' adjustments. The Panel agrees with Dr. Lesser and finds it preferable to get the allowed ROE value right based on the models rather than adjusting the allowed ROE after the fact, such as adding adders for financial flexibility and flotation costs or considering other adjustments as suggested by some interveners.

To balance the fact that pure market-based models like the DCF model and CAPM tend to get whipsawed by volatile conditions in the market, which characterized much of the period during which evidence was filed in this proceeding, the Panel finds that relying on more models than just the CAPM and Multi-Stage DCF is especially important. Accordingly, the Panel determined earlier in this decision that considerable weight should also be given to the use of the Risk Premium Model, instead of simply using it as a reasonableness check as Mr. Coyne advocates.

Ultimately, the Panel finds that assigning an equal weighting to each of the three models is appropriate for the following reasons: 1) the Panel sees merit in all three models, recognizing their respective strengths and weaknesses, and behaviour under different market conditions; 2) the Panel would be hard pressed to say that one model is fundamentally superior to the others; and 3) the Panel sees no compelling reason to give anything other than equal weighting to each of the three models.

The following table summarizes the Panel's previous individual determinations related to the ROE estimates based on the CAPM, Multi-Stage DCF model, Risk Premium Model, and the flotation costs and financial flexibility adders to arrive at its ROE determination for FEI and FBC, respectively.

Table 40: Allowed ROE for FEI and FBC

Models	Revised North American Gas Proxy Group	Revised North American Electric Proxy Group
CAPM – excluding flotation costs and financial flexibility adder (see Section 5.2.5)	9.90%	9.77%
Multi-Stage DCF model – excluding flotation costs and financial flexibility adder (see Section 5.3.3)	8.93%	8.99%
Flotation costs and financial flexibility adders for the CAPM and Multi-Stage DCF models only (see Section 6.2)	0.00%	0.00%
Risk Premium Model (see Section 5.4.3)	10.12%	10.16%
Average of all three models	**9.65%**	**9.64%**

From a purely mathematical standpoint, FEI would have an allowed ROE that is 1 bps higher than FBC. However, the Panel does not view that such differentiation in allowed ROE is warranted. The difference in utility characteristics is already reflected in the deemed capital structure for FEI and FBC. **The Panel finds that an allowed ROE of 9.65 percent for each of FEI and FBC will meet the Fair Return Standard based on the evidence examined and submissions received in Stage 1.**

For the reasons stated above, the Panel determines the following:

- **For FEI, a deemed equity component of 45.0 percent and an allowed ROE of 9.65 percent; and**
- **For FBC, a deemed equity component of 41.0 percent and an allowed ROE of 9.65 percent.**

Although the allowed ROEs for both utilities are determined to be the same for FEI and FBC, the Panel notes that the reasoning behind the utilities' overall cost of capital determinations are fundamentally different. As a natural gas distribution utility, FEI's shareholder and investors are faced with higher business risk driven primarily by the Energy Transition. Hence, FEI's deemed equity component is higher than that of FBC. In contrast, while the Panel finds that FBC's business risks are similar since it was last reviewed, FBC is a relatively small utility with weaker financial metrics. Lastly, the financial models using the most recent October 2022 data and the appropriate proxy groups yielded very similar ROE results for both FEI and FBC.

FortisBC and Mr. Coyne introduce the weighted ROE concept, and the table below is a compilation of weighted ROEs presented by the parties compared to the Panel's decision.

Table 41: Comparison of Weighted ROEs for FEI and FBC

	FEI	FBC
Existing	3.37%	3.66%
Proposed	4.55%	4.00%
Canadian Average	3.23%	3.45%
U.S. Average	4.93%	4.72%
Proposed by interveners	3.20-3.99%	3.20-3.82%
Decision	9.65% * 45.0% = 4.34%	9.65% * 41.0% = 3.96%

Our decision falls within the range between the Canadian and US averages, as well as almost exactly halfway between the high-end of the interveners' recommendations and FortisBC's proposal. As explained in the reasons above, we find that the deemed equity thickness and allowed ROEs for each of FEI and FBC meet the Fair Return Standard. The Panel expects that our decision will fairly compensate investors' opportunity cost, maintain financial integrity of the utilities, and enable each utility to continue to attract new capital upon reasonable terms.

7.0 EFFECTIVE DATES AND STAGE 2 OF THE GCOC PROCEEDING

Having made our determinations on FEI and FBC's respective cost of capital, we now examine the appropriate timeline for the changes to come into effect. FEI and FBC currently have interim rates in place, effective January 1, 2023.[727] The BCUC invited parties to address the following:[728]

1. The effective dates for which FEI and FBC's cost of capital will take effect and the rationale; and
2. The timing and process to commence Stage 2.

The BCUC also invited further submissions on the effective date for all other utilities that use the Benchmark Utility to set their own cost of capital.[729]

[727] FEI Annual Review for 2023 Delivery Rates, Decision and Order G-352-22 dated December 5, 2022; FBC Application for Reconsideration and Variance of Order G-382-22, Decision and Order G-87-23 dated April 19, 2023.
[728] Exhibit A-26.
[729] Exhibit A-31.

Alberta Utilities Commission

Determination of the Cost-of-Capital Parameters in 2024 and Beyond

October 9, 2023

Alberta Utilities Commission
Calgary, Alberta

Determination of the Cost-of-Capital Parameters in 2024 and Beyond | **Decision 27084-D02-2023**
Proceeding 27084

1 Decision summary

1. In this generic cost of capital (GCOC) decision, the Alberta Utilities Commission adopts a formulaic approach, utilizing the equity risk premium (ERP) methodology, to calculate the fair rate of return on equity (ROE) for Alberta's electric and gas utilities in 2024 and beyond. The Commission has determined that the ROE resulting from the formulaic approach will uniformly apply to all of the utilities.

2. This decision also outlines the approved deemed equity ratios (sometimes referred to by parties as "equity thickness"; collectively, the ROE and equity ratios, are referred to as "cost-of-capital parameters") for the utilities on a final basis. Specifically, accounting for differences in the risk of each of the utilities, the Commission has determined that no change is required to the deemed equity ratios approved in the 2018 GCOC decision.[1]

3. The Commission institutes a mandatory review of cost-of-capital parameters every five years, subject to mid-term reopeners either at its own discretion or upon application from interested parties. The established cost-of-capital parameters will apply to the following utilities:

- AltaLink Management Ltd.
- Apex Utilities Inc.
- ATCO Electric Ltd.
- ATCO Gas and Pipelines Ltd.
- ENMAX Power Corporation
- EPCOR Distribution & Transmission Inc.
- FortisAlberta Inc.
- KainaiLink L.P.
- City of Lethbridge
- PiikaniLink L.P.
- The City of Red Deer
- TransAlta Corporation

4. The Commission's decision to implement the formulaic approach for ROE determination is driven by a commitment to reduce regulatory lag and regulatory burden, enhance transparency, and deliver regulatory certainty, while balancing the interests of all stakeholders. This approach is a significant step for GCOC proceedings towards a more efficient, predictable and cost-effective regulatory process that ultimately benefits ratepayers, utilities and the broader public interest in Alberta.

[1] Decision 22570-D01-2018: 2018 Generic Cost of Capital, Proceeding 22570, August 2, 2018.

5. The Commission approves the following formulaic approach to determine the ROE in 2024 and subsequent years:

$$ROE_t = 9.0\% + 0.5 \times (\text{YLD}_t - 3.10\%) + 0.5 \times (\text{SPRD}_t - \text{SPRD}_{base})$$[2]

6. That is, in each year, the approved ROE will be determined by adjusting the notional ROE of 9.0 per cent approved in this decision by the difference in forecast long-term Government of Canada (GoC) bond yield (YLD_t) and utility bond yield spread ($SPRD_t$) from their base values of 3.10 per cent and the bond yield spread for the month of February 2023, respectively. These forecasts will be calculated by the Commission in early November of each year as follows:

(i) The forecast long-term GoC bond yield will be calculated as the weighted average of (a) the 30-year GoC bond yield forecasts published by Royal Bank of Canada (RBC), TD Bank (TD) and Scotiabank in October, or the most recent month prior to October, preceding the test year for the forecast period spanning from Q1 to Q4 of the test year (0.75 weight); and (b) the naïve forecast[3] representing the average long-term GoC bond yield[4] over the period October 1 to October 31 each year preceding the test year (0.25 weight). In other words, the published forecasts and actual data in October 2023 will be used to set the ROE for 2024, data from October 2024 will be used to set the ROE for 2025, and so on.

(ii) The prevailing utility bond yield spread will be calculated as the average difference between the 30-year A-rated Canadian utility bond yield[5] and the long-term GoC bond yield[6] over the period October 1 to October 31 of each year preceding the test year (i.e., the utility bond yield spread in October 2023 will be used to determine the ROE for 2024, and so on).

7. The cost-of-capital parameters for the various investor-owned water utilities under the Commission's jurisdiction were not determined in this proceeding. However, the determinations in this proceeding may be considered in other proceedings should issues respecting ROE and deemed equity ratios arise for these utilities.

2 Background and procedural summary

8. On January 3, 2022, the Commission established a bifurcated process for this proceeding with the goal of determining ROE and deemed equity ratios. The first part of the proceeding (Stage 1) established the cost-of-capital parameters for 2023 and was completed on March 31, 2022, with the release of Decision 27084-D01-2022.[7] This decision addresses the second part of the proceeding (Stage 2), establishes a formulaic approach for setting ROE in 2024 and each year

2 The Commission has determined that it will use the bond yield spread for the month of February 2023, using the method set out in Section 6.5.3 of this decision.
3 A "naïve forecast" is a forecasting method that uses actual values from a previous period.
4 Bank of Canada CANSIM Series V39056.
5 Bloomberg Series C29530Y.
6 Bank of Canada CANSIM Series V39056.
7 Decision 27084-D01-2022: 2023 Generic Cost of Capital, Proceeding 27084, March 31, 2022.

thereafter, and sets the deemed equity ratios for the utilities. More specifically, the scope of Stage 2 comprised the following key objectives:

- Explore potential formula-based approaches for determining the ROE and identify a preferred formulaic method. This approach was intended to enhance transparency and predictability, ultimately saving both customers and Alberta utilities significant time, resources and costs associated with conducting fully litigated proceedings every one to three years.
- Establish the initial numerical variables required for the formula. This included defining an initial base, or notional ROE, that would form an integral part of the formula and serve as the basis for determining the ROE for the 2024 and future test years.
- Delineate the process for calculating the ROE in future test years while ensuring clarity and consistency in the methodology.
- Identify future processes or thresholds that would trigger a review of the formulaic approach and any necessary adjustments by the Commission, should such adjustments be deemed necessary.
- Evaluate whether the Commission should revise deemed equity ratios while employing a formulaic approach to determining the ROE.

9. By pursuing these objectives, the Commission aimed to provide a more structured and efficient framework for determining ROE and related parameters for 2024 and beyond.

10. Each of the utilities, except Lethbridge, Red Deer, TransAlta, KainaiLink L.P. and PiikaniLink L.P., actively participated in this proceeding. ATCO Electric and ATCO Gas (ATCO Utilities), Apex and Fortis co-sponsored the evidence of Dr. Bente Villadsen and Frank Graves. Apex also sponsored the stand-alone evidence of Michael Tolleth. AltaLink and EPCOR co-sponsored the evidence of Dylan D’Ascendis. ENMAX sponsored the evidence of Concentric Energy Advisors, Inc. (James Coyne and John Trogonoski) and Nicole Martin. Additionally, each of Apex, Fortis and the ATCO Utilities filed company-specific evidence.

11. The Consumers’ Coalition of Alberta (CCA), the Office of the Utilities Consumer Advocate (UCA), and the Industrial Power Consumers Association of Alberta (IPCAA) (collectively, the interveners or customer groups) also actively participated in the proceeding. The CCA sponsored the evidence of Jan Thygesen; the UCA sponsored the evidence of Dr. Sean Cleary and Russ Bell; and IPCAA sponsored the evidence of Dustin Madsen.

12. To assist with the development of a comprehensive record and to prevent prolonged and unproductive debates among the parties regarding the suitability of various utility comparator groups used to construct models for estimating the fair ROE for Alberta utilities, the Commission took a proactive approach. At the outset of Stage 2 of the proceeding, on October 14, 2022, the Commission organized a technical conference for parties (involving participants from utilities and customer groups) with the primary purpose to discuss and formulate a comparator group of representative utilities that would inform the data-driven analysis required to specify the initial numerical variables of a formula-based approach to setting the ROE.

13. The outcome of the discussions during the technical conference was documented in appendixes A and B of the Commission's letter, dated October 24, 2022,[8] which captured the consensus among parties regarding the Commission's proposed screening criteria for determining a comparator group. The appendixes also highlighted other areas where consensus was achieved or, in some instances, where consensus was not achieved. While agreement was reached on the majority of topics discussed at the technical conference, some matters still required further input from all parties. These additional submissions were subsequently received by the Commission on November 2, 2022.

14. On November 10, 2022, the Commission issued its determinations on the unresolved matters and, using the approved screening criteria, produced the list of comparator utilities. The Commission also circulated to parties a preliminary list of issues to be considered in this proceeding and provided parties the opportunity to highlight any material issues they believed the Commission should consider in Stage 2 of this proceeding that had not been identified in the list. Based on parties' feedback, a finalized issues list for Stage 2 of this proceeding was released on November 29, 2022, which parties used as a foundation for their evidentiary submissions.

15. In addition to having parties file evidence, the Commission's processes included information requests (IRs) and responses to evidence filed and/or sponsored by the utilities; IRs and responses to evidence sponsored by the interveners; concurrent rebuttal evidence filed by the utilities and interveners; and a one-week virtual oral hearing. The Commission also established a process for simultaneous written argument and reply argument. The Commission considers that the record of this proceeding closed with the filing of reply arguments on July 11, 2023.

16. The Commission reviewed the entire record in coming to this decision; lack of reference to a matter addressed in the evidence and submissions does not mean that the Commission did not consider it.

3 Fair return standard

17. The legislation that governs the Commission requires that it fix just and reasonable rates for the utilities it regulates.[9] The Commission is guided in this task by well-developed case law on the meaning of just and reasonable rates, which includes determining a fair return on the equity component of invested capital, or the fair return standard. These concepts are set out in three seminal decisions: the Supreme Court of Canada's decision in *Northwestern Utilities v Edmonton (City),*[10] and two cases from the Supreme Court of the United States, *Bluefield*

[8] Exhibit 27084-X0239.01.

[9] See Section 89 of the *Public Utilities Act;* Section 36(a) of the *Gas Utilities Act;* and Section 121(2)(a) of the *Electric Utilities Act.* Note that the *Electric Utilities Act* also requires the Commission to provide an owner of an electric utility with a reasonable opportunity to recover a fair return on the equity of shareholders of the electric utility as it relates to the investment (Section 122(1)(a)(iv)). The *Gas Utilities Act* and the *Public Utilities Act* requires the Commission to fix a fair return on the rate base (Section 37(1)). The Commission considers these statutory requirements to be the same.

[10] *Northwestern Utilities v Edmonton (City)* [1929] SCR 186 (*Northwestern Utilities*).

7 Capital structure

7.1 Overview, approved deemed equity ratios for 2024, and review timeframe

202. To satisfy the fair return standard, the Commission is required to determine a fair return on the deemed equity component of invested capital. In this section, the Commission will determine the deemed equity ratios (also referred to as capital structure) – that is, the approved deemed portion (percentage) of rate base, net of no-cost capital, supported by common equity, for each of the utilities.

203. In this decision, the Commission maintains its previous approach of setting a uniform approved ROE, and then adjusting for any differences in risk among each of the utilities by adjusting the deemed equity ratios. The Commission will make adjustments, if required, to recognize changes in relative risk for each utility from the deemed equity ratios approved for 2023 in Decision 27084-D01-2022.

204. The Commission finds that no change is required to the deemed equity ratios set out in the 2018 GCOC decision. The Commission has determined that a deemed equity ratio of 37 per cent for both distribution and transmission utilities (with the exception of Apex, whose deemed equity ratio will remain at 39 per cent), including those which pay income tax and those which currently are income tax exempt or do not currently pay income tax, satisfies the fair return standard when combined with a 9.0 per cent approved notional ROE, and will enable the utilities to target a credit rating in the A-range.

205. The Commission considers that the deemed equity ratios should be reviewed every five years, or whenever the ROE formula is reviewed, whichever happens first, and finds that this promotes regulatory efficiency. In the case of any material changes in business risk that occur before the scheduled review of the deemed equity ratios approved in this decision, parties can request that the Commission undertake an earlier review as further described in Section 5.5.

206. The section is organized as follows. In Section 7.2, the Commission briefly outlines the deemed equity ratios recommended by the parties. In Section 7.3, the Commission addresses the targeting of credit ratings in the A-range. In Section 7.4, the Commission discusses credit metrics required by a typical pure-play regulated utility in Canada in order to achieve an A-range credit rating. The Commission also evaluates the credit metrics of the utilities having regard to significant financial parameters observed in Rule 005 filings and other evidence on the record of this proceeding, including the embedded average debt rate, depreciation as a percentage of invested capital, the income tax rate and the mid-year construction work in progress (CWIP) as a percentage of invested capital.

207. The Commission's consideration of the other factors relevant to the determination of an approved deemed equity ratio for each utility is in Section 7.5 with a review of the evidence in relation to changes in business risk that impact all the utilities. The Commission addresses the submissions of Fortis and Apex regarding their deemed equity ratios in Section 7.6.

7.2 Requested deemed equity ratios

208. The currently approved deemed equity ratios and the ratios recommended by parties for 2024 are set out in the following table.

Table 7. Currently approved deemed equity ratios and the deemed equity ratios recommended for 2024

	Last approved[208]	Recommended by Apex/ATCO Utilities/Fortis[209] Dr. Villadsen	Recommended by AltaLink/ EPCOR[210] D. D'Ascendis	Recommended by ENMAX[211] J. Coyne	Recommended by IPCAA[212] D. Madsen	Recommended by the UCA[213] Dr. Cleary
Electricity and natural gas transmission						
AltaLink	37		40		35	37
ATCO Electric Transmission	37	42			35	37
ATCO Pipelines	37	40				37
ENMAX Transmission	37			40	35	37
EPCOR Transmission	37		40		35	37
KainaiLink L.P.	37					
Lethbridge	37					
PiikaniLink L.P.	37					
Red Deer	37					
TransAlta	37					
Electricity and natural gas distribution						
Apex	39	44				39
ATCO Electric Distribution	37	40			35	37
ATCO Gas	37	40				37
ENMAX Distribution	37			40	35	37
EPCOR Distribution	37		40		35	37
Fortis	37	43			35	37

209. Dr. Villadsen conducted a credit ratio analysis to determine at what approved ROE and equity ratio combination the ATCO Utilities, Fortis and Apex would meet standard credit metric benchmarks from credit rating agencies such as the earnings before interest and taxes (EBIT) coverage, funds from operations (FFO) coverage, and FFO to debt metric. She also looked at DBRS and Moody's stated debt to rate base benchmarks in recommending a deemed equity percentage of about 40 per cent for ATCO Electric Distribution, ATCO Gas, ATCO Pipelines, and Fortis. She noted that F. Graves further recommended an "about 300 [bps] of equity percentage" increase in the equity ratio of Fortis, and Dr. Villadsen adopted that recommendation. Dr. Villadsen noted that at a 10 per cent ROE, ATCO Electric Transmission only met the FFO coverage and FFO to debt metric at about 42.5 per cent equity, so she recommended a deemed equity ratio of about 42 per cent equity for ATCO Electric Transmission.

208 Decision 27084-D01-2022, paragraph 59.
209 Exhibit 27084-X0469.01, PDF pages 104-105. Dr. Villadsen concurred with M. Tolleth that the deemed equity ratio for Apex be at least 400 basis points higher than the other utilities. Exhibit 27084-X0921, PDF page 2. Exhibit 27084-X0925, PDF page 17. Exhibit 27084-X0930, PDF page 20.
210 Exhibit 27084-X0390, PDF page 133. Exhibit 27084-X0928, PDF page 32.
211 Exhibit 27084-X0315, PDF page 19. Exhibit 27084-X0924, PDF page 32.
212 Exhibit 27084-X0292, PDF page 6. Exhibit 27084-X0918, PDF page 31.
213 Exhibit 27084-X0320.02, PDF page 6. Exhibit 27084-X0926, PDF page 34.

For Apex, Dr. Villadsen recommended an equity percentage at least 400 basis points higher than the benchmark based on the business risk analysis by M. Tolleth.[214]

210. Dr. Villadsen benchmarked her recommended deemed equity ratios against deemed equity ratios approved by other Canadian regulators, noting that the OEB approved a deemed equity ratio of 40 per cent for electric distributors and 36 to 40 per cent for gas distributors, while the British Columbia Utilities Commission has approved equity ratios of 38.5 per cent or more, and the Régie de l'énergie du Québec has approved equity ratios of between 38.5 and 46 per cent.[215] In the U.S., the average equity ratios in 2021-2022 for electric and gas distribution utilities were 50.2 and 51.1 per cent, respectively.[216]

211. M. Tolleth concluded that in order to satisfy the fair return standard, Apex's deemed equity ratio should be set at a premium to that of the generic benchmark gas distribution utility, in recognition of the higher market cost of capital associated with its small size and correspondingly elevated risk. He further concluded that based on fundamental finance principles and market evidence, any partially countervailing reduction to Apex's deemed equity ratio for purposes of "balancing" the higher market cost of debt experienced by small utilities such as Apex would not be consistent with the fair return standard. M. Tolleth submitted that it would be appropriate for the Commission to set Apex's deemed equity ratio at least 400 basis points (bps) above that of the "generic" Alberta gas distribution utility.[217]

212. F. Graves submitted that it is clear that the REA issue faced by Fortis presents a material financial risk, and can be offset by either allowing an ROE increase of 68 bps for Fortis, or an increase of about 300 bps in the deemed equity ratio of Fortis.[218]

213. D. D'Ascendis recommended that the deemed equity ratio applicable to AltaLink and EPCOR should be 40 per cent, which he submitted reflects the substantial increase in market risk since the 2018 GCOC proceeding, and increased business risk faced by AltaLink and EPCOR over that same period.[219] D. D'Ascendis submitted that his 40 per cent recommendation is reasonable when viewed in light of the OEB's approved deemed equity ratio in its annual formula ROE.[220]

214. J. Coyne stated that his assessment showed that while Alberta regulated utilities generally have comparable business risk to companies in the North American proxy group, they have much higher financial risk. He added that the current deemed equity ratio for Alberta utilities is low by Canadian standards and very low when compared to U.S. utilities, and recommended that the Alberta deemed equity ratio be raised to at least 40 per cent. J. Coyne submitted that his recommended 40 per cent deemed equity ratio is the same as that currently allowed for Ontario's electric distribution companies, and equivalent to the Canadian average allowed equity ratio for investor-owned utilities. He commented that a 40 per cent deemed equity ratio is conservative for ENMAX, as it is a non-taxable entity that does not receive the benefit of including income taxes

214 Exhibit 27084-X0469.01, PDF pages 7-8.
215 Exhibit 27084-X0469.01, PDF page 101.
216 Exhibit 27084-X0469.01, PDF page 89.
217 Exhibit 27084-X0377, PDF pages 5-6.
218 Exhibit 27084-X0479, PDF page 47.
219 Exhibit 27084-X0390, PDF page 133.
220 Exhibit 27084-X0390, PDF page 10.

in its revenue requirement, thereby reducing its cash flow metrics as compared to taxable entities.[221]

215. D. Madsen recommended a two per cent reduction to the equity thickness for the electric transmission and electric distribution utilities, from 37 per cent to 35 per cent. He submitted that the business and regulatory risk of the electric utilities has improved since the 2018 GCOC proceeding and that the financial risks and performance of the utilities remains strong. D. Madsen added that the growth rates of the utilities have slowed significantly in recent years which, all else being equal, reduces risk.[222]

216. Dr. Cleary commented that Alberta utilities have low risk as shown by their consistent "low business risk" ratings, low earnings volatility, and most importantly, the ability to generate earned ROEs above the approved ROEs for the last 17 years. Dr. Cleary recommended no change in the approved deemed equity ratios but, rather, emphasized the impetus for a reduction in the approved ROE, based on his belief that it continues to be "well above the actual cost of equity for Alberta utilities." Dr. Cleary submitted that his recommendations are reasonable, and are supported by the credit metric analysis provided by R. Bell.[223]

217. R. Bell noted that if the achieved ROE increases, the level of the deemed equity ratio required to achieve the credit metric targets decreases. He recommended that if the approved ROE increases, the deemed equity ratio be decreased.[224]

7.3 Targeted credit ratings

218. The targeting of credit ratings in the A-range is one of the factors the Commission will continue to use as part of its determination of the deemed equity ratios for 2024 and beyond.

219. Credit ratings assess the credit worthiness of a firm as determined by a credit rating agency. A higher credit rating signals higher confidence in the firm's ability to meet its interest payments and to repay debt principal, allowing the company to borrow at a lower interest rate.

220. Historically, the Commission has recognized the importance of maintaining a target credit rating for the utilities in Alberta in the A-range,[225] and continues to do so. This target credit rating is especially important when interest rates rise. The use of the A-range credit rating target is a factor that respects the financial integrity, capital attraction and comparability aspects of the fair return standard.

221. The Commission finds that, generally, most utilities in Alberta have had little difficulty raising debt and equity financing on satisfactory terms since the 2018 GCOC proceeding, all while maintaining the credit ratings from S&P that were in place during the 2018 GCOC proceeding. The one exception is ENMAX's credit rating, which was decreased largely because of a debt-financed acquisition that was not associated with ENMAX's Alberta operations.[226]

[221] Exhibit 27084-X0315, PDF pages 4-5.
[222] Exhibit 27084-X0292, PDF page 62.
[223] Exhibit 27084-X0320.02, PDF pages 5-6.
[224] Exhibit 27084-X0318, PDF page 20.
[225] Decision 22570-D01-2018, PDF page 145, paragraph 689.
[226] Exhibit 27084-X0926, PDF page 26, citing Transcript, Volume 2, page 294, line 4 to page 296, line 1.

Ontario Energy Association (OEA)

Answer to Interrogatory from
Association of Major Power Consumers in Ontario (AMPCO) / Industrial Gas Users Association (IGUA)

INTERROGATORY

Reference:

On page 145, Concentric states (bold added for emphasis):

> *We **do not, however, see the benefit** of requiring utilities to file specific details regarding equity and debt issuances during each year. This would be both **administratively burdensome**, and beyond typical reporting requirements.*

Question(s):

a) Does Concentric agree that receipt of annual reports from utilities regarding debt and equity issues during the year would provide timely market-based information about Ontario utilities' ability to attract capital on favorable terms? If not, please explain why not?

b) Please explain why such reporting would be "administratively" burdensome to utilities.

c) Does Concentric agree with LEI that Ontario utilities do not typically have a large number of debt issues every year (and may have no new issues in some years)?

d) Does Concentric agree with LEI that utility equity issues are even less frequent occurrences than utility des issues, often with no new issues over several years?

e) Would utilities' financial teams have ready access to such information?

f) Would such information typically be included in annual financial reporting by the utility to its shareholder(s) and/or utility reports to potential investors?

Response:

a) These reports would provide evidence of the ability to attract capital, but in and of themselves, would provide limited value in determining the relative favorability of their terms, or the ability to attract all capital required. When Concentric analyzes similar debt and equity issuances, we collect data on all issues by utilities in a given period to put the specific utility's capital raise and terms in perspective. As explained by Concentric in response to N-M2-14-OEB Staff-23(a), we question whether collecting such data on Ontario utilities alone would provide value to the Board in determining whether the FRS continues to be met in relation to the additional filing requirement.

b) Any new reporting requirement creates an administrative burden on both the filing utility and the Board.

c) Concentric has not conducted comprehensive research, but as an example, EGI issues two to four debt instruments per year, with some years at zero, and other years up to 4 or 6.

d) Based on Concentric's experience, agreed.

e) Concentric assumes that each utility's treasury function would have access to such data.

f) It depends on the utility and its specific reporting. Details of debt and equity issuances are disclosed in Toronto Hydro's annual financial statements. EGI discloses of its debt issuance and retirement details in its annual financial statements as well but recognizes it may provide more detail than most utilities.

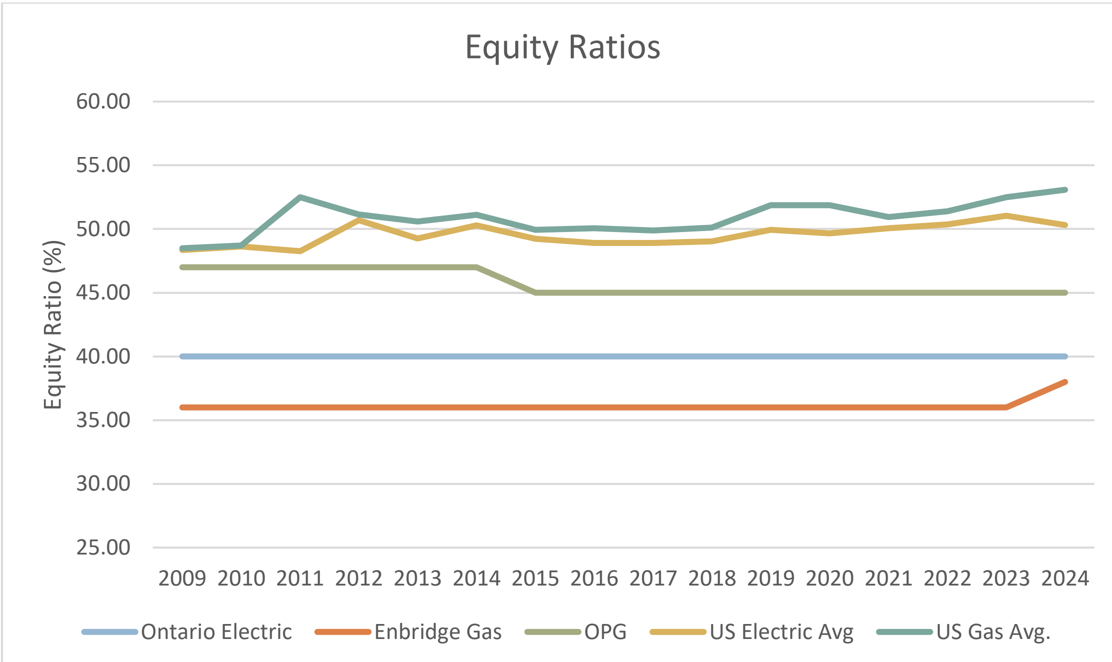
exposure to volumetric revenue risk, has a distinct risk profile that sets OPG apart from other Ontario utilities.

Independent of the risk ranking, however, Concentric is concerned that Ontario equity thicknesses, by being lower across the board than their U.S. peers, do not meet the Fair Return Standard. In the following sections, Concentric further discusses our recommendations regarding establishing equity thickness parameters in conjunction with the ROE in this proceeding that addresses that concern.

I. Analysis of Comparative Equity Ratios

The deemed equity ratios for Ontario's regulated electric distribution and transmission and gas distribution utilities are generally in line with the average equity ratios for their Canadian counterparts but well below the average level for U.S. electric and gas utilities. OPG has no direct peers, but it also falls below the average equity thickness levels for U.S. electric and gas utilities, despite its elevated level of risk. As shown in Figure 35 below, the deemed equity ratio for Ontario's electric distribution and transmission utilities of 40 percent is slightly lower than the Canadian average of 41 percent but substantially lower than the U.S. average of approximately 51 percent. The deemed equity ratio for OPG of 45 percent falls in between. Similarly, the deemed equity ratio for Enbridge Gas of 38 percent is slightly below the Canadian average of 39.9 percent (which includes the BCUC's recent increase to FortisBC Energy Inc.'s deemed equity ratio from 38.5 percent to 45.0 percent due primarily to risks associated with Energy Transition) and significantly lower than the U.S. average of slightly more than 52 percent. This gap in equity ratios with the U.S. means that Ontario's regulated utilities have substantially greater financial risk than their U.S. counterparts.

Figure 35: Deemed Equity Ratio in Ontario Compared to Canadian and US Averages – 2009-2024



Concentric also compared the deemed equity ratios for Ontario's electric and gas utilities to the actual and authorized equity ratio for the operating companies in the Canadian and U.S. proxy groups. The results of that analysis are summarized in Figure 36 below and shown in Exhibits CEA-10.1 through 10.6. This analysis demonstrates that the current deemed equity ratios are well below both the actual and authorized equity ratios for the operating utility companies in the U.S. Electric and U.S. Gas proxy groups. This is not consistent with the Fair Return Standard.

Figure 36: Actual and Deemed Equity Ratios for Proxy Groups

Proxy Group	Actual Equity Ratio	Deemed/Authorized Equity Ratio
U.S. Electric	52.30%	52.12%
U.S. Gas	53.85%	54.55%
Canadian	52.70% (US subs) 43.40% (Canadian subs)	51.69% (US subs) 40.30% (Canadian subs)

In light of these findings, Concentric recommends that the OEB's approach to setting the deemed capital structure should consider each particular utility company within the context of similarlysituated companies, for example, the proxy group companies, rather than being limited to requiring a demonstration of changes in business risk over time. Under the existing, latter approach, the OEB does not avail itself of all the necessary evidence to assess how the deemed capital structure for Ontario's regulated utilities compares to how other utility companies with comparable risk are capitalized, which in our view is necessary to meet the Fair Return Standard.

J. Deemed Equity Ratio Recommendation for the Ontario Utilities

The Fair Return Standard requires the OEB to set a return that (1) is sufficient for the utilities to maintain their financial integrity, (2) allows the utilities to attract equity and debt capital on reasonable terms, and (3) enables the utilities to compete for capital by offering a comparable return as investments of similar risk. Ontario equity thicknesses do not currently adhere to that standard.

Based on our analysis, we find that Ontario's regulated distribution and transmission utilities generally have comparable business risk to the companies in the North American Electric and Gas comparator groups. We also conclude that Ontario's utilities have similar financial risk to other electric and gas utilities in Canada and substantially greater financial risk than their U.S. peers due to the relatively low deemed equity ratios of 38 percent for Enbridge Gas, 40 percent for electric distribution and electric transmission, and 45 percent for OPG.

Given the unique characteristics of OPG, and, in particular, the fact that its regulated operations consist entirely of generating assets, it is not possible to find proxy companies that are perfectly comparable from a risk perspective. OPG's business risk, however, is considered to be higher than the proxy groups presented herein.

Given these findings, Concentric recommends the following with regard to equity thickness:

1. In the context of this generic cost of capital proceeding, and with a finding by the OEB that Ontario's regulated utilities have comparable business risk to the North American Electric and Gas proxy groups, the deemed equity ratios in Ontario are low compared to North American peers and therefore do not meet the Fair Return Standard. Ideally, the Ontario utilities should have a deemed equity ratio at parity with their U.S. counterparts, which is approximately 50-51 percent for electric utilities and 52 percent for gas distributors. In recognition of the regulatory principle of gradualism, however, an immediate move to parity with the U.S. would be abrupt. For that reason, we recommend that the OEB set a minimum

deemed equity ratio for Ontario utilities of 45 percent, which is at a point approximately halfway between the Ontario level and the U.S. average. That equity ratio would reflect progress towards parity for equity thickness among North American peers. Increasing the equity ratios for electric distributors and transmitters and Enbridge Gas would also reflect those industry segments' increased levels of risk. We also recommend increasing OPG's equity ratio in order to meet the Fair Return Standard, with a specific determination to be made by the OEB as part of OPG's next payment amounts proceeding taking into account the company's higher business risk relative to the proxy group.

2. In this proceeding, Concentric is not recommending individual utility changes to equity thickness. As discussed herein, there are factors that differentiate the risk levels among multiple segments of the industry, including OPG, single-asset transmitters, and Enbridge Gas As such, in addition to our recommendation of a minimum 45 percent equity ratio, we also recommend that each utility be authorized at its discretion to retain its current equity ratio and also have the ability to propose differences from the "generic" equity thickness in its rates application.

LEI's Recommendation and Concentric's Response

LEI recommends maintaining the OEB's current approach to determining the cost of capital, including the deemed capital structure, as, in LEI's view, it sufficiently considers investors' perspectives, i.e., the allowed cost is commensurate with the perceived risks associated with the sector, and meets the Fair Return Standard. LEI also recommends modification of interim reporting requirements to facilitate OEB's ongoing review of the utilities' cost of capital.

In Concentric's view, resetting the appropriate cost of capital and deemed equity thickness based on the methodologies described herein (i.e., DCF, CAPM, and Risk Premium models), along with consideration of financial, regulatory, and policy risks and an analysis of peer company equity ratios would ensure that the Fair Return Standard is met. The Fair Return Standard requires consideration of both changes in the utility's risk profile over time, as well as how the utility's business risk and deemed capital structure compares to the proxy group companies. Furthermore, commensurate returns and equity thickness set for the duration of the rate term, and reviewed every five years by the OEB, support relative regulatory predictability and the utility's financial stability.

Concentric does not support LEI's recommendation to modify annual reporting to include results of recent credit and equity issuances as this information would be retrospective for the prior year. Independently, these reports would not provide sufficient indication of future costs of capital or business risks on the horizon. Per the status quo, any utility facing a significant change requiring a re-evaluation by the OEB would provide evidence in its next rates application in which they would present the supporting evidence.

In Concentric's view, the OEB should rebase the authorized return on equity for Ontario's utilities based on current market data and set the deemed equity thickness for Ontario's utilities to better reflect the capital structure and business risk of Ontario utilities relative to the North American proxy group companies.

LEI's recommendation for utilities to include forward cash flow modeling and scenario analysis showing the impact on credit metrics to support significant changes in business and/or financial risks creates a methodology that is too rigid and limiting for supporting changes that may need custom approaches in the future, and also raises confidentiality concerns. Reliance solely on cash flow and its impact on credit metrics fails to incorporate the complexity and manner of risks considered by equity investors, especially in an evolving risk environment. It also does not consider the utility's competitiveness for capital relative to its peers.

K. Single Asset vs. Multiple Asset Transmitters

Issue #13: Should the OEB take a different approach for setting the capital structure for electricity transmitters depending on whether they are a single versus multiple asset transmitter?

The risk analysis provided in the prior sections is based on corporate entities holding multiple assets. In this proceeding, Concentric is not providing specific recommendations regarding differences in equity ratios for each utility, but rather is focused on a "generic" equity thickness that can then be modified in individual utility rates applications, as is currently permitted in Chapter 2.9 of the Filing Requirements For Electricity Transmission Applications.

In such a rates application, we expect that factors related to diversification of operations would be considered, among others. For example, Concentric notes that single-asset companies do not have under their jurisdiction. The BCUC explained its rationale for using a North American proxy group as follows:

> *For the reasons outlined above, we find the use of the Canadian proxy groups and US proxy groups alone to be inferior to that of using a North American proxy group which has a reasonable mix of both Canadian and US comparators, and the averaging of the results of these three groups to be a poor compromise. On balance, we find that having a proxy group of North American comparators trumps any jurisdictional or structural differences. In making this determination, we rely on the facts that financial and capital markets are highly integrated and that utility regulatory regimes in North America are sufficiently similar for the purpose of establishing a comparable ROE.*[57]

The recent BCUC decision is consistent with our view that equity investors and credit analysts consider the utility industry as a North American industry, with Canadian companies competing for capital with similar risk companies in both countries.

The AUC also recently developed a set of screening criteria for purposes of selecting a proxy group of companies that could be used to estimate the cost of equity for Alberta's electric and gas utilities.[58] The large majority of companies chosen by the AUC for the comparator group (28 out of 33 companies, or almost 85 percent) were either U.S. electric or U.S. gas utilities (or both). In addition, several of the Canadian companies in the AUC's comparator group have significant U.S. operations, including Emera, Fortis, and Algonquin Power. This highlights the extent to which the utility industry has clearly become a North American industry from an investor and allocation of capital viewpoint. Canadian regulators have increasingly accepted the use of U.S. data and proxy groups to estimate the allowed ROE for Canadian regulated utilities. Additionally, the development of a proxy group comprised entirely of Canadian utilities is challenged by the small number of publicly traded utilities in Canada and the fact that several of those Canadian companies derive a significant percentage of revenues and net income from operations other than regulated utility service.

4. Integration of Canadian and U.S. Capital Markets

The OEB considers the use of both U.S. and Canadian market and company data, as discussed above. It is also important, however, to consider the comparability of the risk environment from an investor's perspective, as risk drives return expectations. This is especially necessary in the Energy

57 British Columbia Utilities Commission, Decision and Order G-236-23, September 5, 2023, p. 16.
58 AUC Decision 27084-D02-2023, October 9, 2023, at para 99-104.

Transition, where investors will seek to optimize returns for a given level of risk taking. In a world of increasingly linked economies and capital markets, investors seek returns from a global basket of investment options. Investors distinguish between risks on a country-to-country basis, factoring in the comparability of the economic, business, regulatory and political environments.

Country-specific economic, business and political conditions that affect investment risk can be measured through a variety of qualitative and quantitative metrics. One such measure, produced by The Economist Intelligence Unit, rates Canada and the U.S. the same from an overall country risk perspective. Both are rated as A, with AAA being the highest rating.[59] The Economist provides the following description of its country risk ratings:

> *The Economist Intelligence Unit's Country Risk Service produces reports on 100 emerging markets and 20 OECD countries. These country-specific reports are complemented by this Risk ratings review, which analyses regional and global risk trends. The main focus of the ratings is on three risk categories to which clients can have direct exposure: sovereign risk, currency risk and banking sector risk. We also publish ratings for political risk and economic structure risk, as well as an overall country credit rating. The ratings are measured on a scale of 0-100. Higher scores indicate a higher level of risk. The scale is divided into ten overlapping bands: AAA, AA, A, BBB, BB, B, CCC, CC, C, D. In the Risk ratings review, ratings for a region are defined as the unweighted average of the ratings for all the countries being assessed in that region.*[60]

Figure 9 summarizes the country risk ratings for Canada and the U.S. as of August 2021.

[59] The Economist Intelligence Unit, Country Risk Service, Risk Ratings Review, August 2021, p. 30.
[60] Ibid, p. 28.

Figure 9: Country Risk Ratings

	Canada	U.S.
Sovereign Risk Rating	A	AA
Currency Risk Rating	A	A
Banking Sector Risk Rating	AA	A
Political Risk Rating	AAA	AA
Economic Structure Risk Rating	A	A
Overall Country Risk Rating	A	A

This suggests that from a country risk perspective, Canada and the U.S. are directly comparable. This assessment is confirmed in country risk reports from Allianz indicating that both Canada and the U.S. were ranked AA1 as of January 2024.[61]

The magnitude and significance of trade between the two countries reflects the high degree of integration between the two economies. According to the U.S. Department of State: "The United States and Canada enjoy the world's most comprehensive trading relationship, which supports millions of jobs in each country. Canada and the U.S. are each other's largest export markets, and Canada is the number one export market for more than 30 U.S. States."[62] Canada is currently the U.S.'s second largest goods trading partner overall with $773 billion in total (two way) goods trade during 2023.[63] Two-way trade averaged $US 2.1 billion per day in 2023 and during the first four months of 2024. This is an indication of the high degree of economic integration between the two economies.

Exhibit CEA-3 presents several measures of the overall economic and investment environment in Canada and the U.S. On balance, the economic and business environments of Canada and the U.S. are highly integrated and exhibit strong correlation across a variety of metrics, including GDP growth and government bond yields. From a business risk perspective, including overall business environment and competitiveness, Canada and the U.S. are ranked closely when compared against other developed and developing countries.

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61 Source: Country Risk Report Canada (allianz.com) , Country Risk Report United States (allianz.com).
62 U.S. Department of State, https://www.state.gov/u-s-relations-with-canada.
63 https://www.census.gov/foreign-trade/balance/c1220.html.

Based on these macroeconomic indicators, there are no fundamental dissimilarities between Canada and the U.S. (in terms of economic growth, inflation, or government bond yields) that would cause a reasonable investor to have a materially different return expectation for a group of comparable risk utilities in the two countries. Our cost of capital analysis is framed by the conclusion that Canada and the U.S. have comparable macroeconomic and investment environments. Importantly, this is not a new phenomenon or novel interpretation of the data. For instance, in 1977, the National Energy Board ("NEB", now the "CER") reached a similar conclusion when it found: "the opportunity cost of capital is not significantly different between Canada and the U.S." The NEB concluded: "Based upon its assessment of overall risk of the Company (IPL) relative to U.S. and Canadian industrials, the Board concludes that the cost of equity should be equal to, or slightly less than, the opportunity cost of investments in such (U.S.) companies."[64] Therefore, based on the factors discussed above, we consider both Canadian and U.S. proxy companies for our analysis without making an adjustment for differences in risk between the two countries.

D. Use of Multiple Methodologies to Estimate ROE

The cost of equity cannot be directly observed in the same way as the cost of debt or preferred stock. Analysts use multiple approaches to estimate the cost of common equity, including the DCF model, the CAPM, and the Risk Premium model. The required ROE can be estimated using one or more analytical techniques that rely on market-based data to quantify investor expectations regarding required equity returns, adjusted for certain incremental costs and risks. Quantitative models produce a range of results from which the market-required ROE is determined. A consideration in determining the ROE is to ensure that the methodologies employed reasonably reflect investors' *forward-looking* views of financial markets in general, and the subject company (in the context of the proxy groups) in particular.

No financial model can exactly pinpoint the "correct" ROE; rather, each test brings its own perspective and set of inputs that inform the estimate of the ROE. Consistent with the *Hope* standard, it is "the result reached, not the method employed, which is controlling."[65] Although each model brings a different perspective and adds depth to the analysis, each model also has its own inherent limitations and should not be relied upon individually without corroboration from other approaches.

64 National Energy Board, RH-2-76 Part II, PDF p. 144-145.
65 See Hope Natural Gas v. Federal Power Commission.

Ontario Energy Association (OEA)

Answer to Interrogatory from
Association of Major Power Consumers in Ontario (AMPCO) / Industrial Gas Users Association (IGUA)

INTERROGATORY

Reference:

On February 1, 2023, Concentric filed a report titled "Generic Cost of Capital for 2024 and Beyond" before the Alberta Utilities Commissions, on behalf of ENMAX Power Corporation (27084-X0315 2023-02-01 Appendix 1 - Evidence of Concentric Energy Advisors).

During the Alberta GCOC proceedings, Concentric recommended an allowed ROE of 9.5% and an allowed ER of 40%, as compared to its current recommendations for Ontario utilities of 10% and 45% respectively. Concentric made these recommendations in Alberta 17 months ago based on its acknowledgement on page 92 of its Alberta report that its recommendations at that time were based on bringing Alberta utilities in alignment with the deemed equity ratios of comparable-risk electric utilities in Ontario and elsewhere across Canada.

Question(s):

a) Figure 17 (page 48) of that report depicts Concentric's Canadian proxy group of utilities it relied upon during those proceedings. The group includes five utilities, including four of the six utilities included in its Canadian proxy group for the current proceedings (excluding AltaGas Limited and Enbridge Inc.) but also includes Algonquin Power and Utilities Corp. (which it also included in its Newfoundland November 2023 evidence). Please explain why Concentric did not include Algonquin Power in its current Canadian proxy group.

b) Please also explain why Concentric now decided to include AltaGas Limited in its Canadian proxy group, despite the position that Concentric took in the Alberta proceedings that AltaGas was not a reasonable Canadian comparator.

c) Please explain why Concentric now decided to include Enbridge Inc. in its Canadian proxy group, contrary to its exclusion by Concentric as a reasonable comparator during those proceedings.

d) Figure 18 (page 49) of Concentric's Alberta report depicts Concentric's U.S. Electric proxy group of utilities that it relied upon during those proceedings. The group of 22 utilities includes 11 of the 15 included in its U.S. Electric proxy group for the current proceedings but it excludes the following four utilities which are included in its U.S. Electric proxy group for the current proceedings; Exelon Corp., NextEra Energy Corporation, Pinnacle West Capital Corporation, and PPL Corporation. Please explain why Concentric chose to include these additional utilities in its current U.S. Electric proxy group, but did not include them in its Alberta evidence.

e) Figure 18 (page 49) of Concentric's Alberta report also included the following 11 utilities: ALLETTE Inc., Black Hills Corporation, CenterPoint Energy, CMS Energy Corporation, Dominion Energy Inc., DTE Energy Corporation, MGE Energy, NorthWestern Corporation, Sempra Energy, Unitel Corp, and WEC Energy Group. Please explain why Concentric did not include these utilities in its U.S. Electric proxy group for these proceedings.

f) Figure 26 (page 64) of Concentric's Alberta report depicts Concentric's MRP estimates, as copied below:

Figure 26: Market Risk Premia – Canada and U.S.

	Canadian	U.S.
Historical	5.74%	7.46%
Forward-Looking	9.22%	7.93%
Average	7.59%	

In contrast, Figure 17 (page 69) of Concentric's current evidence reports a Canadian forward-looking MRP of 12.09% (well more than 30% higher than the 9.22% estimate reported above), a U.S. forward-looking MRP of 11.30% (3.37 percentage points higher than the 7.93% reported above), and an average MRP estimate of 9.06% (1.47 percentage points higher than the average of 7.59% reported above). Would Concentric agree that these are material variations in estimates obtained only 8 months apart and using similar processes and data? If not, please explain why not. If so, what are the implications of such variations to application of Concentric's MRP methodology?

g) Considering the references above, please explain why Concentric now believes that Ontario utilities require higher equity thickness and a higher allowed ROE than those it recommended for Alberta utilities.

h) Does Concentric believe that Ontario utilities are riskier than their Alberta counterparts? If so, please provide evidence to support this assertion.

Response:

a) Please see the response to AMPCO/IGUA-16(a).

b) Please see the response to AMPCO/IGUA-4(d).

c) Enbridge Inc. was included in Concentric's Canadian proxy group, North American Gas proxy group, and North American combined proxy group in this proceeding because the company meets the criteria for inclusion in the Canadian proxy group as described on page 45 of Concentric's report, Exhibit M2. Specifically, Enbridge Inc. has an investment grade credit rating of BBB-. The AUC's North American proxy group did not include Enbridge Inc. due to the fact that the company is primarily an oil and gas pipeline company with a relatively small percentage of revenues, operating income and assets dedicated to gas distribution service. Concentric adopted the AUC's North American proxy group for use in our evidence and analysis in the GCOC proceeding in Alberta in 2023. However, Enbridge Inc. has expanded its presence in gas distribution since the AUC proceeding through the acquisition of gas distribution companies from Dominion Energy Inc. in North Carolina, Ohio, Utah, Idaho and Wyoming. This acquisition added approximately three million gas distribution customers to Enbridge Inc.

d) The companies in the U.S. Electric proxy group in this proceeding were selected by Concentric based on the screening criteria outlined on page 45 of Concentric's report, Exhibit M2. The four electric utilities identified in the question passed each of the stated criteria for inclusion in the proxy group. The AUC used slightly different screening criteria to develop a North American proxy group of companies that it determined were comparable in risk to Alberta's electric and gas utilities in Proceeding 27084. Concentric adopted the AUC's North American proxy group for use in our evidence and analysis in the GCOC proceeding in Alberta in 2023.

e) The eleven U.S. companies identified in the question did not meet one or more of the screening criteria that Concentric used in this proceeding, as outlined on page 45 of Concentric's report, Exhibit M2. For that reason, these companies were not included in the U.S. electric proxy group in the Ontario proceeding. Concentric conducts monthly screens of utilities to determine relevant proxy groups. The proxy group screens set parameters for utility metrics, including but not limited to credit ratings, earnings growth, source of operating income, and transaction history. It is not uncommon for the proxy groups to change based on company specific factors.

f) Yes, Concentric agrees that there are material variations in the forward-looking MRP derived in the Alberta proceeding as compared to the same analysis in the Ontario proceeding, although Concentric observes that more than eight months have passed since our ROE analysis was performed in the Alberta GCOC proceeding. However, the level of the forward-looking MRP is not a relevant consideration because Concentric chose to rely on the more conservative average of the historical MRPs for

Canada and the U.S. in our reports in both Ontario and Alberta.

g) The reference cited is only partial, the complete paragraph from page 92 Concentric's report for ENMAX submitted to the AUC on February 1, 2023 states:

> We have considered not only the financial metrics necessary to maintain a credit rating in the "A" range for each utility sector, and for EPC specifically, but also the utilities' relative risk profiles, and comparable equity returns available for North American utilities. On that basis, we find an increase in the deemed equity ratio for Alberta's transmission and distribution utilities to 40.0 percent is necessary to minimally meet the fair return standard. This ratio is on par with credit rating agency guidance, albeit at the low end of guidance for an investment-grade credit rating by Moody's. It is also aligned with the deemed equity ratios of comparable-risk electric utilities in Ontario and elsewhere across Canada. At our recommended return of 9.5 percent, this equity thickness is appropriate when compared to other Canadian utilities but is still well below the average authorized equity ratio of 51.2 percent for investor-owned U.S. electric utilities in 2021 and 2022.

Concentric emphasized in this paragraph that 40.0 percent was the minimum necessary to meet the FRS, at the low end of guidance for an investment-grade credit rating and still well below the average of U.S. peers. At that point in time, Ontario's electric utilities had an authorized 40% equity ratio. We consider this proceeding an opportunity for the OEB to establish equity ratios that fully meet the FRS and "reflect progress towards parity for equity thickness among North American peers." The complete rationale and support for this recommendation is provided in pages 107-141 of Concentric's report, in response to OEB Issues 11, 12 and 13.

h) Concentric's analysis and recommendations are not based on a narrow risk comparison to Alberta; they are based on a comparison to the North American peers as described on pages 107-141 of Concentric's report in response to OEB Issues 11, 12 and 13.

Ontario Energy Association (OEA)

Answer to Interrogatory from
Association of Major Power Consumers in Ontario (AMPCO) / Industrial Gas Users Association (IGUA)

INTERROGATORY

Reference:

On page 46, Concentric provides its Canadian proxy group in Figure 4 as copied below:

Figure 4: Canadian Proxy Group

Company	Ticker
AltaGas Limited	ALA
Canadian Utilities Limited	CU
Emera, Inc.	EMA
Enbridge, Inc.	ENB
Fortis, Inc.	FTS
Hydro One Ltd.	H

2024 Alberta Utilities Commission Proceeding 27084, Determination of the Cost-of Capital Parameters in 2024 and Beyond, November 10, 2022 (GCOC), memo to all parties, Appendix A – Finalized screening criteria," (27084-X0256 2022-11-10 Appendix A - Finalized screening criteria):

> *The following publicly traded Canadian utility holding companies are included in the comparator group, regardless of the screening criteria:*
> - *Algonquin Power & Utilities Corp.*
> - *Canadian Utilities Ltd.*
> - *Emera Inc.*
> - *Fortis Inc.*
> - *Hydro One Ltd.*

2024 Alberta Utilities Commission Proceeding 27084, Determination of the Cost-of Capital Parameters in 2024 and Beyond, Generic cost of capital issues list and other matters" (27084-X0255 2022-11-10 AUC letter - GCOC issues list and other matters), page 4 (bold added for emphasis):

> *15. While consensus was successfully reached on the majority of items discussed at the technical conference, certain matters remained outstanding and required further submissions from all parties, which the Commission received on November 2, 2022. The Commission has*

reviewed these submissions and provides a ruling on each unresolved item below:
(a) Inclusion of TC Energy Corporation and Enbridge Inc. – The Commission has determined that ***the comparator group will not include TC Energy Corporation and Enbridge Inc****. Integration of these companies would be inconsistent with the Commission's prior approach for determining ROE.*[16] ***Furthermore, the associated business risk, form of regulation and comparability of the two companies is not representative of that for regulated transmission and distribution utilities*** *under the Commission's jurisdiction. The majority of parties took a similar position in their November 2, 2022, submissions*.

16 Decision 22570-D01-2018: 2018 Generic Cost of Capital, Proceeding 22570, August 2, 2018, paragraph 273.

<u>Question(s)</u>:

a) Please confirm that the five Canadian utilities included in the AUC's Canadian proxy group listed above were determined to be reasonable comparable Canadian utilities during the 2024 Alberta Generic Cost of Capital Proceedings.

b) Please confirm that during the 2024 Alberta GCOC Proceedings Mr. Coyne of Concentric opposed the inclusion of AltaGas Limited (a BBB- rated utility) as a reasonable Canadian utility comparator.

c) Please confirm that at the time of the Alberta GCOC proceeding, relative to the AUC's approved proxy group as noted in the above references, AltaGas Limited had:

   i) the highest growth estimate of 8.98% versus group average of 5.27% (which includes AltaGas' high growth rate);

   ii) the second highest DCF Constant-Growth Ke estimate used by Concentric for its Canadian proxy group of 13.22% versus group average of 10.56% (which includes AltaGas' high Ke estimate);

   iii) the highest beta estimate used by Concentric for its Canadian proxy group of 1.16 versus group average of 0.84 (which includes AltaGas' high beta estimate); and

   iv) the highest CAPM (Historical MRP) Ke estimate used by Concentric for its Canadian proxy group of 11.39% versus group average of 9.36% (which includes AltaGas' high Ke estimate).

d) Please explain why AltaGas is now included by Concentric in its Canadian Proxy Group for the purposes of its evidence in this proceeding.

e) Please confirm that at the time of the 2024 Alberta GCOC proceeding, relative to the AUC's approved proxy group as noted in the above references, Enbridge Inc. had:

   i) the highest expected dividend yield of 7.77% versus group average of 5.28% (which includes Enbridge's extremely high dividend yield);

   ii) the second highest DCF Constant-Growth Ke estimate used by Concentric for its Canadian proxy group of 12.56% versus group average of 10.56% (which includes Enbridge's high Ke estimate);

   iii) the second highest Beta estimate used by Concentric for its Canadian proxy group of 0.89 versus group average of 0.84 (which includes Enbridge's' high beta estimate); and

   iv) the second highest CAPM (Historical MRP) Ke estimate used by Concentric for its Canadian proxy group of 9.69% versus group average of 9.36% (which includes Enbridge's high Ke estimate).

f) Please confirm that if Concentric excluded AltaGas Limited and Enbridge Inc. from its Canadian proxy group in this proceeding, that:

   i) The average constant-growth DCF Ke estimate would decline 1.17% from 10.56% to 9.39%.

   ii) The average CAPM (historical MRP) Ke estimate would decline 0.58% from 9.36% to 8.78%.

   If not confirmed, please explain.

Response:

a) Confirmed.

b) Concentric adopted the North American proxy group as determined by the Alberta Utilities Commission and provided to the parties in Appendix B to its November 10, 2022 letter describing the final issues list in Proceeding 27084. The AUC's proxy group did not include AltaGas Ltd.

c) Concentric is not able to confirm this information for AltaGas Ltd. because, as stated in the response to part (b) above, AltaGas Ltd. was not included in Concentric's ROE analysis in the referenced Alberta GCOC proceeding.

d) AltaGas Ltd. was included in Concentric's Canadian proxy group, North American

Gas proxy group, and North American combined proxy group in this proceeding because the company meets the criteria for inclusion in the Canadian proxy group as described on page 45 of Concentric's report, Exhibit M2. Specifically, AltaGas Ltd. has an investment grade credit rating of BBB-. The AUC's North American proxy group only included those companies with a credit rating of BBB+ or higher, which led to the exclusion of AltaGas. Concentric adopted the AUC's North American proxy group in our evidence in the GCOC proceeding in Alberta in 2023.

e) See response to subpart (c) above. Because Enbridge Inc. was not included in Concentric's analysis in the referenced Alberta GCOC proceeding, we are unable to confirm this information.

f) Confirmed. Concentric notes that the values cited in (i) do not include the 50-bps flotation cost adjustment, while the values in (ii) do. In addition, we note that the constant-growth DCF results did not inform our final recommendation; the multi-stage DCF results did. In addition, our recommendation was based on the North American Combined proxy group, not the Canadian proxy group.