VIA RESS and EMAIL

November 7, 2024

Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, Ontario M4P 1E4

Dear Nancy Marconi:

Re: Ontario Energy Board
Generic Proceeding on Cost of Capital
Consumers Council of Canada (CCC) Submission
OEB File No. EB-2024-0063

In accordance with the OEB's letter, dated October 15, 2024, please find attached CCC's submission on all issues in the Generic Proceeding on Cost of Capital.

Yours truly,

Lawrie Gluck

Lawrie Gluck
Consultant for the Consumers Council of Canada

cc: All parties in EB-2024-0063

Ontario Energy Board Generic Proceeding

Cost of Capital Review

EB-2024-0063

Consumers Council of Canada Submission

November 7, 2024

TABLE OF CONTENTS

1. Introduction

On March 6, 2024, the Ontario Energy Board (OEB) initiated a generic proceeding on its own motion to consider the cost of capital parameters and deemed capital structure to be used to set rates for electricity transmitters, electricity distributors, natural gas utilities, and rate-regulated electricity generators (Cost of Capital proceeding). On April 22, 2024, the OEB issued the approved issues list for the proceeding. The issues list includes 22 issues and there is overlap between many of the issues.

The OEB received four expert reports in the Cost of Capital proceeding as follows:

- London Economics International LLC (LEI) – OEB staff
- Concentric Energy Advisors (Concentric) – Coalition of Large Distributors (CLD+)
- Nexus Economics (Nexus) – Electricity Distributors Association (EDA)
- Dr. Sean Cleary (Dr. Cleary) – Industrial Gas Users Association (IGUA) and Association of Major Power Consumers in Ontario (AMPCO)

The OEB provided the opportunity for discovery regarding the expert evidence through written interrogatories and a six-day oral hearing.

The Consumers Council of Canada (CCC) notes that the rate implications of this proceeding are substantial across the regulated energy sector in Ontario. A reasonable estimate is that a change to the return on equity (ROE) of 100 basis points, if applied to all rate-regulated utilities in Ontario, has a revenue requirement impact of over $440 million with no change to the existing equity thickness.[1]

CCC submits that the base ROE for Ontario's electricity distributors and transmitters should be set at 7.1% (which excludes transaction costs). The equity thickness for electricity distributors and transmitters should be maintained at 40%. The ROE and capital structure for Enbridge Gas Inc. (Enbridge Gas) and Ontario Power Generation (OPG) should be established separately from electricity distributors and transmitters. This should occur at each of Enbridge Gas's and OPG's next rebasing applications.

A summary of CCC's main proposals is set out below in section 2 of the submission, which is supported by the detailed analysis and argument in the sections that follow.

[1] EB-2024-0063, School Energy Coalition (SEC) Submission, November 7, 2024, Appendices. SEC calculated a 50bp change to result in a $220M impact on revenue requirement.

2. Submission Summary

CCC's main proposals are summarized in the table below.

Issue	Issues List Numbers	Submission Summary

Return on Equity and Capital Structure	1-3, 10-13	• Set the base ROE at 7.1% for electricity distributors and transmitters (with no transaction costs included)
		• Establish a generic deferral account available to all electricity distributors and transmitters to record actual equity-related transaction costs
		• Make no changes to the ROE or capital structure for Enbridge Gas and OPG in the current proceeding
		    ○ Direct Enbridge Gas and OPG to file proposals in their next rebasing applications
		• Maintain the equity thickness of 40% for electricity distributors and transmitters assuming the OEB agrees with the proposal to set the ROE and capital structure separately for Enbridge Gas and OPG
		    ○ If the OEB decides to continue to set a single ROE for all utilities, the equity thickness for electricity distributors and transmitters should be reduced to 36%
		• Continue the formulaic approach for annual adjustments to ROE with some modifications relative to the current formula

Short-Term Debt	4-5	• Use the average of 3-month Canadian Overnight Repo Rate Average (CORRA) futures rates for the next 12-month period plus a spread based on 2023 bank survey (adjusted by adding historical observed difference between 3-month CORRA and 3-month Bankers' Acceptance (BA) rates) to establish the deemed short-term debt rate for 2025 • Use the average of 3-month CORRA futures rates for the next 12-month period plus a spread based on the historical 12-month spread between Bloomberg BVCAUA3M BVLI Index and the 3-month CORRA to establish the deemed short-term debt rate in future years • Continue to apply the deemed short-term debt rate for ratemaking purposes for electricity distributors and transmitters

Long-Term Debt	6-9	• Apply the Long Canada Bond Forecast (LCBF) based on the actual September 30 Government of Canada bond yield plus the actual A-rated utility spread on the same date to establish the deemed long-term debt rate (DLTDR) • Continue to use actual long-term debt costs for rate setting purposes (and apply the DLTDR as a cap) • Continue to record actual debt-related transaction costs as an interest expense and amortize the transaction cost over the term of the debt instrument using the effective interest methodology
Implementation	14-19	• Apply the updated ROE and equity thickness determined in the current proceeding at the next rebasing for each electricity distributor and transmitter • Continue annual updates to the cost of capital parameters through formulaic approach using September data each year • Continue to internally monitor the industry and confirm that the fair return standard is met through the OEB's annual capital update letters • Monitoring should now include a review of credit rating information and actual debt and equity issuances of the Ontario utilities • Hold a generic cost of capital proceeding every 5 years
Prescribed Interest Rates for Deferral and Variance Accounts and Construction Work in Progress	20-21	• Continue to apply the deemed short-term debt rate to deferral and variance account (DVA) balances (as updated in the current proceeding) • Continue to apply a mid-term debt rate to Construction Work in Progress (CWIP)
Cloud Computing Deferral Account	22	• Apply the deemed short-term debt rate to all balances in the Cloud Computing Deferral Account

3. Return on Equity and Capital Structure

CCC submits that the OEB should make changes to the ROE for only Ontario's electricity distributors and transmitters in the Cost of Capital proceeding. There are sufficient differences in the risk profiles of electricity distributors and transmitters relative to Enbridge Gas and OPG that suggest that both the allowed ROE and capital structures for each of those two companies should be addressed individually in future rebasing proceedings.

CCC submits that the base ROE for electricity distributors and transmitters should be set at 7.1%, which aligns with Dr. Cleary's updated Bond Yield Plus Risk Premium (BYPRP) estimate (excluding the transaction cost / financial flexibility adder).[2] The equity thickness for electricity distributors and transmitters should be maintained at 40%. Establishing the base ROE for Ontario's electricity distributors and transmitters at 7.1% would set the ROE for these companies below the long-term expected average Canadian market return (i.e., 7.5%[3]), which properly reflects that these firms are lower risk than the market on average.

In the circumstance that the OEB decides that the ROE it establishes in the current proceeding will apply to all Ontario rate-regulated utilities (and that it will continue to use the capital structure to reflect the risk differential between sectors), the deemed equity thickness applicable to Ontario's electricity distributors and transmitters should be reduced to 36%.

The changes to the ROE and capital structure should be implemented for each electricity distributor and transmitter at the time of their next rebasing proceeding (and not before then).

The OEB should continue to use a formulaic approach for updating the ROE each year in between generic cost of capital review proceedings. CCC prefers Dr. Cleary's formula as set out in Undertaking J5.3.[4] Therefore, the formula (inclusive of CCC's proposed base ROE, the initial Long Canada Bond Forecast (LCBF) and the initial utility bond spread) is as follows:

ROE = 7.10% + 0.75 x (LCBF – 3.13%) + 0.75 x (UtilBondSpread – 1.39%).

[2] Undertaking J5.3, p. 3.
[3] Exhibit M4, p. 83. Dr. Cleary calculates the expected Canadian stock market return using both historical data and forecast information from investment professionals.
[4] Undertaking J5.3, pp. 4-5.

However, if the OEB is concerned with the 0.75 adjustment factor applied to the LCBF and the utility bond spread as set out in Dr. Cleary's formula, maintaining the existing adjustment factor of 0.5 is a reasonable alternative.

With respect to OPG, there should be no change to the ROE or equity thickness ordered in the Cost of Capital proceeding. OPG is in the middle of its current Custom Incentive Ratemaking (Custom IR) term (2022-2026) and no change to its ROE or equity thickness should be made now. Instead, the OEB should direct OPG to file evidence supporting a proposal for both a ROE and capital structure for OEB review at the time of its next rebasing proceeding (for the next rate term starting in 2027).

Similarly, Enbridge Gas is at the outset of its rate-setting term (2024-2028). The OEB, less than one year ago, reviewed Enbridge Gas's equity thickness and approved an increase from 36% to 38% (and applied the OEB-approved 2024 ROE of 9.21%). There is no basis for a revision to the ROE nor the equity thickness during its rate term. Instead, the OEB should direct Enbridge Gas to file evidence supporting a proposal for both a ROE and capital structure for OEB review at the time of its next rebasing proceeding (for the next rate term starting in 2029).

CCC acknowledges that a reduction to the ROE from the current 9.21% to 7.1% is a significant change to happen all at once. However, it is CCC's view that a base ROE of 7.1% meets the fair return standard for Ontario's regulated electricity distributors and transmitters. If the OEB is concerned about the pace of the change, an alternative is to reduce the ROE to the half-way point between the 2009 implied equity risk premium (550 basis points) and the implied equity risk premium of 397 basis points resulting from CCC's proposed 7.1% base ROE. This would set the base ROE at 7.87% in the current proceeding and the OEB should acknowledge that this is a step-change relative to the current ROE and further reductions may be needed in future cost of capital proceedings. The OEB can monitor whether this reduction to the allowed ROE has any negative implications for Ontario's electricity distributors and transmitters with the plan to continue to reduce the ROE further at the next generic cost of capital review assuming the macroeconomic environment is supportive of further reductions.

3.1. The Fair Return Standard and the Return on Equity established in the OEB's 2009 Cost of Capital Report

The OEB, in its 2009 Cost of Capital Report, stated that the fair return standard frames the discretion of a regulator, by setting out three requirements that must be satisfied by the cost of capital determinations of the tribunal. Meeting the standard is not optional; it is a legal requirement.[5]

The fair return standard establishes that a fair or reasonable return on capital should:

- be comparable to the return available from the application of invested capital to other enterprises of like risk (the comparable investment standard)
- enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard)
- permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).[6]

The OEB further stated that all three standards or requirements (comparable investment, financial integrity and capital attraction) must be met and none ranks in priority to the others. The OEB stated that focusing on meeting the financial integrity and capital attraction tests without giving adequate consideration to the comparability test is not sufficient to meet the fair return standard.[7]

With respect to the role of the comparable investment standard, the OEB stated the following:

> Continued investment in network utilities does not, in itself, demonstrate that the FRS has been met by a regulator's cost of capital determination, and in particular, whether the determination of the equity cost of capital meets the requirements of the FRS. This is a particular challenge – how does the regulator determine when investment capital is not allocated to a rate regulated enterprise? These decisions are typically made

[5] Ontario Energy Board, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, p. 18.
[6] National Energy Board. RH-2-2004, Phase II Reasons for Decision, TransCanada PipeLines Limited Cost of Capital, April 2005, p. 17.
[7] Ontario Energy Board, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, p. 19.

> within the utility/corporate capital budgeting process and rarely, if ever, broadly communicated to stakeholders. The Board notes that acquisition and divestiture activities of regulated utilities are not definitive in this regard, one way or the other, and notes that there are many reasons why investors are willing to acquire or desirous of selling utility assets, notwithstanding their view of whether an allowed ROE meets the FRS.
>
> The primary tool available to the regulator to rectify this lack of transparency is the comparable investment standard. By establishing a cost of capital, and an ROE in particular, that is comparable to the return available from the application of invested capital to other enterprises of like risk, the regulator removes a significant barrier that impedes the flow of capital into or out of, a rate regulated entity. The net result is that the regulator is able, as accurately as possible, to determine the opportunity cost of capital for monies invested in utility works, with the ultimate objective being to facilitate efficient investment in the sector.[8]

In the 2009 Cost of Capital Report, to estimate an ROE that meets the comparable investment standard (and the overall fair return standard), the OEB relied on multiple tests and averaged the results of the tests proposed by each expert to determine an implied equity risk premium. The equity risk premium of 550 basis points (or 5.5%) resulting from the average of those tests was added to the forecast long term Government of Canada bond yield of 4.25% (or risk-free rate) to establish the base ROE of 9.75%.[9]

With respect to the comparability of Ontario utilities to other enterprises of like risk in terms of satisfying the comparable investment standard, the OEB set out the following principles/findings:

- “Like” risk does not mean the “same” risk
- Canadian and U.S. utilities can be comparators and only an analytical framework in which to apply judgement and a system of weighting are needed.[10]

---

[8] Ontario Energy Board, Report of the Board on the Cost of Capital for Ontario’s Regulated Utilities, December 11, 2009, p. 21.
[9] Ontario Energy Board, Report of the Board on the Cost of Capital for Ontario’s Regulated Utilities, December 11, 2009, pp. 31-32. The equity risk premium of 550 basis points was based on an average of the estimates from 5 experts (and included a total of 18 estimates). The estimates were based on a wide-range of tests including the discounted cash flow approach, capital asset pricing model, equity risk premium approach and a number of other estimation approaches.
[10] Ontario Energy Board, Report of the Board on the Cost of Capital for Ontario’s Regulated Utilities, December 11, 2009, pp. 21-22.

CCC submits that the result of the OEB's approach in the 2009 Cost of Capital Report was the establishment of a base ROE that was in excess of the level required to meet the fair return standard.

A key concept in the OEB's 2009 Cost of Capital Report is the setting of an ROE that results in "efficient investment"[11] in the sector. CCC submits that the OEB's statement regarding "efficient investment" is intended to frame the analysis in a manner that ensures that ROE is set at level that is neither too high nor too low to ensure that investment in the sector is optimized.

CCC submits that it is likely that a regulator will end up setting the ROE higher than what is necessary to meet the fair return standard as it will ensure that any possible financial integrity problems for utilities are avoided. Financial integrity problems that result from setting an ROE too low will be observable through the potential deterioration of reliability and a flight of capital, which is obviously problematic for the sector and its regulator. However, an ROE that is set above the minimum needed to meet the fair return standard will result only in the theoretical payment of economic rent to utilities by ratepayers, which is not directly observable. While the payment of economic rent is not directly observable, it is clearly not reasonable and also does not meet the fair return standard.[12]

So, how does a regulator determine whether an ROE is set too high? There are a number of ways to analyze this problem. CCC submits that an initial step is to evaluate whether the ROE is meeting the financial integrity and capital attraction standards.[13] Second, reviewing price-to-book ratios (P/B ratios) provides an indicator of whether ROEs are set too high. Third, it is important to evaluate whether the ROE is resulting in excessive actual, or proposed, investment in the sector. Finally, a review of recent academic literature regarding rate of returns for regulated utilities is useful.

The OEB has evidence that the OEB-approved ROEs (as updated by the annual formulaic adjustment) since 2009 have been successful at maintaining the financial integrity of Ontario utilities and the utilities have had no difficulty attracting capital. This is confirmed by LEI and Concentric. LEI stated that it "is not aware of OEB-regulated entities facing

[11] Ontario Energy Board, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, p. 15, 21, 31.
[12] Exhibit N-M1-11-OEA-12. LEI stated that an unreasonably high ROE and/or equity thickness also fails to meet the fair return standard.
[13] Evaluating whether an ROE meets the financial integrity and capital attraction standards would not indicate that an ROE is too high, but it does confirm that it is not too low.

notable issues in attracting equity and debt capital since 2009."[14] LEI also stated that "Ontario utilities have been able to raise capital at reasonable terms since 2006, which is one of the best indicators that FRS is being met."[15] Similarly, Concentric stated that it "is not aware of Ontario utilities failing to attract capital or being in danger of losing their financial integrity since the 2009 Decision…"[16] Therefore, the OEB-approved ROE, which was as low as 8.34% in 2021[17], has not resulted in any concern that the financial viability and capital attractions standards have been met historically.

The fact that the historical OEB-approved ROEs, as determined through the 2009 Cost of Capital Report and subsequently updated based on a formulaic approach, have met the financial integrity and capital attraction standards implies that the approved ROEs were, at least, sufficient to meet those two aspects of the fair return standard. What it does not imply is whether the ROEs were higher than the minimum necessary to meet the fair return standard overall.

CCC submits that reviewing P/B ratios is a reasonable method to determine whether existing ROEs are too high. As noted by Dr. Cleary, current ROEs in Canada are inflated based on average P/B ratios for the 2017-2023 period for Canadian publicly traded utilities of 1.65. Dr. Cleary stated that higher ratios indicate greater future growth opportunities, and firms that have P/B ratios greater than one are earning (and expected to earn) rates of return that are at least "fair," if not above fair. Dr. Cleary noted that if P/B ratios exceed 1.0, it indicates that the firm is earning excess economic rent. Dr. Cleary further stated the only publicly listed regulated operating Canadian utility (i.e., Hydro One) had a P/B ratio of 2.04 as of the end of 2023.[18] CCC submits that the P/B ratios of Canadian utilities and particularly for Hydro One, which is an Ontario rate-regulated utility, provide a clear sign that ROEs for regulated utilities in Canada, and more importantly in Ontario, are higher than is necessary to meet the fair return standard.

Another approach to evaluating whether the existing ROE is higher than is necessary to meet the fair return standard is to look at the investments of utilities over the years. The OEB has extensive evidence that utilities, in their rebasing applications, seek to make capital investments as set out in their respective distribution system plans and utility system plans that are beyond what the OEB actually finds to be necessary (or, in other

[14] Exhibit M1, p. 127.
[15] Exhibit N-M1-11-OEA-12.
[16] Exhibit N-M2-10-CME-1.
[17] Cost of Capital Parameter Updates | Ontario Energy Board.
[18] Exhibit M4, p. 36.

words efficient) for the purposes of setting just and reasonable rates. This can be observed through numerous OEB decisions and OEB-approved settlement proposals that reduce the recoverable capital expenditures (and related in-service additions) relative to the proposed amounts.[19] The utilities' proposals to invest excessive capital (or in other words, capital in excess of what is efficient in the public interest) implies that the current ROE is already too high and resulting in a desire by utilities to make inefficient investments in the sector.

In addition, the shareholders of Ontario's electricity distributors have more actual equity in their businesses than the deemed equity thickness.[20] CCC submits that this implies that these shareholders are: (a) satisfied with earning a lower return on a portion of their actual equity investment[21]; and (b) are prepared to make additional equity investments in their companies.

Finally, a recent working paper, from the Energy Institute at Haas, evaluates whether, and to what extent, U.S. utilities are being allowed to earn excess ROEs by their regulators. The authors conclude that, over the past 30 years, based on various estimation approaches, there is a consistent trend of excess rates of return. The authors find that the current approved average ROE is higher than various benchmarks and historical relations would suggest. Depending on the chosen benchmark, the premium relative to the cost of equity that utilities receive ranges from 0.5% to over 4%. The authors further find that utilities adjust their capital investments in response to the premium on the cost of equity they are likely to earn on those assets.[22] CCC submits that this academic paper, while focused on US rate-regulated utilities, is supportive of its views on the excessive ROE that is currently offered to Ontario's utilities. Particularly, it is clear that there is a connection between ROEs that are set at a premium to the minimum required to meet the fair return standard and the proposals by Ontario utilities for approval of capital investments that are beyond what the OEB has considered to be efficient investment.

[19] For example, Toronto Hydro 2020-2024 Rates, EB-2018-0165, Decision and Order, December 19, 2019, p. 74; Hydro One 2023-2027 Rates, EB-2021-0110, Decision and Order, November 29, 2022, p. 4; and Niagara-on-the-Lake Hydro 2024 Rates, EB-2023-0041, Decision and Order, September 21, 2023, p. 4. This list is not intended to be exhaustive.
[20] Exhibit M1, p. 97.
[21] Exhibit N-M1-9-CCC-4. LEI stated that shareholders of smaller utilities tend to be municipalities who are more comfortable self-funding the debt portion of the deemed capital structure either because the debt return is acceptable or to increase flexibility regarding coverage ratios and other bank covenants.
[22] Karl Dunkle Werner and Stephen Jarvis, Rate of Return Regulation Revisited, Energy Institute at Haas, April 2024, pp. 3, 37-38.

The above analysis leads us to the conclusion that the existing ROE is higher than what is necessary to meet the fair return standard and is resulting in economic rent being paid by ratepayers to utilities. The next question is, what caused the ROE to be set too high?

CCC notes that the OEB's approach to setting the base ROE in 2009 was based on an average of each expert's estimates from the various tests that they applied. In total, the equity risk premium of 550 basis points was based on an average of the estimates from 5 experts (including a total of 18 estimates). The five experts were Dr. Booth, Concentric, Power Advisory LLC, Foster Associates and Dr. J.H Vander Weide. Dr. Booth represented consumer groups, while the other four experts represented utilities.[23]

Taking a closer look at the methodologies applied, there was a reliance in the various estimates on U.S. market data and comparisons to U.S. holding companies. In addition, a number of the estimates were based on U.S. authorized returns.

More specifically, with respect to Concentric's estimates, Concentric relied on:

- U.S. holding companies in its natural gas peer group for its discounted cash flow (DCF) and capital asset pricing model (CAPM) estimates[24]
- U.S. holding companies in its electricity peer group for its DCF and CAPM estimates[25]
- Adjusted betas in its CAPM estimate[26]
- Average of US and Canadian market data in its market risk premium calculation for its CAPM estimate[27]

With respect to Dr. J. H. Vander Weide's estimates, he relied on:

- Recent allowed ROEs in the US for 4 estimates of the equity risk premium[28]
- U.S. holding companies in his DCF analysis[29]

[23] Ontario Energy Board, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, pp. 10-11, 38.
[24] EB-2009-0084, Concentric Report, September 8, 2009, Appendix C, p. C-2.
[25] EB-2009-0084, Concentric Report, September 8, 2009, Appendix C, p. C-3.
[26] EB-2009-0084, Concentric Report, September 8, 2009, Appendix F, pp. F-8-9.
[27] EB-2009-0084, Concentric Report, September 8, 2009, Appendix F, pp. F-10-11.
[28] Ontario Energy Board, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, pp. 38-39.
[29] EB-2009-0084, J.H. Vander Weide Responses to Questions Raised as Issues for Discussion at Stakeholder Conference, September 8, 2009, Appendix A, pp. 18-19.

CCC submits that the reliance on U.S. market data and U.S. proxy groups in the estimates of many of the experts was the key reason that the OEB's 2009 base ROE was set above the level necessary to meet the fair return standard (as all of the estimates were averaged by the OEB in setting the base ROE). In the current proceeding, the experts, with the notable exception of Dr. Cleary, are recommending that the OEB do the same thing again – set the ROE higher than is necessary to meet the fair return standard. These experts are recommending that U.S. data play a predominant role in the establishment of the base ROE in the current proceeding again. CCC submits that this is not appropriate and the specific concerns that we have with the experts' approaches are discussed, in detail, in section 3.3 of the submission.

Based on CCC's premise that the ROE established by the OEB in 2009 is already too high, the next question that needs to be addressed is whether the risk of Ontario utilities has increased significantly since that time. A significant increase in the risk of the Ontario utilities would imply that it is not appropriate to reduce the base ROE in the current Cost of Capital proceeding. In the next section of the report (section 3.2), CCC establishes that the risk of Ontario's electricity distributors and transmitters has not increased since 2009 and, instead, has decreased since that time. CCC also proposes that it is appropriate to address the ROE and equity thickness for only the Ontario electricity distribution and transmission sectors in the current proceeding (and address the cost of capital for Enbridge Gas and OPG in their respective rebasing applications due to differences in risk).

3.2. The Risk Profile of Ontario Utilities

<u>Ontario's Energy Sectors have Different Risks</u>

CCC submits that the risks faced by Ontario's electricity distributors and transmitters are sufficiently different from Enbridge Gas and OPG to suggest that setting the cost of capital separately as between the electricity distribution/transmission sectors, Enbridge Gas and OPG is appropriate.

CCC does not believe it is appropriate to continue to set a single average ROE for all of Ontario's rate-regulated utilities and use the equity thickness as the lever to reflect risk differences between sectors as the OEB has done historically. CCC submits that the ROE and the equity thickness are directly related and should be established by the OEB at the same time (as both must be considered in the determination of whether the fair return standard is met).[30] As will be discussed below, Enbridge Gas and OPG face different risks than Ontario's electricity distributors and transmitters. In addition, as a practical matter, Enbridge Gas's cost of capital was reviewed last year for the setting of 2024 rates and OPG is in the middle of its Custom IR term. Therefore, there will be ample opportunity to review cost of capital matters at each utilities next rebasing.

Risk Differences between Ontario Electricity Distribution / Transmission Sector and Enbridge Gas

It is important to recognize that the OEB, less than a year ago, established 2024 rates (and relatedly, the cost of capital) for Enbridge Gas in a rebasing proceeding that had a very large focus on the potential impact of the energy transition. In Enbridge Gas's 2024 rates proceeding, the OEB, with respect to the cost of capital, stated the following:

> Considering both a decrease in business risk due to amalgamation, and an increase in business risk due to the energy transition, which is partially mitigated by this Decision and Order, the OEB concludes that there is a net increase in business risk that justifies a modest increase in the deemed equity thickness. The OEB is persuaded by the analysis of LEI and its recommended 38% equity thickness. Enbridge Gas has not met the onus to establish that its ultimate requested increase to 42% is reasonable. In the absence of the risk assessment evidence that Enbridge Gas is directed to develop for its next rebasing application, the OEB denies Enbridge Gas's request. The OEB approves an increase to the deemed equity thickness to 38% at this time. The approved increase in equity thickness will be applied to 2024 rates and will not be phased in.[31]

The OEB-approved 2024 ROE, as established through the formulaic approach, was applied to Enbridge Gas's deemed equity portion of rate base.[32]

In the context of the current proceeding, CCC notes that an important aspect of the OEB's findings in Enbridge Gas's 2024 rates proceeding is that energy transition increased Enbridge Gas's business risk. CCC submits that the same is not true for Ontario's electricity distribution and transmission companies. As will be discussed in more detail later in this section of the submission, energy transition is an opportunity for the electricity sector and cannot be seen as a meaningful increase to business risk (particularly, in the context of the regulatory mechanisms available to these companies). The different manner in which energy transition-related risk impacts Ontario's electricity distributors and transmitters and Enbridge Gas is a key differentiator in the risk faced by these sectors.

---

[30] To satisfy the fair return standard, the OEB needs to determine whether the ROE as applied to the deemed equity portion of rate base is reasonable (not just one of those two factors).
[31] EB-2022-0200, Decision and Order, December 21, 2023, p. 68.
[32] EB-2022-0200, Decision and Order, December 21, 2023, p. 61.

Furthermore, CCC submits that any changes to the ROE and equity thickness that may be ordered in the current proceeding should be implemented at each company's next rebasing.[33] Therefore, as a practical matter, there is no need to establish a new ROE and equity thickness for Enbridge Gas now. Enbridge Gas is not scheduled for another rebasing until 2029. Resetting Enbridge Gas's cost of capital in the middle of its current ratemaking term is even more problematic than the rest of the industry generally as the OEB made clear findings directing Enbridge Gas to carry out a risk assessment and to develop an approach to reducing stranded asset risk to be provided at its next rebasing. The OEB specifically linked this risk assessment to its equity thickness findings.[34]

Appropriate Treatment of EPCOR Natural Gas Limited Partnership

CCC submits that EPCOR Natural Gas Limited Partnership (ENGLP) should be applied the same cost of capital treatment as Enbridge Gas. In the context of CCC's proposal above that Enbridge Gas's cost of capital remain unchanged until its next rebasing, this implies that the capital structure and ROE as currently established for ENGLP should also remain in place.

As a practical matter this will not cause any problems with respect to the establishment of rates for ENGLP. With respect to ENGLP's Aylmer service area, it has filed an application for 2025 rates (and an IRM framework for the years 2026-2029) using its existing capital structure.[35] Therefore, the existing capital structure and 2025 ROE (based on the OEB's existing formulaic approach) can remain in place until its next rebasing for 2030 rates and at that time the same ROE and capital structure that is applied to Enbridge Gas in its 2029 rebasing can be applied to ENGLP Aylmer for 2030 rates.

Similarly, ENGLP is not expected to file a rebasing application for its South Bruce service area until 2028 for 2029 rates.[36] Therefore, the capital structure and ROE that is already in place for South Bruce can remain in place until its next rebasing for 2029 and at that time the same ROE and capital structure that is applied to Enbridge Gas in its 2029 rebasing can be applied to ENGLP South Bruce for 2029 rates.

[33] This is discussed in more detail in section 6.1 of the submission.
[34] EB-2022-0200, Decision and Order, December 21, 2023, p. 68.
[35] EB-2024-0130.
[36] EB-2018-0264.

Risk Differences between Ontario Electricity Distribution / Transmission Sector and OPG

CCC submits that OPG has a unique risk profile, as a generation-only regulated utility, that sets it apart from other Ontario utilities. Therefore, the OEB should establish the cost of capital and capital structure for OPG in its next rebasing proceeding.

CCC submits that other regulators have acknowledged the general difference between electricity utilities that own/operate generation (vertically integrated companies) relative to those that are wires only companies. This is reflected in lower average authorized ROEs for electricity distribution/transmission companies relative to vertically integrated companies.[37] Similarly, Concentric acknowledged the difference in risk between companies that own and operate electricity generation as part of their operations relative to businesses that do not in its report before the OEB in the 2009 Cost of Capital proceeding. Specifically, Concentric reduced the ROE resulting from its electricity proxy group to reflect that its proxy group largely included companies that were vertically integrated.[38] This reflects Concentric's view, at that time, that companies with generation assets have higher risk than wires-only companies.

CCC submits that while OPG, as a generation company, generally has higher risk relative to distributors and transmitters, it is also applied a special regulatory treatment by the OEB due to certain legislative considerations. These legislative considerations operate to, directionally, offset this higher risk. CCC notes that OPG has access to some of the same favourable regulatory mechanisms that are discussed later in the submission with respect to Ontario's electricity distributors and transmitters (e.g., Custom IR) but also incrementally benefits from the provisions in Ontario Regulation 53/05 (O. Reg. 53/05). For example, O. Reg. 53/05, provides for numerous deferral and variance accounts that ensure that OPG can recover its prudently incurred costs and firm financial commitments related to new nuclear development, the Pickering B extension project, capacity increases and refurbishments (including the Darlington Refurbishment project), and nuclear decommissioning liabilities.[39] In addition, the Government of Ontario, which is the shareholder of OPG, has signalled increased support for OPG and nuclear power more broadly.[40]

[37] Exhibit J5.2, SEC US Utility ROE Analysis.
[38] EB-2009-0084, Concentric Report, September 8, 2009, Appendix C, p. C-4.
[39] O. Reg. 53/05, Sections 5.4, 5.7, 6(2)4, 6(2)8.
[40] See for example, https://www.ontario.ca/page/ontarios-affordable-energy-future-pressing-case-more-power.

This further supports CCC's view that OPG has a unique risk profile relative to other Ontario utilities and a comprehensive review of its business risks (as mitigated by its special regulatory treatment) and financial risks is needed prior to establishing the ROE and equity thickness for OPG.

Finally, CCC acknowledges Concentric's statement that it has not recommended an ROE applicable to OPG and that OPG could bring forward a proposal in its next payment amounts application regarding the appropriate ROE and equity thickness for the OEB's review. Further, Concentric noted that OPG's current payment amounts are subject to a settlement agreement and its payment amounts should not be adjusted in the interim.[41] CCC notes that the recommendation to wait until OPG's next rebasing to consider its cost of capital and equity thickness is aligned with CCC's proposal that any changes to the cost of capital, as determined in the current proceeding, be implemented at the next rebasing for all utilities (as is discussed, in detail, in section 6.1 of the submission).

For these reasons, CCC submits the OEB should focus its determinations on the ROE and equity thickness for only electricity distributors and transmitters in the current proceeding.

CCC's submissions that follow with respect to the appropriate ROE and equity thickness are focused on Ontario's electricity distribution and transmission sectors.

<u>Ontario Electricity Distributor and Transmitter Risk</u>

We considered the business risks and financial risks for Ontario's electricity distributors and transmitters together as the risks faced by those two sectors are similar. As LEI stated, "the risk profile of electricity transmitters is similar, if not lower than that of electricity distributors."[42]

For the reasons that follow, CCC is of the view that the business risks faced by Ontario distributors and transmitters are lower than they were in 2009, when the OEB last established the base ROE, largely due to favourable regulatory policy changes. In addition, the assessment of financial risks highlights that Ontario distributors and transmitters continue to have no issues attracting capital and have very strong credit ratings.

[41] Exhibit N-M2-19-SEC-57.
[42] Exhibit M1, p. 143.

<u>*Business Risks*</u>

CCC submits that the two main changes to business risks since 2009 are the changes to the OEB's regulatory policy and the introduction of energy transition-related risk.

Regulatory Policy Changes

Since 2009, the OEB has significantly advanced its policies applicable to Ontario's distributors and transmitters in a manner that has de-risked these utilities. It is important to acknowledge that, from the perspective of investors, the perceived stability of future cash flows is a key consideration. Given that a regulated utility's ability to recover its capital and operating costs is directly linked to the available regulatory mechanisms, the regulatory framework that a utility operates within plays an extremely important role in either increasing or decreasing a utility's business and financial risks.[43] Therefore, the OEB should weigh regulatory policy changes very highly in its analysis of whether the risk faced by Ontario distributors and transmitters has changed.

LEI, in its report, provided a review of the major OEB regulatory policy changes[44] and the School Energy Coalition (SEC)[45] added to that list in interrogatories that it asked each expert. CCC provides its views on the risk implications of the major policy changes introduced by the OEB since the base ROE was previously established below.

CCC notes that the OEB has established a large number of generic deferral and variance accounts (DVAs) since 2009. There have also been many utility-specific accounts that have been established since that time. With respect to the generic deferral accounts[46], the OEB has established the[47]:

- Customer Choice Initiative deferral account
- Broadband deferral account
- Getting Ontario Connected Act variance account
- Low-income Energy Assistance Program Emergency Financial Assistance deferral account

[43] Exhibit M1, p. 74.
[44] Exhibit M1, pp. 63-76.
[45] Exhibit N-M1-3-SEC-11.
[46] CCC notes that some of the generic accounts listed below have since been closed since the time they were established but they show the OEB's proactiveness in addressing the recovery of costs outside of the utilities' control.
[47] This list is not intended to be exhaustive.

- Cloud Computing deferral account[48]
- OEB Cost Assessment variance account[49]
- COVID-19 deferral account[50]
- Green Button Initiative deferral account[51]

With respect to utility-specific DVAs, there are too many to list in this submission. However, as a representative example, the OEB has approved the Externally Driven Capital variance account for Toronto Hydro Electric System Limited (Toronto Hydro) and Hydro One Networks Inc. (Hydro One). This account allows Toronto Hydro and Hydro One to recover the revenue requirement related to capital cost variances associated with externally driven work requests, which are potentially outside these utilities' control, during the Custom IR term.[52]

The above noted generic and utility-specific DVAs directly reduce the risk of Ontario's electricity distribution and transmission companies by allowing the recovery of costs during rate-setting terms from ratepayers that otherwise would be borne by the shareholder in the absence of DVA treatment. This reduction of risk was acknowledged by LEI.[53] Just as important as the direct reduction to risk resulting from the establishment of generic DVAs, these accounts highlight the OEB's proactiveness in ensuring that Ontario's electricity distribution and transmission companies have every opportunity to earn their entire OEB-approved ROE as they are protected from many categories of cost variances that may occur during their IR terms.

With respect to the Renewed Regulatory Framework (RRF), which was introduced in 2012[54], the introduction of the advanced capital module (ACM) in 2014[55], and changes to the OEB's

---

[48] Exhibit M1, pp. 64-65.
[49] OEB Letter to Regulated Entities subject to the OEB's Cost Assessment Model, February 9, 2016.
[50] EB-2020-0133, Report of the Ontario Energy Board, Regulatory Treatment of Impacts Arising from the COVID-19 Emergency, June 17, 2021.
[51] EB-2021-0183, Accounting Order for the Establishment of a Deferral Account to Record Impacts Arising from Implementing the Green Button Initiative, November 1, 2021.
[52] EB-2018-0165, Toronto Hydro 2020-2024 Rates, Decision and Order, December 19, 2019, p. 198; and EB-2021-0110, Hydro One Joint Rate Application, Settlement Proposal, October 24, 2022, pp. 90, 92.
[53] Exhibit M1, p. 75.
[54] Report of the Ontario Energy Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-based Approach, October 18, 2022.
[55] EB-2014-0219, Report of the Ontario Energy Board, New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014.

incremental capital module (ICM) and ACM in 2016[56] and 2022[57], the OEB increased the flexibility, scope and allowance for Ontario utilities to recover incremental capital costs during ratemaking terms (after the test year). The overall impact was very favourable to Ontario's utilities.

The introduction of a Custom IR option allowed electricity distributors and transmitters to propose ratemaking mechanisms that allow for the recovery of incremental capital costs in the post-test year period on a forecast basis. To date, the Custom IR frameworks that have been approved by the OEB effectively allow for recovery of increasing capital budgets in each year of the Custom IR term.[58] CCC submits that the Custom IR approach, as has been applied in Ontario to date, is comparable to a five-year cost of service for capital-related costs (with a stretch factor applied). This clearly reduces both the risk of capital cost recovery and reduces cost recovery lag (as the utility no longer must wait until its next rebasing period to include capital costs in rate base for recovery to begin).

The introduction of the ACM in 2014 allows utilities to request future capital recovery in its rebasing for capital projects that are expected to be placed in-service in the outer years of the incentive ratemaking term. As noted by the OEB, this provides for the recovery of costs for discrete capital projects when they are needed through the Price Cap IR cycle.[59]

With respect to changes to the ICM, in 2016, the OEB reduced the ICM/ACM deadband from 20% to 10%.[60] And in 2022, the OEB expanded the availability of the ICM to utilities that are in the latter years (i.e., years six to ten) of a deferred rebasing period.[61] The result of these changes is an increase to the allowable recovery of capital costs during incentive ratemaking terms.

Overall, CCC submits that the combined impact of the introduction of these new policies and modifications to the existing policy around ICM is to allow for the recovery of prudently

[56] EB-2014-0219, Supplemental Report on New Policy Options of the Funding of Capital Investments, January 22, 2016.
[57] OEB Letter, Incremental Capital Modules during Extended Deferred Rebasing Periods, February 10, 2022.
[58] For example, EB-2018-0165, Toronto Hydro 2020-2024 Rates, Decision and Order, December 19, 2019, pp. 15-16, 23; and EB-2021-0110, Hydro One Joint Rate Application, Settlement Proposal, October 24, 2022, pp. 25-26.
[59] EB-2014-0219, Report of the Ontario Energy Board, New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014, p. 11.
[60] EB-2014-0219, Supplemental Report on New Policy Options of the Funding of Capital Investments, January 22, 2016, p. 18.
[61] OEB Letter, Incremental Capital Modules during Extended Deferred Rebasing Periods, February 10, 2022, p. 1.

incurred capital costs in between rebasing applications. The utilities have benefited significantly from these policies. There have been countless ICM requests each year and many of the larger distributors have availed themselves of the Custom IR ratemaking option. The operation of these new policies has de-risked Ontario's distributors and transmitters significantly.

In addition, CCC notes that, in 2015, the OEB established a policy designed to move all electricity distributor rates to fixed charges for residential customers.[62] This resulted in greater certainty of cost recovery from the residential class of customers, which de-risked utilities (relative to a fixed / variable rate design that was previously in place) and more closely align the cost recovery with the largely fixed nature of distribution costs.

The OEB also issued a policy with respect to the integration of distributed energy resources (DERs) in system planning and the use of DERs by electricity distributors as non-wires alternatives.[63] CCC agrees with LEI that, while the penetration of DERs introduces some uncertainty into future investment plans, the OEB's policy sufficiently mitigates this uncertainty.[64] The OEB provided clear direction with respect to its expectations for DER integration, provided the availability of a deferral account to record OM&A costs related to DER integration to be used in advance of rebasing, and is even allowing for incentives to be paid on third-party owned DERs that are integrated as non-wire solutions.[65] The OEB further clarified its policy regarding non-wire solutions for electricity distributors in 2024.[66] CCC submits that the OEB has been proactive in addressing the potential risks arising from DER integration and has ensured that electricity distributors are well shielded from these risks.

Finally, since 2009, the OEB has made a number of changes to its policies that operate to reduce lag in cost recovery (or, regulatory lag). In this regard, the OEB introduced the following policy changes:

- In 2015, the OEB made changes to the Distribution System Code (DSC) that required residential customers and small volume general service customers to be billed on a monthly basis (relative to the previous approach where many customers

[62] EB-2012-0410, Ontario Energy Board Policy, A New Distribution Rate Design for Residential Electricity Customers, April 2, 2015.
[63] Ontario Energy Board, Framework for Energy Innovation: Setting a Path Forward for DER Integration, January 2023.
[64] Exhibit M1, p. 75.
[65] Ontario Energy Board, Framework for Energy Innovation: Setting a Path Forward for DER Integration, January 2023, pp. 38-41.
[66] EB-2024-0118, Non-Wire Solution Guidelines for Electricity Distributors, March 28, 2024.

were billed on a bi-monthly basis).[67] This operated to reduce billing lag and related cost recovery.

- In 2023, the OEB issued the preliminary Uniform Transmission Rates (UTRs) earlier in the year to allow distributors to capture the most up-to-date costs to include in the Retail Transmission Service Rates (RTSRs) to be billed to customers. This will decrease amounts accumulated in variance accounts[68] and reduce regulatory lag.
- In 2023, the OEB changed its policy to allow for the recovery of changes to low voltage service costs through the annual update to low voltage service rates.[69]

CCC notes that regulatory lag is an important consideration regarding regulatory risk[70] and the OEB's policy changes since 2009 have operated to reduce regulatory lag, which decreases risk for Ontario's distributors.

CCC submits that the result of the OEB's policy changes since 2009 has been a significant reduction to the risk faced by Ontario's electricity distributors and transmitters. While, in terms of quantum, most of the policy changes were directed at electricity distributors, the most significant changes, including the availability of a Custom IR framework for ratemaking, are available to transmitters. Hydro One is benefitting from the use of the Custom IR option (inclusive of cost recovery of forecast capital costs in each year of the term and the availability of an externally driven capital variance account), which underpins its 2023-2027 rate framework.[71]

CCC notes that the OEB's regulatory framework has resulted in revenue stability between 2015-2022 for Ontario's electricity distributors (in terms of revenue per customer) and even during the COVID-19 pandemic Ontario's distributors maintained strong cost recovery.[72]

In addition, S&P Global, in its assessment of U.S. and Canadian regulatory regimes[73] in 2023 classified Ontario as a "most credit supportive" jurisdiction.[74] This is an important

[67] EB-2014-0198, Ontario Energy Board, Notice of Amendment to the Distribution System Code, April 15, 2015.
[68] EB-2023-0222, 2024 Preliminary UTRs, September 28, 2023.
[69] Ontario Energy Board, Updated Filing Requirements for Electricity Distribution Rate Applications, Chapter 3, June 15, 2023.
[70] Exhibit M3, p. 24.
[71] EB-2021-0110, Hydro One Joint Rate Application, Settlement Proposal, October 24, 2022, pp. 25-26.
[72] Exhibit M1, p. 75.
[73] The assessment is based on an analysis of regulatory stability, tariff-setting procedures, financial stability, and regulatory independence.
[74] S&P Global Ratings, North American Utility Regulatory Jurisdictions: Some Notable Developments, November 10, 2023.

indicator that the OEB's regulatory framework is operating to reduce the risk faced by Ontario's utilities (as viewed by rating agencies). A 2023 DBRS credit rating for Hydro One stated that that the OEB's regulatory regime permits it a reasonable opportunity to recover operating and capital costs, and to earn the approved ROE. Further, DBRS views the utility regulatory framework in Ontario as transparent and supportive for regulated transmission and distribution operators.[75]

Overall, the OEB's regulatory framework for Ontario's distributors and transmitters is favourable to the utilities. The changes to regulatory policy since 2009 have further de-risked Ontario's distributors and transmitters since the last time that the OEB set the base ROE. The policy changes since 2009 also highlight that the OEB is a proactive regulator. If it sees potential problems on the horizon for utilities in terms of cost recovery and regulatory certainty it moves to address those issues (whether that is through changes to the ratemaking frameworks available, the establishment of new generic deferral accounts, etc.). This is important to investors when looking at their investment opportunities as the regulatory framework that a utility operates within is an extremely important aspect in terms of the evaluation of risk. The changes to regulatory policy made by the OEB reflect a very substantial decrease to risk that should be considered when setting the ROE in the current proceeding.

CCC also submits that there is no reason to believe that the OEB's proactive approach to regulation is going to change in the future. The OEB recently held its 2024 policy day where it sought input from stakeholders on emerging issues and previewed the work it is doing on various matters (including "A Rate-Setting Framework for the Future," which is aimed at further supporting utilities to cost-effectively meet the demands of the energy transition).[76] Policy day highlights the OEB's continued proactive approach to addressing matters that are important to Ontario utilities going forward.

Energy Transition Risk

As LEI noted, the term "energy transition" refers to a shift from an energy system that primarily relies on fossil fuel-based energy sources (such as natural gas, coal and oil) to net zero-emitting renewable energy sources (such as batteries, solar and wind power, and carbon capture and storage). LEI further stated that electrification of heating and

[75] DBRS Morningstar. Rating Report: Hydro One Limited. November 20, 2023.
[76] 2024 Policy Day Materials, October 16, 2024.

transportation is often a large part of such policies, with impacts on regulated utilities in both the electricity and natural gas sectors.[77]

As noted previously, energy transition is impacting electricity distributors and transmitters differently than Enbridge Gas. The OEB already determined that energy transition is increasing the risk faced by Enbridge Gas.[78] The potential for declining new customer connections, fuel switching away from natural gas and related stranded asset risk are all issues that operate to potentially increase the risk for Enbridge Gas.

CCC submits that the same cannot be said for Ontario's electricity distribution and transmission companies. Energy transition is expected to increase demand for electricity through electrification policies. As noted by Concentric, new electricity transmission infrastructure will be necessary, and the most cost-effective way, to support the growing electricity demand. Concentric also stated that in Ontario alone, gross capital spending across electric distributors increased from $1.8 billion annually in 2012 to over $2.5 billion annually in 2022 highlighting the sector's increasing need for both capital spend and recovery. This increase is reasonably expected to continue in the short to long term as a consequence of energy transition.[79] There is no new risk of stranded assets for electricity distributors and transmitters as their systems are expected to grow (and not decline).

Demand growth is properly considered an opportunity for electricity distributors and transmitters. As noted by Dr. Cleary, "an expected increase in demand represents a growth opportunity for utilities and is a situation that most companies would happily embrace – far preferable to a forecast decrease in demand for their product. This is particularly true when the companies have the opportunity to adequately plan for such increases in demand, and can pass through legitimate costs to consumers (as is the case for regulated operating utilities)."[80]

CCC submits that Ontario's electricity distributors and transmitters have the ability to recover all prudently incurred costs. In addition, in terms of any lag with respect to cost recovery, the OEB has already made available regulatory mechanisms for the recovery of capital costs on a forecast basis. Therefore, demand growth and related capital spending does not increase the risk faced by Ontario's electricity distributors and transmitters. CCC agrees with LEI that regulated entities face less risk than competitive businesses and

[77] Exhibit M1, p. 43
[78] EB-2022-0200, Decision and Order, December 21, 2023, p. 68.
[79] Exhibit M2, pp. 22-23.
[80] Exhibit N-M4-CCC-9.

existing regulatory mechanisms address load fluctuations, capital recovery, and unforeseen events, whether caused by energy transition or not.[81]

Nexus makes the statement, in its report, that "other jurisdictions embracing carbon reduction and electrification policies have amended their regulatory mechanisms recognizing that the trajectory of capital spending may be uncertain. The absence of these policy changes in Ontario increases the risk to which distributors are exposed."[82] CCC submits that the OEB has the necessary mechanisms in place for capital cost recovery already. And in line with the OEB's proactive approach to regulation is already looking at "A Rate-Setting Framework for the Future," which is aimed at further supporting utilities to cost-effectively meet the demands of the energy transition.[83]

Overall, in the context of the current regulatory framework applied to Ontario's distributors and transmitters, along with the OEB's proactive approach to regulation, it is clear that energy transition is not increasing the risk faced by these companies.

Concentric's Other Perceived Risks – Climate Change and Cyber Security

In its report, Concentric suggests that climate and cyber security risks are intensifying the business risks faced by the regulated utility industry.

With respect to climate risk, Concentric stated that the utility industry faces the highest combined physical risk from climate hazards, which are increasing in their intensity and frequency because of rising temperatures. Increased risk from wildfires, severe weather events, flooding, and rising water temperatures create new and likely ongoing financial and operational challenges for utilities to ensure timely recovery from these events while seeking to proactively safeguard their assets from future climate impacts.[84]

CCC submits that climate risk is mitigated through prudent planning by utilities. The OEB has already established a consultation to address system vulnerabilities related to climate. In this consultation, the OEB is seeking to develop an approach whereby:

- Climate resilience is incorporated into asset and investment planning activities

[81] Exhibit M1, p. 44.
[82] Exhibit M3, p. 28.
[83] 2024 Policy Day Materials, October 16, 2024.
[84] Exhibit M2, p. 111.

- Regular assessments are undertaking related to vulnerabilities and operations in the event of severe weather
- Customer value is prioritized when investing in system enhancements for resilience purposes.[85]

While the outcome of this consultation is not known, the OEB appears to be moving towards the mandatory inclusion of climate-related risks in system planning. This will mean that utilities will be encouraged to include system hardening-related projects in their capital plans. The OEB will review those plans for prudence and related cost recovery allowance. CCC also notes that utility capital plans can already include projects related to system hardening (or more generally reliability), the utility would simply have the onus to explain why any given project is needed and should be approved for cost recovery.

In addition, all electricity distributors and transmitters have Z-factor availability. The Z-factor mechanism is designed for cost recovery related to extraordinary events that are outside of the utilities control.[86] Z-factor claims that are filed with the OEB are often related to storm damage.[87]

CCC submits that climate change, including the related increase to climate hazards, will have an impact on Ontario's electricity distribution and transmission companies. However, the OEB's policies, as set out above, have, and will continue to, mitigate those risks. Therefore, there is no meaningful increase in the risk faced by these companies due to climate change.

With respect to cyber security, Concentric stated that utilities face a heightened risk from cyber security breaches, in addition to the typical risks borne by all other sectors (e.g., personal information and data breaches, ransomware attacks, etc.). The urgency to upgrade legacy systems is felt more severely by utilities, as reflected in the OEB's evolving cyber security requirements. Concentric further stated that utilities are also increasingly expected to invest in technological upgrades to better manage their assets and operations, but these advancements may complicate or increase the cost of cyber security readiness. Cyber security issues are a critical issue for utilities and regulators.[88]

[85] OEB Letter, Vulnerability Assessment and System Hardening Project, July 27, 2024.
[86] OEB Chapter 3 Filing Requirements, June 18, 2024, p. 21.
[87] For example, EB-2022-0317, Elexicon Energy Inc., June 15, 2023, Decision and Order, p. 1. Elexicon applied for and was granted cost recovery for restoration costs associated with a major windstorm that occurred in its service area on May 21, 2022.
[88] Exhibit M2, p. 121.

CCC submits that the OEB has, and continues, to provide clear guidance on its expectations around cyber security. In 2023, the OEB issued the Ontario Cyber Security Framework that is used by electricity transmitters and distributors to assess and report their cyber security capabilities to the OEB.[89] In 2024, the OEB issued a letter discussing an initiative to enhance cyber security readiness in Ontario's electricity sector through further reporting.[90]

CCC submits that Ontario's electricity distributors and transmitters are expected to plan for and enhance their cyber security readiness in the context of OEB policy. Costs associated with cyber security enhancement and readiness are recoverable from ratepayers assuming those costs are prudently incurred. For example, Toronto Hydro in its 2025-2029 rates application, sought recovery of forecast IT capital costs, which included costs associated with cyber security.[91]

Similar to climate risks, the OEB's regulatory policies mitigate cyber security risks (and the associated risk of non-recovery of costs). Therefore, there is no meaningful increase in the risk faced by these companies due to cyber threats.

Financial Risks

LEI stated that the assessment of financial risks by the OEB has focused on the utility's ability to continue to attract debt and equity financing at reasonable terms. A widely followed approach to evaluating financial risk is to assess key credit metrics and their potential impact on credit ratings.[92]

As noted previously, since at least 2009, Ontario utilities have had no issues attracting debt and equity financing at reasonable terms. This is confirmed by LEI, Concentric and Nexus. LEI also stated that "Ontario utilities have been able to raise capital at reasonable terms since 2006, which is one of the best indicators that FRS is being met." [93] Similarly, Concentric stated that it "is not aware of Ontario utilities failing to attract capital or being in danger of losing their financial integrity since the 2009 Decision…"[94] In addition, Nexus

[89] Ontario Cyber Security Framework | Ontario Energy Board (oeb.ca).
[90] OEB Letter, Enhancing Cyber Security Readiness in Ontario's Electricity Sector, October 7, 2024.
[91] EB-2023-0195, Exhibit 2B, Section E8.4.
[92] Exhibit M1, p. 55.
[93] Exhibit N-M1-11-OEA-12.
[94] Exhibit N-M2-10-CME-1.

stated that it is unaware of any reported expressions of concern from credit rating agencies regarding the ability of Ontario utilities to recover costs over the next 5 years.[95]

For the Ontario distributors and transmitters that have credit ratings available, the average S&P Global credit rating is A.[96] S&P Global describes its credit ratings as forward-looking opinions about an issuer's creditworthiness. With respect to an "A" rating, S&P Global states that this implies a "strong capacity to meet financial commitments, but somewhat susceptible to economic conditions and changes in circumstances."[97] CCC submits that the very strong credit ratings for all electricity distributors and transmitters, for which ratings are available, reinforces the strong financial position these companies are currently in (and are expected to be in the future).

CCC recognizes that reductions to the approved ROE and/or equity thickness could impact future financial assessments. However, the OEB should continue to monitor any changes that do occur (including the monitoring of credit ratings) as discussed in section 6.3 of the submission.

For the reasons discussed above, CCC submits that the risks faced by Ontario's distributors and transmitters decreased since 2009. The changes to regulatory policy and the OEB's proactive approach to regulation de-risked utilities over the past 15 years. Distributors and transmitters have more protection than ever with respect to the recovery of costs during ratemaking terms (e.g., ability to recover forecast capital costs (Custom IR, ICM/ACM), ability to recover numerous categories of non-forecast costs or cost variances on forecast costs (DVA expansion), move to fixed charges for residential customers, etc.). Regulatory lag has also been significantly decreased (through changes to UTR policy, billing practices, etc.). Due to the OEB's favourable regulatory framework applicable to Ontario's distributors and transmitters, energy transition, climate and cyber security risks are not negatively impacting the risk profile of these companies.

Based on CCC's premise that the ROE established by the OEB in 2009 is already too high and the risk faced by Ontario's distributors and transmitters has only decreased since that time, the next question that needs to be answered is what is the appropriate ROE going forward? In section 3.3, CCC discusses the various estimation approaches and resulting estimates suggested by the experts (including a discussion of the benefits and flaws). In

[95] Exhibit N-M3-2-OEB Staff-31.
[96] Exhibit N-M2-CCC-9 and Exhibit N-M3-10-SEC-72 (Attachments). The average includes: Alectra Inc., Hydro One, Toronto Hydro, Grandbridge Energy Inc., and Londo Hydro Inc.
[97] Understanding Credit Ratings | S&P Global Ratings.

section 3.4, CCC sets out the rationale for its proposed base ROE of 7.1% for Ontario's electricity distributors and transmitters.

3.3. Methodologies for Estimating Return on Equity

CCC summarizes the estimation approaches and resulting estimates provided by the four experts in the table below.

Summary of Expert Estimation Approaches and Resulting Estimates of Base ROE

	Concentric[98]	Nexus[99]	LEI[100]	Dr. Cleary[101]
Proxy Group	Majority U.S.	Majority U.S.	Majority U.S.	Canadian (only used for DCF)
DCF	• Current market data • Analyst growth rate but using multi-stage DCF	• Current market data • Analyst growth rate in single-stage model	Not part of recommendation	• Average market data • Sustainable growth
CAPM	• Forecast U.S. & Canada risk-free rate • Adjusted betas • Historical U.S. & Canada MRP	• Forecast U.S. risk free rate • Adjusted betas • Forecast MRP	• Forecast Canada risk-free rate • Raw Beta • Historical U.S. MRP	• Current Canada risk-free rate • Long-term average Canada betas • Multiple approaches for MRP
Risk Premium	• U.S. and Canada Authorized ROEs	• U.S. Authorized ROEs	Not part of recommendation	• Bond Yield Plus Risk Premium
Transaction / Flotation Costs	50 bps	50 bps	0 bps	50 bps
Recommended Base ROE	10%	11.08%	8.95%	7.05%
Post-Hearing - Updated Recommended Base ROE	10%[102]	11.08%[103]	8.88%[104]	6.95%[105]
Implied Equity Risk Premium (ERP) of Updated Recommended Base ROE (using LEI's Risk-Free Rate)[106]	6.87%[107]	7.95%[108]	5.75%	3.82%

[98] Exhibit M2, pp. 57-84 and OEA ROE Working Papers.
[99] Exhibit M3, pp. 38-79 and Exhibit M3-NAICS 2211 v04 (as filed).
[100] Exhibit M1, pp. 116-122.
[101] Exhibit M4, pp. 85-113.
[102] Undertaking J4.8. The North American combined proxy group ROE has reduced to 9.9% but Concentric maintained its 10% recommendation.
[103] Undertaking J5.2.
[104] Undertaking J2.2.
[105] Undertaking J5.3.
[106] Ontario Energy Board, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, p. 26. The OEB stated that the ROE produced by various approaches can be expressed as an absolute ROE number or as an ERP over a risk-free rate. Also, expressing the ROE in terms of a premium above the long-term Canada bond yield does not mean that the initial ROE needs to be estimated by using a single test or a number of tests that can be defined as ERP tests. For comparison purposes, similar to the manner that the figures were shown in the 2009 Cost of Capital Report, we have applied the 3.13% risk-free rate set out in Undertaking J2.2 (LEI's updated base ROE recommendation) to determine the implied ERP from the expert's recommendations.
[107] Exhibit M2, p. 100. Concentric views the implied ERP from its base ROE recommendation to be 6.19% as it uses an average U.S. and Canada long-bond estimate of 3.8% (i.e., 10%-3.8% = approximately 6.2%).
[108] Exhibit M3, p. 39. The implied ERP from Nexus' base ROE recommendation, using its risk-free rate based on a 30-year U.S. Treasury bond yield of 4.06%, would be 7.02% (i.e., 11.08%-4.06% = 7.02%).

	Concentric	Nexus	LEI	Dr. Cleary
Application of Recommended ROE	Electricity distributors and transmitters and natural gas distributors	Electricity distributors	All rate regulated utilities	All rate regulated utilities
Equity Thickness	45% for electricity distributors and transmitters and natural gas distributors	No change for electricity distributors	No change for all rate regulated utilities	• Reduce Enbridge Gas to 36% • Reduce Hydro One to 38% (with further reductions to 36% in future years

CCC notes that, with the exception of Dr. Cleary, all of the experts are recommending increases relative to the implied ERP of 5.5% (or 550 basis points) that was established in 2009. Concentric, Nexus, and LEI are all suggesting ROEs that are far higher than the level necessary to meet the fair return standard and an ROE established at any of these levels will perpetuate the payment of economic rent to utilities by ratepayers.

At a high-level, it is the experts' reliance on U.S. market data and an incompatible group of proxy companies, which they use as comparators for the Ontario utilities, that results in the excessive ROE estimates. There are other problematic inputs and model specifications as well.

Before discussing the details of the individual proxy groups and model specifications applied by each expert, it is important to consider, more generally, the U.S. capital market and its relevance to the financing of Ontario's utilities.

Concentric, Nexus and LEI are all relying heavily on U.S. market data in their estimation approaches. They have all included U.S. firms in their proxy groups and use U.S. market data to calculate the recommended base ROEs in their various estimation approaches. They support their decisions to use U.S. market data with commentary regarding the integration of Canadian and U.S. capital markets. For example, Nexus stated that "Ontario and US electric service providers compete in the same market for capital."[109] It also stated that "capital from US exchanges is equivalent to capital from Canadian exchanges."[110] Concentric stated that "Ontario operates in a North American economy, utilities industry, and capital market."[111] These experts are ignoring the heavy bias towards Canadian investments that Canadian investors have in the weighting that they apply towards U.S. firms and U.S. market returns.

[109] Exhibit M3, p. 38.
[110] Exhibit M3, p. 43.
[111] Concentric Presentation Day Materials, p. 6.

LEI, which did not include Canadian market returns in its CAPM-derived base ROE recommendation, appears to acknowledge the home bias in commenting that the eight major pension funds in Canada (informally known as the Maple 8) allocate approximately 25% of their portfolio to domestic Canadian investments.[112]

Dr. Cleary further describes the extent of home bias amongst Canadian investors. He stated that a broader representation of home bias, which extends beyond just the eight largest Canadian pension funds, shows that Canadian investors (including institutions) had a domestic allocation to Canadian equities of over 40% in 2020 (i.e., over 13 times the Canadian equity market's global market weight of 3%). Dr. Cleary further stated that the home bias is even more dramatic in Canadian fixed income markets, which also comprise about 3% of global fixed income markets, but Canadian investors had a domestic allocation for Canadian fixed income of approximately 84% (i.e., approximately 28 times the Canadian fixed income market's global market weight).[113]

Dr. Cleary also explained that U.S. yields have been higher than Canada yields for several years, and that this is still the case. For example, U.S. 30-year yields are about 1.1% higher than Canadian yields. Therefore, Canadian utilities would obviously elect to borrow funds in Canada due to lower rates and avoiding currency risk.[114] This implies that Concentric, LEI and NEXUS are overstating the integration of the Canadian and US markets. As another example of the separation of Canadian and U.S. markets, at the oral hearing, Commissioner Sardana raised a recent debt issuance by Hydro One where it offered $1.2 billion of medium-term notes only in Canada (and it was specifically not an offer to sell in the U.S.).[115]

In addition, the actual shareholders of the majority of Ontario distributors are municipalities. These municipalities have an even more pronounced home bias relative to the general population of Canadian investors. Municipalities hold the vast majority of their investments in Canadian markets.[116]

Finally, CCC has had the benefit of reviewing the Association of Major Power Consumers in Ontario (AMPCO) & Industrial Gas Users Association (IGUA) draft submission with respect

---

[112] Exhibit M1, p. 120.
[113] Exhibit N-M4-0-SEC-83.
[114] Exhibit N-M4-12-Staff-72.
[115] Oral Hearing Transcripts, Volume 5, p. 144; and [Hydro One Inc. Prices Offering of $1.2 Billion Medium Term Notes under Sustainable Financing Framework].
[116] Exhibit K2.2, pp. 17, 54 and 101. For example, the City of Ottawa has, at least, 85% of its investments in Canadian assets and the City of Greater Sudbury has all of its investments in Canadian assets.

to Ontario's municipally owned distributors involvement in equity capital markets. We agree with and support their position, and detailed analysis, that, due to existing tax law, these utilities cannot accept non-municipal capital from anywhere (whether that be from Canada, the U.S., or elsewhere) in any material amount without incurring a significant departure tax. Therefore, U.S. capital markets are very clearly not applicable to Ontario's municipally owned distributors.

CCC submits that the OEB should take into account the home bias of Canadian investors and the tax law applicable to Ontario's municipally owned distributors when considering the appropriate base ROE estimate in the fulfillment of the fair return standard (and in evaluating the recommendations of the experts).

Concentric's Estimation of the Base ROE

Concentric arrives at its base ROE estimation of 10% (which includes a transaction cost adder of 0.5%) by averaging the results of its DCF, CAPM and Risk Premium approaches for the North American proxy group.[117] Concentric proposed that its base ROE be applied to Ontario's electricity distributors and transmitters and natural gas distributors. As discussed previously, CCC submits that the ROE established in this proceeding should apply to only electricity distributors and transmitters.

Proxy Group

Concentric's proxy group is used directly as part of its DCF and CAPM estimations of the base ROE. Concentric provides both North American electric and North American natural gas peer groups in its report (a total of 25 companies with 76% of the companies being U.S. firms).[118]

Concentric states that as the "ROE is a market-based concept, it is necessary to establish a group of companies that is both publicly traded and comparable to Ontario's utilities in fundamental business and financial respects to serve as a "proxy" for purposes of ROE estimation."[119] Concentric further states that any determination on the appropriate base ROE "must be based on an assessment of the company-specific risks relative to the proxy group and the use of informed judgement."[120]

[117] Exhibit M2, pp. 9-10.
[118] Exhibit M2, pp. 49-50.
[119] Exhibit M2, pp. 45.
[120] Exhibit M2, pp. 45.

In its 2009 Cost of Capital Report, the OEB described this exercise of comparing utilities by stating that, "the comparable investment standard requires empirical analysis to determine the similarities and differences between rate-regulated entities. It does not require that those entities be "the same"."[121] The OEB states that the comparable enterprises used in the fulfillment of the comparable investment standard should be of "like" risk.[122]

CCC submits that Concentric's peer group cannot be said to reflect companies that are "the same" nor are they even "like" Ontario electricity distributors and transmitters and natural gas distributors. We focus on Concentric's North American electric proxy group in our argument but submit that Concentric's North American natural gas proxy group is no better than its electricity proxy group.

Concentric relies heavily on U.S. holding companies as part of its North American electric proxy group. In fact, 80% of Concentric's North American electric proxy group is comprised of U.S. firms.[123] This implies a determination (or an application of judgement) by Concentric, that U.S. electric utilities and Ontario electric utilities have similar risks. This is not a reasonable conclusion.

As noted by Dr. Cleary, U.S. utilities are not reasonable comparators for Canadian utilities. U.S. utilities have significantly higher business risk due to their holding company structure (and related holdings) and due to the nature of their operations. Dr. Cleary also shows that historical U.S. utility beta estimates, which are an indicator of risk, over a long period of time are significantly higher than Canadian beta estimates.[124] Therefore, the reliance on U.S. comparators is flawed and leads to base ROE estimates that are much higher than what would be appropriate for rate-regulated electric distributors and transmitters in Ontario.

Reviewing the companies that form Concentric's North American electric proxy group more closely, CCC notes that the majority of the companies are vertically integrated and own

[121] Ontario Energy Board, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, p. 21.
[122] Ontario Energy Board, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, p. 21.
[123] Exhibit M2, p. 49.
[124] Exhibit M4, p. 29.

significant generation assets.[125] As the School Energy Coalition (SEC) showed at the oral hearing, the amount of generation owned by the companies in Concentric's proxy group is significant. For example, Concentric's proxy group includes Alliant Energy Corporation, NextEra Energy Corporation, Pinnacle West Capital Corporation, and Southern Company all of which have generation assets that are, at least, 50% of their asset bases.[126] Some of the companies in Concentric's peer group also own significant coal-fired generation assets[127] that CCC submits will be impacted more acutely by energy-transition related policies.

Electric companies that own generation assets have significantly higher risk than Ontario's distributors and transmitters that own no regulated generation assets. Concentric, itself, acknowledges this fact. In the current proceeding, Concentric proposes that the ROE established in this proceeding should not apply to OPG as "OPG faces a different and heightened level of risk to distributors and transmitters."[128] In previous reports filed with the OEB, Concentric stated that the "generation function is generally regarded by investors as being higher risk than electric transmission or distribution."[129] And, in the same report, Concentric quoted a Moody's report noting that:

> "generation utilities and vertically integrated utilities generally have a higher level of business risk because they are engaged in power generation… We view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delay."[130]

In addition, Concentric's North American electric proxy group includes two firms with material unregulated business operations.[131] CCC submits that unregulated business operations are generally riskier than regulated business operations. This was confirmed by LEI at the oral hearing.[132]

---

[125] Undertaking J3.2 – 80% of the companies in Concentric's North American electric proxy group own material amounts of generation assets.
[126] Oral Hearing Transcripts, Volume 2, pp. 156-166, 194; and Exhibit K2.6, pp. 184, 195, 196, 198.
[127] Oral Hearing Transcripts, Volume 2, p. 160; and Exhibit K2.6, p.186 (Ameren Corporation), p. 190 (Duke Energy), and p. 200 (Xcel Energy).
[128] Exhibit M2, p. 42.
[129] EB-2020-0290, Exhibit C1-1-1, Attachment 1, p. 63.
[130] EB-2020-0290, Exhibit C1-1-1, Attachment 1, p. 63.
[131] Exhibit N-M2-CCC-4, Attachment 1, p. 1. Canadian Utilities Limited (8% of operating revenue is from unregulated businesses) and NextEra Energy Inc. (12% of operating revenue is from unregulated businesses).
[132] Oral Hearing Transcripts, Volume 2, p. 54.

The Canadian firms that form part of Concentric's North American electric proxy group are Canadian Utilities Limited, Emera Inc., Fortis Inc., and Hydro One. CCC notes that both Emera Inc. and Fortis Inc. own significant generation assets[133] and Canadian Utilities Limited derives 8% of its income from unregulated operations.[134] This leaves only Hydro One as a reasonable comparator.

Further, Concentric acknowledged the importance of regulatory risk in determining the business and financial risks of Ontario's utilities relative to the operating utilities in its peer group.[135]

In response to an interrogatory, Concentric provided its "proxy group regulatory risk assessment," which provided some information about the ratemaking frameworks applicable to operating companies in Concentric's peer group.[136] Concentric stated that it did not study and does not know precisely how the various mechanisms operate in the peer jurisdictions.[137] This is problematic as Concentric is using these peers as reasonable comparators directly in the estimation of the ROE for Ontario's utilities (and as previously discussed, regulatory risk plays a very important role in evaluating the risks faced by regulated firms).

The "proxy group regulatory risk assessment" does provide some information where CCC understands the regulatory mechanisms that are referenced as being applicable to the companies operating in the peer jurisdictions.

First, the majority of the North American electric proxy group have either a historical or partially forecasted test year.[138] This increases regulatory lag relative to a fully forecasted test year, which is the basis for setting rates in Ontario.[139]

Second, with respect to the decoupling mechanisms that are applicable to the companies in Concentric's North American electric proxy group, only 11% have full decoupling mechanisms (excluding Hydro One) and only 38% have partial decoupling mechanisms.[140]

---

[133] Undertaking J3.2, Attachment 1.
[134] Exhibit N-M2-CCC-4, Attachment 1.
[135] Exhibit M2, p. 125.
[136] Exhibit N-M2-CCC-4, Attachment 2.
[137] Oral Hearing Transcript, Volume 4, pp. 42-43.
[138] Exhibit N-M2-CCC-4, Attachment 2, p. 3. Only 30% of the operating companies in the North American electric proxy group have a fully forecasted test year (excluding Hydro One).
[139] Exhibit M2, p. 126.
[140] Exhibit N-M2-10-SEC-51, Attachment 1.

While Concentric is not certain of the design of the mechanisms actually used in each jurisdiction,[141] the definition of full and partial decoupling is illustrative:

> "A decoupling mechanism enables utilities to offset the effect on revenues of fluctuations in sales caused by customer participation in energy efficiency programs, deviations from "normal" temperature patterns or economic conditions. [Regulatory Research Associates] considers a decoupling mechanism that adjusts for these factors to be a "full" decoupling mechanism and designates those that address only one or two of these factors as "partial" decoupling mechanisms. [Regulatory Research Associates] also assigns a partial decoupling tag to those mechanisms that include rate caps or other limitations."[142]

CCC notes that Ontario distributors would be classified as having a full decoupling mechanism due to the fully fixed distribution rates for residential customers.[143] Therefore, Ontario's distributors face less revenue risk than 89% of the operating companies in the North American electric peer group.

In addition, as discussed previously, Ontario's distributors and transmitters have access to mechanisms for the recovery of costs during ratemaking terms (e.g., ability to recover forecast capital costs (Custom IR, ICM/ACM). Also, the OEB allows for the recovery of numerous categories of non-forecast costs, or cost variances on forecast costs, during ratemaking terms that may not be available in other jurisdictions through established generic or utility-specific DVAs. Furthermore, the OEB is classified as a "most credit supportive" jurisdiction by S&P Global.[144]

Concentric defends its peer group selection through claims that removing companies that own regulated generation or operate unregulated businesses result in small peer groups that "produce results that are less reliable and less statistically robust."[145] CCC submits that the use of a statistically robust peer group (i.e., large peer group) comprised of firms that are not "like" Ontario distributors and transmitters in the estimation of the base ROE does not lead to an accurate result. As Dr. Cleary stated, "…it is not helpful to have a larger sample that does not include representative comparators, which is the focus of establishing proxy groups. Comparing applies to more oranges doesn't help."[146]

---

[141] Exhibit N-M2-10-SEC-51, part (a).
[142] Undertaking J4.4.
[143] EB-2012-0410, Ontario Energy Board Policy, A New Distribution Rate Design for Residential Electricity Customers, April 2, 2015.
[144] S&P Global Ratings, North American Utility Regulatory Jurisdictions: Some Notable Developments, November 10, 2023.
[145] Exhibit J3.2, p. 1.
[146] Exhibit N-M4-10-OEB Staff-67.

CCC submits that Concentric's North American electric proxy group is not relevant to the estimation of the base ROE for Ontario's distributors and transmitters as the peers have significantly higher risk. Therefore, the results from its DCF and CAPM estimates should be disregarded on the basis of the proxy group alone. There are also problems with the model specifications that further call into question the base ROE recommendation, which are discussed below.

DCF Approach

Concentric's multi-stage DCF analysis relies on its selected proxy group and results in a base ROE of 9.83% (or 9.43% as updated) for the North American electric proxy group.[147] As the peer group is almost entirely comprised of peers that are riskier than Ontario distributors and transmitters and the financial information from these peers is a direct input to the DCF model, the output of that model is, by definition, going to be incorrect.

In addition, the growth estimates used in Concentric's DCF analysis are based on analyst growth forecasts. As Dr. Cleary noted, analyst estimates are known to be overly optimistic and will lead to invalid estimates of the base ROE when using DCF models. Dr. Cleary cited a study[148] that estimates that the "optimism" bias in analysts' growth forecasts inflates final DCF cost of equity estimates by an average of 2.84%.

Dr. Cleary further stated that, Concentric, in its multi-stage DCF model, assumes that the analyst growth rates, which are higher than nominal GDP growth, exist for 5 years. These growth rates then decline over the following 5 years to a stable long-term growth rate equal to Concentric's estimate of long-term nominal GDP growth.[149] Therefore, Concentric's multi-stage DCF model assumes that utilities' earnings and dividends will grow at rates above nominal GDP growth for 10 years. Dr. Cleary stated that this is not a realistic assumption for mature, stable operating utilities.[150] CCC agrees with Dr. Cleary's concerns regarding the specifications of Concentric's DCF model. The result is that Concentric's

[147] Exhibit M2, p.9; and Undertaking J4.8.
[148] Easton, Peter D., and Gregory A. Sommers, "Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts, Journal of Accounting Research 45 no. 5, December 2007, pp. 983-1016.
[149] Concentric Working Papers, Exhibit CEA-5. Concentric's growth rate starts at 6.01% for 5-years (for the North American electric proxy group), reduces over the next 5-years (an average growth rate of 5% in that period), then declines to 4% in perpetuity.
[150] Exhibit N-M4-0-SEC-82, pp. 2-3.

DCF-derived ROE is significantly overstated for application to Ontario distributors and transmitters.

CAPM Approach

Concentric's CAPM approach results in a base ROE of 10.23% (or 10.21% as updated) for the North American electric proxy group.[151] CCC is concerned with many of the decisions that Concentric made with respect to its CAPM model specifications.

First, Concentric's risk-free rate is a combination of a 30-year Canadian government bond yield and a 30-year U.S. treasury bond yield. More specifically, Concentric uses the Canadian government bond yield for Canadian firms in its proxy group and the U.S. treasury bond yield for US firms in its proxy group.[152] CCC submits that the risk-free rate for Canadian investors is properly reflected by the 30-year Government of Canada bond yield. Concentric, itself, is recommending the use of the 30-year Government of Canada bond yield as the risk-free rate in the annual ROE adjustment formula and as part of the determination of the Deemed Long-Term Debt Rate (DLTDR).[153] In addition, the OEB currently uses the 30-year Government of Canada bond yield (as reflected by the 10-year bond yield plus a spread for the 30-year bond yield) in the annual ROE adjustment formula and the DLTDR (and it was used in the initial establishment of the base ROE in 2009).[154] CCC submits that applying a different yield for the risk-free rate in the CAPM model relative to the annual adjustment mechanism and the DLTDR calculation has no merit.

Second, Concentric's peer group is the basis for the adjusted betas used in its CAPM model. The North American electric proxy group has an average adjusted beta of 0.89, which is directly used in the calculation of the CAPM-derived ROE estimation.[155] CCC submits that, as the companies in Concentric's proxy group are riskier than Ontario's distributors and transmitters for all the reasons previously discussed, the average beta estimate used in its CAPM model will be overstated. CCC notes that Hydro One (being the only OEB rate-regulated company in the peer group) has an adjusted beta of 0.69,[156] which

[151] Exhibit M2, p.9; and Undertaking J4.8.
[152] Concentric Working Papers, Exhibit CEA-7.3. Concentric uses a risk-free rate of 3.46% for Canadian firms and risk-free rate of 4.14% for U.S. firms.
[153] Exhibit M2, pp. 38, 95.
[154] Ontario Energy Board, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, Appendix B and C. Specifically, the OEB states that "the ROE and the deemed long-term debt rates are based on the same forecast of the risk-free rate."
[155] Exhibit M2, p. 66.
[156] Exhibit N-M2-CCC-4, Attachment 1.

is significantly below the average adjusted beta of 0.89 for the peer group that is used in the model.

CCC also submits that Concentric's use of adjusted betas (as opposed to raw betas) is inappropriate. The use of adjusted betas is based on the premise that utility betas move towards the average beta of 1.0 over time. As discussed by Dr. Cleary, in some detail, there is strong evidence that utility betas do not move towards 1.0. Dr. Cleary cited a number of recent studies that show that utility betas do not have a tendency to move towards 1.0.[157] For example, Dr. Cleary cited a 2022 article by Thomas Sikes that notes "[i]t is undeniable based on Figure IV that the Value Line Adjustment is inappropriate. Clearly, utility betas have been consistently below 1.0…"[158] CCC notes that Concentric uses Value Line adjusted betas in its calculation of the CAPM-derived ROE.[159] The impact of the adjustment on average is to increase the average raw beta from 0.84 to an adjusted beta of 0.89.[160] Using Hydro One, as an example, the impact of the adjustment is to increase the raw beta from 0.54 to an adjusted beta of 0.69.[161] As a measure of the materiality of the use of an adjusted beta of 0.89, if a raw beta of 0.5 was instead applied (which is very close to the beta for the only Ontario rate-regulated utility that is included as part of the North American electric peer group), the CAPM-derived ROE reduces from 10.23% to 7.71%.[162]

Finally, with respect to the historical MRP that Concentric applies in its CAPM model, CCC submits that Concentric's use of U.S. market data biases the MRP upwards.[163] In addition, Dr. Cleary stated that the data that Concentric uses, for both the determination of the Canadian and U.S. historical MRPs, are higher than he would expect based on recent studies.[164]

Risk Premium

Concentric's Risk Premium approach results in a recommended base ROE of 9.9% (or 9.83% as updated) for the North American electric proxy group.[165] CCC notes that

[157] Exhibit N-M4-0-SEC-82, pp. 3-4.
[158] Exhibit M4, p. 136; and Exhibit M4, Attachment AF, Thomas Sikes, Regulated Inequity, January 2022.
[159] Exhibit M2, p. 66. More specifically, Concentric takes an average of Value Line and Bloomberg betas (which are both adjusted in the same manner) in its calculation of the CAPM-derived ROE.
[160] Undertaking J4.1.
[161] Exhibit N-M2-CCC-4, Attachment 1.
[162] Exhibit N-M2-CCC-6.
[163] Exhibit M2, p. 69. Concentric's historical MRP for Canadian markets is 5.68% and its historical U.S. MRP is 7.17%.
[164] Exhibit N-M4-0-SEC-82, p. 4.
[165] Exhibit M2, p. 9; and Undertaking J4.8.

Concentric's model is premised on the relationship between historical bond yields and authorized ROEs in the U.S. and Canada.[166] CCC has a number of concerns with Concentric's Risk Premium estimation approach.

First, it relies heavily on U.S. authorized returns. As noted previously, U.S. utilities are not reasonable comparators for Canadian utilities. U.S. utilities have significantly higher business risk. This operates to bias the estimated ROE upwards. This can be seen by reviewing the estimated ROE resulting from Concentric's Risk Premium approach for the Canadian proxy group, which has an estimated ROE of 9.31% (relative to 9.83% for the North American electric proxy group).[167] CCC does not accept the Canadian proxy group estimated ROE from the risk premium model, as it does not believe that using authorized ROEs to establish the base ROE is appropriate for the reasons that follow, but it does illustrate this fact.

Second, the U.S. authorized ROEs include those applicable to vertically integrated utilities. As noted previously, vertically integrated utilities have more risk than Ontario's distributors and transmitters that do not own any regulated generation assets. This is operating to upwardly bias the resulting recommended ROE by 28 basis points for the North American electric proxy group.[168]

Third, the authorized ROEs are not always established based on market data. Many of the authorized ROEs are based on settlements that would have involved compromises on other matters.[169] In addition, as discussed at the oral hearing, some of the U.S. authorized ROEs have been influenced by policy decisions by the regulator.[170]

Finally, the Risk Premium approach applied by Concentric does not directly measure the risks that are currently faced by Ontario's electricity distributors and transmitters. When asked whether its model measures the current risk for Ontario's utilities, Concentric stated:

> The current risk, umm, no, I would say it's a lagging indicator of risk. I guess, I would say that's probably a weakness of some of the models is that they don't do as good of a job as I would like of projecting forward risk, but that's a difficult thing to do.[171]

---

[166] Exhibit M2, pp. 74-75.
[167] Undertaking J4.8.
[168] Undertaking J3.2, Attachment 1.
[169] Oral Hearing Transcripts, pp. 34-35.
[170] Oral Hearing Transcripts, pp. 176-180.
[171] Oral Hearing Transcripts, Volume 4, p. 35.

In no way does the Risk Premium approach even consider the risks faced by Ontario's distributors. That is simply not part of the equation. CCC submits that this is a fundamental problem with Concentric's Risk Premium model.

For all of the above reasons, CCC submits that the recommendations resulting from all of Concentric's models (i.e., DCF, CAPM and Risk Premium) should be disregarded by the OEB and not reflected in the base ROE established in the current proceeding.

Nexus' Estimation of the Base ROE

Nexus arrives at its base ROE estimation of 11.08% by applying a weighted average to the results of its DCF, CAPM and Risk Premium approaches (and includes a transaction cost adder of 0.5%).[172] Nexus proposed that its base ROE be applied to electricity distributors only.[173]

Proxy Group

Nexus' proxy group is used directly as part of its DCF and CAPM estimations of the base ROE. Nexus created a single proxy group of 43 companies with 88% of the proxy group comprised of U.S. firms.

CCC submits that all of the problems that it referenced in its discussion of Concentric's proxy group are present in Nexus' proxy group. Specifically, Nexus' proxy group includes: (a) U.S. holding companies; (b) U.S. vertically integrated utilities; (c) holding companies with significant unregulated businesses; (d) companies that have higher regulatory risk than Ontario; and (e) the Canadian proxy companies include Emera Inc. and Fortis Inc. (which are not comparable to Ontario's distributors).

In fact, Nexus' proxy group is even less comparable to Ontario's electricity distributors and transmitters than Concentric's proxy group. While we do not agree with Concentric's proxy group for the reasons discussed previously, if you had applied Concentric's screening criteria to Nexus' proxy group only 18 of Nexus' 43 peer companies would have remained. The other 25 companies would have been removed for reasons including, but not limited to, low credit ratings, too little income derived from regulated electric activities, and merger

[172] Exhibit M3, p. 74. Nexus applies a weight of 38% to its DCF estimate, 49% to its CAPM estimate and 13% to its Risk Premium estimate.
[173] Exhibit M3-12-SEC-78.

and acquisition activity.[174] Nexus, itself, acknowledged that its proxy group includes several companies that may not be entirely comparable to Ontario distributors (and potentially should have been excluded).[175]

In addition, Nexus appears to know very little about the regulatory mechanisms applicable to the operating companies in its peer group. In response to a question that sought information about the regulatory mechanisms applicable to the peer companies, Nexus responded that preparing a response would take too much time and it may not even have the necessary data to respond.[176] However, CCC notes that there is some overlap between Nexus' and Concentric's proxy groups[177] and as previously established the peer companies in Concentric's proxy group, on average, have less favourable regulatory mechanisms relative to Ontario.

For the same reasons as Concentric, CCC submits that Nexus' proxy group is not relevant to the estimation of the base ROE for Ontario's distributors and transmitters as the peers have significantly higher risk. Therefore, the results from its DCF and CAPM estimates should be disregarded on the basis of the proxy group alone. There are also problems with the model specifications that further call into question the base ROE recommendation, which are discussed below.

DCF Approach

Nexus' single-stage DCF analysis relies on its selected proxy group and results in a base ROE of 11.42% (including transaction costs).[178] Similar to Concentric, Nexus' peer group is almost entirely comprised of peers that are riskier than Ontario distributors and transmitters and therefore the DCF model output will be upwardly biased. Also similar to Concentric's DCF analysis, the growth estimates are based on analyst growth forecasts, which are known to be overly optimistic.

[174] Undertaking J4.3, Attachment 1.
[175] Oral Hearing Transcripts, Volume 5, pp. 15-24. SEC and Nexus discussed amongst other companies: (a) Alaska Power and Telephone company, which derives approximately 50% of its revenues from a telecommunications business; Otter Tail Corporation, which derives the majority of its income from a manufacturing business; TransAlta that holds no distribution businesses; and Pacific Gas and Electric, which had a recent bankruptcy filing.
[176] Exhibit M3-CCC-5.
[177] Undertaking J4.3, Attachment 1 shows that 18 companies overlap.
[178] Exhibit M3, p. 74. The base ROE from the DCF is 10.92% and Nexus adds 0.5% transaction costs in the final recommended ROE resulting from its weighted average of the three estimates.

In addition, Nexus uses a single-stage DCF model (instead of a multi-stage DCF), which implies that its selected growth rate will exist in perpetuity. Nexus' growth rate is even higher than the growth rate used by Concentric (and is in not moderated by the use of a multi-stage DCF model).[179] Therefore, Nexus' DCF model also assumes that utilities' earnings and dividends will grow at rates above nominal GDP growth (and those growth rates will persist forever). Dr. Cleary stated that this is not a realistic assumption for mature, stable operating utilities.[180] CCC agrees with Dr. Cleary's concerns regarding the specifications of Nexus' DCF model and, similar to Concentric, the result is that Nexus' DCF-derived ROE is significantly overstated for application to Ontario distributors and transmitters.

CAPM Approach

Nexus' CAPM approach results in a base ROE of 10.69% (including transaction costs).[181] CCC is concerned with many of the decisions that Nexus made with respect to its CAPM model specifications.

First, Nexus' risk-free rate is entirely based on 30-year U.S. treasury bonds with a forecast yield of 4.06%. As discussed with respect to Concentric's use of a combination of Canadian and U.S. government bond yields, this is not appropriate. CCC submits that the risk-free rate for Canadian investors is properly reflected by the 30-year Government of Canada bond yield for the reasons discussed previously. Nexus' risk-free rate is even less applicable than Concentric's risk-free rate (as it does not reflect Canadian government bond yields at all).

Second, similar to Concentric, Nexus' peer group is the basis for the adjusted betas used in its CAPM model. Its proxy group has an average adjusted beta of 0.69, which is directly used in the calculation of the CAPM-derived ROE estimation.[182] CCC submits that, as the companies in Concentric's proxy group are riskier than Ontario's distributors and transmitters for all the reasons previously discussed, the average beta estimate used in its CAPM model will be overstated. Similarly, the use of adjusted betas is also inappropriate, and further upwardly biases the betas, for the reasons discussed in the submission regarding Concentric's CAPM model.

[179] Nexus Economics Presentation Day Materials, p. 27. Nexus's growth rate is 7.11% and Concentric's growth rate is 5.98% for the first five years (and it starts declining after that).
[180] Exhibit N-M4-0-SEC-82, pp. 2-3.
[181] Exhibit M3, p. 74. The base ROE from the CAPM is 10.19% and Nexus adds 0.5% transaction costs in the final recommended ROE resulting from its weighted average of its three estimates.
[182] Exhibit M2, p. 66.

Finally, Nexus uses forward-looking U.S. data to calculate the MRP used in its CAPM-derived ROE estimation. Nexus' growth rate, which underpins its calculations, is 11.49% and the resulting expected market return is 12.89%.[183] As noted by Dr. Cleary, this is an unrealistic estimate of expected growth and market returns. Dr. Cleary stated that Nexus' growth rates imply that expected profits and dividends of North American utilities will grow (to infinity) at rates that are almost triple forecasts of expected nominal GDP growth rates. He also stated that such a high predicted expected market return of 12.89% is completely inconsistent with the long-term average expectations of market professionals.[184] CCC notes that even Concentric, while using U.S. data in its MRP estimate, relied on historical data as it acknowledged the "substantial differences between the historical and forward market risk premiums."[185]

Risk Premium

Nexus' Risk Premium approach results in a recommended base ROE of 11.59% (including transaction costs).[186] Nexus' model is premised on the relationship between historical bond yields and authorized ROEs in the U.S.[187] CCC has similar concerns with Nexus' Risk Premium estimation approach as it has with Concentric's:

- It relies on only U.S. authorized returns (there are no Canadian authorized ROEs considered)
- The U.S. authorized returns include vertically integrated companies
- The authorized returns are not always established based on market data
- It does not directly measure the risk of Ontario's distributors and transmitters.

For all of the above reasons, CCC submits that the recommendations resulting from all of Nexus' models (i.e., DCF, CAPM and Risk Premium) should also be disregarded by the OEB and not reflected in the base ROE established in the current proceeding.

[183] Exhibit M3, p. 63.
[184] Exhibit N-M4-0-SEC-83.
[185] Exhibit M2, p. 69.
[186] Exhibit M3, p. 74.
[187] Exhibit M3, pp. 72-73.

<u>LEI's Estimation of the Base ROE</u>

LEI's recommendation for the base ROE is 8.95% (or 8.88% as updated), which is based on its CAPM approach (and does not include a transaction cost adder).[188] LEI recommended that its base ROE be applied to all rate-regulated utilities in Ontario.

With respect to LEI's proposal to establish a single ROE for all rate-regulated utilities in Ontario, CCC submits that this is not appropriate as there is sufficient difference between the various sectors (i.e., electricity generation, electricity distribution and transmission, and generation) to warrant the setting of individual ROEs by sector (and the equity thickness should be established in coordination with, and thus at the same time as, the ROE). CCC does not believe that LEI's proposal to use a rate base-weighted average of sector betas to determine a uniform beta that underpins the CAPM-derived ROE[189] will result in an appropriate ROE for each sector.

Proxy Group

LEI's proxy group is used directly as part of its CAPM-derived estimation of the base ROE. LEI developed three proxy groups (generation, wires (i.e., distribution and transmission) and natural gas distribution).[190] In total, LEI includes 28 companies in its proxy group for the CAPM estimate with 71% being U.S. firms. When considering only the electricity distribution and transmission peer group, 89% are U.S. firms.[191]

As discussed previously, CCC submits that U.S. utilities are not reasonable comparators for Canadian utilities. U.S. utilities have significantly higher business risk due to their holding company structure (and related holdings) and due to the nature of their operations. Therefore, LEI's heavy reliance on U.S. firms in its proxy groups is not appropriate.

Given that LEI is seeking to establish a base ROE for all rate-regulated Ontario utilities, there is logic to including a generation proxy group. However, its electric distribution and transmission proxy group also includes utilities that own generation assets (i.e., vertically integrated electric companies). For example, Ameren Corporation has a large generation fleet, which includes coal-fired generation as part of its portfolio of generation assets.[192] In

[188] Exhibit J2.2.
[189] Exhibit M1, p. 119.
[190] Exhibit M1, p. 119.
[191] Exhibit M1, p. 118.
[192] Exhibit K2.6, p.186.

addition, Edison International and First Energy Corporation are vertically integrated utilities as referenced in SEC's submission.[193] Therefore, LEI's proxy group, overall, is biased towards utilities that own generation assets and, as noted previously, vertically integrated electric companies are not comparable to Ontario's distributors and transmitters.

There are also problems with LEI's natural gas peer group. As our focus is on electricity distributors and transmitters, CCC mentions, only briefly, that AltaGas Limited (62% of its income is derived from unregulated businesses) and Enbridge Gas Inc. (87% of its income is derived from unregulated businesses) [194] are not reasonable comparators to Ontario's natural gas distributors.

CCC submits that LEI's proxy group has similar problems to those of Concentric and Nexus. The heavy reliance on U.S. firms, the inclusion of a generation proxy group, and the inclusion of vertically integrated companies in its "wires" proxy group makes it unsuitable for the establishment of the base ROE for Ontario's electricity distributors and transmitters. There are also problems with the CAPM model specifications that further call into question the base ROE recommendation, which are discussed below.

CAPM Approach

CCC submits that LEI's risk-free rate, which is based on a 30-year Government of Canada bond yield, is appropriate. LEI uses a forecast approach to determine the risk-free rate whereby the upcoming year's Government of Canada bond yield is estimated based on an average from multiple sources.[195] CCC prefers a methodology that uses the current 30-year government bond yield (at the time that the ROE is being established) relative to LEI's forecast approach as is discussed later in the submission.

As LEI's proxy group is the basis for the beta estimate, and that proxy group includes companies that are riskier than Ontario's electricity distributors and transmitters, the average beta estimate used in its CAPM model will be overstated. LEI does not use adjusted betas, which CCC submits is appropriate. However, its average raw beta is 0.69[196], which is the same as the adjusted beta that Nexus uses in its CAPM model.[197] This,

[193] EB-2024-0063, SEC Submission, November 7, 2024.
[194] Exhibit N-M2-CCC-4, Attachment 1.
[195] Undertaking J2.2.
[196] Exhibit M1, p. 119. We note that the electricity transmission and distribution beta is 0.67.
[197] Nexus Presentation Day Materials, p. 19.

again, compares to the raw beta for Hydro One of 0.54[198] and illustrates that a beta derived using U.S. peers is biased upwards.

Finally, LEI's estimated MRP is entirely based on historical U.S. data. As shown in the table below, which is reproduced from LEI's base ROE update, LEI takes an average of the MRP resulting from three time periods (which overlap).[199]

Figure 8. LEI Report – Figure 41 (with risk-free rate updated as of September 30, 2024)

MRP variables	Risk-free rate (R_f)	Beta	MRP	ERP (Beta * MRP)	CAPM ROE (R_f + ERP)
1928-2023 S&P 500 total returns - US 10-year treasury bond yields	3.127%	0.69	6.54%	4.53%	7.65%
1984-2023 S&P 500 total returns - US 30-year treasury bond yields			7.12%	4.92%	8.05%
1994-2023 S&P 500 total returns - US 30-year treasury bond yields			7.28%	5.03%	8.16%
2004-2023 S&P 500 total returns - US 30-year treasury bond yields			7.52%	5.20%	8.32%
2014-2023 S&P 500 total returns - US 30-year treasury bond yields			10.16%	7.03%	10.15%
2004-2023 S&P/TSX total returns - 30-year GoC bond yields			2.81%	1.94%	5.07%
LEI recommendation	3.127%	0.69	8.32%	5.75%	8.88%

LEI stated that it believes that CAPM ROE based on Canadian market data does not reflect investors' expected equity returns.[200] Therefore, it disregarded this data point.

As discussed previously, CCC submits that Canadian investors have a home bias. Therefore, excluding Canadian market data from the estimation of the MRP is not appropriate. CCC further notes that if Canadian data had been included in the CAPM ROE based on weights of 75/25 (Canada and US), 50/50 (Canada/USA), 25/75 (Canada/US), the resulting ROE would be 6.13%, 7.10%, and 8.07%, respectively.[201] LEI's decision to exclude Canadian market data operates to significantly upwardly bias its CAPM-derived ROE estimate.

In addition, CCC notes that LEI's MRP estimate averages the S&P Global 500 total returns minus U.S. 30-year treasury bond yields for the periods: (a) 1994-2023; (b) 2004-2023; and (c) 2014-2023. This average provides more weighting to recent 2014-2023 data (as it is in all three time periods). The 2014-2023 market returns are significantly higher than the other

[198] Exhibit N-M2-CCC-4, Attachment 1.
[199] Undertaking J2.2.
[200] Exhibit M1, p. 120.
[201] Exhibit N-M1-10-SEC-18. These figures are based on the as-filed base ROE recommendation of 8.95%.

time periods. As noted by Dr. Cleary, the U.S. stock market has been "producing abnormally high real returns relative to its longer term history, and relative to global equity returns in other markets."[202] CCC submits that LEI's decision to weight its U.S. market returns to the most recent time period also operates to significantly upwardly bias its CAPM-derived ROE estimate.

For all of the above reasons, CCC submits that LEI's recommendation for the base ROE should also be disregarded by the OEB and not reflected in the base ROE established in the current proceeding.

<u>Dr. Cleary's Estimation of the Base ROE</u>

Dr. Cleary calculates his base ROE estimate of 7.05% (or 6.95% as updated) (which includes a transaction cost adder of 0.5%) by averaging the results of his DCF, CAPM and Bond Yield plus Risk Premium (BYPRP) approaches.[203] Dr. Cleary proposed that his base ROE be applied to all rate-regulated utilities. For the reasons previously discussed, CCC submits that the ROE established in this proceeding should apply to only electricity distributors and transmitters.

Proxy Group

Dr. Cleary's proxy group is comprised of only Canadian firms and the proxy group is used only in his DCF approach to estimating the base ROE.[204] Dr. Cleary's proxy group includes the same five companies that the Alberta Utilities Commissions (AUC) determined were reasonably comparable Canadian utilities as follows: Algonquin Power & Utilities Corp., Canadian Utilities Limited, Emera Inc., Fortis Inc., and Hydro One.[205]

Dr. Cleary's proxy group has the benefit relative to the other experts that it includes only Canadian companies, which avoids the comparison of Ontario utilities to U.S. firms that have higher risk in the derivation of an appropriate base ROE. However, CCC has concerns with a number of the firms that are included in Dr. Cleary's proxy group. As discussed previously with respect to Concentric's proxy group, Emera Inc. and Fortis Inc. own significant generation assets[206] and Canadian Utilities Limited derives 8% of its income

[202] Exhibit M4, p. 83.
[203] Exhibit M4, pp. 9-10; and Undertaking J5.3.
[204] Exhibit M4, p. 93; and Exhibit N-M4-CCC-7.
[205] Exhibit N-M4-CCC-7.
[206] Undertaking J3.2, Attachment 1.

from unregulated operations.[207] CCC notes that Algonquin Power & Utilities Corp. has a BBB rating from S&P Global[208], derives 15% of its revenue from unregulated operations and has a significant generation business.[209] Therefore, the only company in the peer group that is comparable to Ontario distributors and transmitters is Hydro One.

Dr. Clearly acknowledges that "it is difficult to find "typical" or representative Canadian regulated publicly traded utilities."[210] CCC agrees and would elaborate that finding a reasonable proxy group to use directly in determining the base ROE for Ontario's rate-regulated distributors and transmitters is nearly impossible.

DCF Approach

Dr. Cleary's DCF analysis relies on his selected proxy group and results in a base ROE of 7.4% (including a 0.5% transaction cost adder).[211] As the peer group is almost entirely comprised of peers that are riskier than Ontario distributors and transmitters and the financial information from these peers is an input to the DCF model, the output of that model is likely to be overstated. Dr. Cleary, himself, acknowledges that the result of his DCF analysis "seems slightly high for below-average risk utilities relative to overall expected market returns."[212]

Other than the concerns with the proxy group, the use of which is necessary to operationalize the DCF model, CCC submits that Dr. Cleary's model specifications are much preferable to the other experts. For example, Dr. Cleary determines a sustainable growth rate for use in his DCF approach. Applying a sustainable growth rate in the DCF is appropriate as utility companies distribute a significant amount of their earnings as dividends each year and have relatively stable ROE figures. This method also avoids using analyst growth estimates, which, as discussed previously, are biased upwards.

As another example, Dr. Cleary applies multiple variations of the DCF approach and averages the results from those tests in an effort to better estimate the base ROE. More specifically, Dr. Cleary uses both single-stage DCF and multi-stage DCF (through the H-Model) to determine the DCF-derived base ROE.[213]

[207] Exhibit N-M2-CCC-4.
[208] Exhibit N-M4-CCC-7(d).
[209] Exhibit N-M4-10-OEA-11, part (c) and Attachment 1, p. 8.
[210] Exhibit M4, p. 101.
[211] Exhibit M4, p. 106.
[212] Exhibit M4, p. 106.
[213] Exhibit M4, pp. 105-106.

Overall, CCC submits that Dr. Cleary's DCF analysis is superior to that of Concentric and Nexus as he does not include U.S. firms, his estimate for growth is more realistic and the use of multiple variations of the DCF model helps to moderate the results. However, his DCF approach, similar to the DCF approaches of Concentric and Nexus, also relies on a proxy group that CCC views as being higher risk than Ontario's electricity distributors and transmitters.

As will be discussed in section 3.4 of the submission, CCC submits that the OEB should not use a proxy group-based approach to determining the base ROE as there are so few reasonable comparators to Ontario electricity distributors and transmitters to build such a group.

Dr. Cleary provides two approaches for determining the base ROE that do not rely on proxy groups directly in the calculations. Other than these two approaches, the only other methods that do not rely directly on a proxy group are Concentric's and Nexus's Risk Premium approaches that instead use authorized U.S. ROEs in the calculation, which are arguably even worse than the other approaches.

As discussed below, Dr. Cleary's CAPM and BYPRP approaches do not rely on proxy group data directly in the determination of an appropriate ROE.

CAPM Approach

Dr. Cleary's CAPM approach results in a base ROE of 6.05% (or 5.87% as updated) (including a 50 basis point transaction cost adder).[214] CCC submits that Dr. Cleary's CAPM result is the most reflective of the risk profile of Ontario's electricity distributors and transmitters as the model specifications are the most reasonable.

First, CCC submits that Dr. Cleary's risk-free rate, which is based on a 30-year Government of Canada bond yield, is appropriate. Instead of LEI's consensus forecast approach to determine the risk-free rate, Dr. Cleary uses the actual long-term Government of Canada bond yield at a point in time (June 5, 2024 in his report[215] and September 27, 2024 in his update[216]) (current bond yield). CCC supports this approach as we agree with Dr. Cleary's analysis that using forecast yields has led to an upward bias relative to the actual yields

[214] Undertaking J5.3.
[215] Exhibit M4, p. 71.
[216] Undertaking J5.3.

that occur. As shown in Dr. Cleary's evidence, forecasts of 30-year bond yields (using a similar methodology as suggested by LEI in this proceeding) have been about 0.4% higher than the actual bond yield that occurred in the subsequent year. Dr. Cleary further shows that if the current bond yield (at the end of September) was used for the upcoming year, the variance between the current bond yield and the actual bond yield is nearly zero.[217] The use of the forecast bond yields has historically led to variances between forecast yields and actual yields that can be avoided by simply using current bond yields in the forecast of the risk-free rate.

Second, CCC submits that Dr. Cleary's approach to determining the average beta is the most reflective of the risks faced by Ontario's rate-regulated utilities. Dr. Cleary relies on a long-term average of Canadian utility unadjusted (or raw) betas. Dr. Cleary uses historical data, which is based on a few long time series and different samples of Canadian utility betas[218], as the starting point for his analysis. The historical data provides a long-term average beta estimate of 0.35 (with beta estimates never exceeding 0.72).[219] Dr. Cleary then reviews current unadjusted betas (on December 31, 2023) and more recent betas over the 2016-2023 period, which he averages to derive a more recent average beta of 0.60. Dr. Cleary then considers the long-term historical beta average of 0.35 and the more recent beta average of 0.6 to establish his estimated beta for low-risk Ontario rate-regulated utilities of 0.45.[220]

CCC submits that this is the appropriate way to go about estimating beta for Ontario's utilities. Dr. Cleary does not simply accept the outputs of a proxy group as the right answer. He looks at multiple perspectives – different samples, different time periods, different averages (weekly or monthly betas) to derive an appropriate average beta. This methodology avoids the need to directly use current betas derived from a proxy group that includes U.S. firms in the determination of a CAPM-derived base ROE. It also avoids the problem that beta estimates for individual companies can change dramatically over time. Dr. Cleary noted that if he had used December 31, 2022 data (instead of December 31, 2023 data) to determine the more recent average of betas, the resulting beta would be 0.355 (which compares to the 0.60 average beta using December 31, 2023 data).[221] Dr. Cleary's approach reflects the only derivation of beta in this proceeding that recognizes the

---

[217] Exhibit M4, Appendix A.
[218] Dr. Cleary uses both weekly and monthly averages of betas based on: (a) 1988-2016 data for a sample of Major Canadian Utility Holding Companies; (b) 1992-2016 data based on the Utility Sub-Index for the S&P TSX; and (c) 1996-2017 data based on a Canadian Utility Proxy group.
[219] Exhibit M4, Appendix C.
[220] Exhibit M4, p. 92.
[221] Exhibit M4, p. 92.

shorter-term volatility in beta that can lead to poor beta forecasting (and thus an inaccurate CAPM-derived ROE).

CCC also submits that it is the only beta result that incorporates common sense. A beta of 1.0 reflects the market average. Obviously, monopoly service providers that are rate-regulated have significantly lower risk than the average company traded on the stock exchange. You are comparing regulated utilities that have revenue stability[222] because of rate-regulation to companies that are operating in competitive markets that have no such protections. Moving beyond a general comparison of rate-regulated utilities to the average company traded on the market, as discussed previously, the OEB's regulatory framework applicable to Ontario's electricity distributors and transmitters is very favourable to utilities (e.g., cost recovery mechanisms, reduced regulatory lag, proactive regulation, etc.). So not only are Ontario's electricity distributors and transmitters generally less risky than the market average, CCC submits that they are less risky than the utilities that the other experts compare them against. For these reasons, a beta of 0.45 is reasonable, and perhaps even a bit high for electricity distributors and transmitters given that the beta of 0.45 is relevant for all Ontario utilities.

Finally, similar to the determination of the beta, Dr. Cleary looks at multiple data sets of Canadian market returns (both historical and forecast) from various sources to derive an appropriate MRP. He also considers finance literature and the practices of finance professionals.

More specifically, Dr. Cleary's analysis highlights that the historical Canadian market return (based on three historical data sets[223]) is approximately 6.5% on average in real terms (and 8.5% when adjusted to nominal terms). The forecast Canadian market return (based on a number of financial professional estimates[224]) is 6.1% on average in nominal terms.[225] Taking into account both the historical and forecast market returns, Dr. Cleary determines that a reasonable estimate of the expected Canadian stock market return is 7.5%.[226]

Dr. Cleary also looks at the average Canadian market returns relative to the long Government of Canada bond yields over a number of different historical periods and points

[222] Exhibit M1, p. 75.
[223] These data sets are 1938-2023, 1900-2015 and 1915-2014.
[224] With respect to Canadian data, Dr. Cleary uses reports from FP Canada, Frankling and Templeton Investments, and BlackRock.
[225] Exhibit M4, pp. 82-83.
[226] Exhibit M4, pp. 83. Dr. Cleary notes that a 7.5% forecast for the Canadian market return is within the range of 6%-9% that is aligned with both historical and forecasts by investment professionals.

in time. This view of MRP shows that the difference between Canadian bond yields over the 1938-2023 period was 4.97% (with other time series showing a range from 4.2% to 5.2%).[227]

Dr. Cleary considers all these data points and the common practice of finance professionals, which use a range of 4%-6% when determining MRP, to establish the MRP of 5%. Dr. Cleary noted that his MRP estimate of 5% is: (a) equivalent to the 4.97% average difference between Canadian stock and government bond returns over the 1938-2023 period; (b) is slightly above the mid-point of 4.7% of the long-term arithmetic average Canadian MRP of 4.2% and the 5.2% forecast MRP documented in a recent study[228]; and (c) is consistent with the practice of financial professions to use an MRP of 5% when markets are close to normal (i.e., not experiencing above average uncertainty or above average optimism).[229]

Overall, Dr. Cleary takes a thoughtful approach to determining the risk-free rate, beta and MRP in his CAPM model. He considers multiple data points in each determination and ensures that the input is reasonable based on various considerations.

Bond Yield Plus Risk Premium

Dr. Cleary's BYPRP approach results in a recommended base ROE of 7.7% (or 7.6% as updated) (including a 0.5% transaction cost adder).[230] Dr. Cleary's Risk Premium approach is different than the approaches of Concentric and Nexus. Dr. Cleary's approach does not rely on authorized returns for other utilities in various jurisdictions. Instead, Dr. Cleary adds a risk premium of 2.5% to the Canadian A-rated utility long-term bond yield.

With respect to the utility long-term bond yield, Dr. Cleary, in the updated base ROE recommendation using the BYPRP approach, considered the current yield on long-term A-rated Canadian utility bonds of 4.51% (as of September 27, 2024). He also looked at the average yield on bonds outstanding for five Canadian operating utilities as of October 3, 2024, which was 4.70%.[231] In addition, he considered the bond yield, on the same date, for Hydro One, which was 4.61%. Based on those considerations, Dr. Cleary determined that a reasonable bond yield to use for Ontario's utilities is 4.60%.[232]

[227] Exhibit M4, pp. 84-85.
[228] Fernandez et al., Survey: Market Risk Premium and Risk-Free Rate used for 96 countries in 2024.
[229] Exhibit M4, p. 86.
[230] Undertaking J5.3.
[231] These utilities include Fortis Alberta Inc., Fortis BC Inc., Canadian Utilities Inc., Enbridge Gas Inc., and Hydro One Inc.
[232] Exhibit J5.3.

In determining the risk premium to add to the cost of debt, Dr. Cleary considered the typical range of risk premium adders of 2%-5% applied by financial professionals, with 3.5% being commonly used for average risk companies, and lower values applied for less risky companies. He determined that, in the context of the low risk of Ontario's rate regulated utilities, a 2.5% risk premium is appropriate (as rate-regulated utilities have below average risk relative to the market).[233]

Dr. Cleary provided evidence supporting the typical range of risk premium adders of 2%-5% applied by financial professionals. He stated that based on his own experience with using the BYPRP approach and also observing numerous estimates provided by analysts based on such approach, a risk premium in the range of 2% to 5% is added to a company's existing bond yields, with 3.5% being applied for average risk companies. Dr. Cleary stated that this is basic practice for finance professionals. Dr. Cleary noted that he has seen the 2% to 5% range used in countless analyst reports that he has directly reviewed over the years. He further references a number of corporate finance textbooks and readings used in the CFA and CPA programs that discuss the range of risk premiums to be used in the BYPRP model.[234] For example, in a corporate finance textbook, the authors note that "empirical work suggests the risk premium over the firm's own bond yield has generally ranged from 3 to 5 percentage points, with recent values close to 3%."[235] Considering the much lower risk of Ontario's electricity distributors and transmitters relative to the average risk of publicly traded companies in the market, CCC agrees with Dr. Cleary that it is appropriate to apply a risk premium of 2.5% for these firms.

Overall, CCC agrees with Dr. Cleary's specifications of the utility bond yield and risk premium applied in the BYPRP approach. Further, CCC submits that Dr. Cleary's BYPRP approach is logical as it allows for the establishment of the base ROE in a straight-forward manner that directly considers the deemed cost of utility long-term debt (as reflected by the market-determined utility bond yield) and the premium over the bond yield that investors require due to the higher risk of equity investments.

[233] Exhibit M4, pp. 107-108.
[234] Exhibit N-M4-EDA-5. The ranges provided in these various reports are 1%-3%, 3%-4% and 3%-5%.
[235] Corporate Finance: A Focused Approach, 3E, Michael Ehrhardt, Eugene Brigham, South-Western Cengage Learning, 2008, Chapter 9, Section 9.7, page 303.

Transaction Costs

Concentric, Nexus and Dr. Cleary recommended that a 50 basis point adder be reflected in their recommended base ROEs for transaction costs, which is also described as flotation costs or flexibility costs in the evidence.[236] LEI recommended that flotation costs should not be included in its recommended base ROE.[237] The OEB's current base ROE as established in the 2009 Cost of Capital proceeding includes an implicit 50 basis points adder for transaction costs.[238] CCC submits that regardless of the base ROE that the OEB determines to be appropriate in the current proceeding, there should be no transaction costs included.

As discussed by LEI, equity issuances do not occur with predictable regularity, which makes the associated transaction costs more suitable to recover if and when the utility incurs those expenses.[239] CCC notes that there have been no actual equity investments by the large electricity distributors and transmitters since 2019.[240] This supports LEI's statement that there is no regularity to equity issuances.

LEI further stated that a 50 basis point adder will likely lead to overcompensation of Ontario's utilities, given its application to all deemed equity (as opposed to only new issuances). LEI analyzed information from Enbridge Gas's treasury team, which similarly implies that a 50 basis point adder for transaction costs is resulting in overcompensation of utilities.[241] Concentric also appears to acknowledge that a 50 basis point adder may be too high. Concentric stated that based on its "prior analysis of flotation costs, the empirical study cited by Dr. Morin, and the recent Enbridge analysis, our view is that flotation costs for utilities are within a range from 2% to 10%, with an average of around 5%. This can be translated into ROE by adjusting the dividend yield in the DCF model. Using this method, if flotation costs are equal to 5% of the gross proceeds of the equity issuance, then the adjustment to ROE would be approximately 25 basis points for companies like those in Concentric's North American combined proxy group."[242]

---

[236] Exhibit M2, p. 9 (Concentric notes that transaction costs are included in its DCF and CAPM results); Exhibit M3, p. 5; and Exhibit M4, p. 38.
[237] Exhibit M1, p. 122.
[238] Ontario Energy Board, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, p. 37.
[239] Exhibit M1, p. 38.
[240] Exhibit N-M2-10-SEC-41(c).
[241] LEI Presentation Day Materials, p. 8.
[242] Exhibit N-M2-10-Staff-16.

CCC also notes that the vast majority of Ontario's electricity distributors and transmitters are municipally, or provincially, owned. CCC submits that these companies will not incur actual transaction costs anywhere near the level of publicly traded companies that issues shares into the market. The costs that municipally, or provincially, owned utilities will incur with respect to equity issuances are largely related to legal and consultant fees. However, the significant underwriting fees (as would be incurred by a publicly-traded company) would be avoided.

For these reasons, CCC submits that a generic transaction cost adder included in the base ROE is inappropriate. While transaction costs are legitimate costs that are appropriately recoverable by utilities, given the rarity of actual equity issuances and the likelihood that a generic transaction cost adder will overcompensate most utilities (as most are not publicly traded companies), a generic adder is not the correct mechanism for cost recovery.

Instead, CCC submits that the OEB should establish a generic deferral account that will come into effect at the time of each utilities next rebasing, which will allow the utilities to record actual transaction costs associated with equity issuances. There is no need to forecast these costs at the time of the rebasing, the deferral account should operate to record the actual transaction costs for disposition at the time of the next rebasing after the amount is recorded (based on there being no transaction costs included in rates). This will ensure that only actual equity issuance-related transaction costs are recovered by utilities (as opposed to the current practice that is clearly overcompensating utilities for equity issuances that rarely actually occur).

As noted by LEI, the review of the balances in this new generic deferral account does not need to be burdensome. More specifically, the utility would simply provide evidence regarding the actual transaction cost (i.e., a breakdown of the various costs incurred – legal fees, consultant fees, etc.) and show that those costs are reasonable.[243] As with every new regulatory mechanism (and associated cost being reviewed), the OEB will gain experience, and the review will become more mechanistic over time.

3.4. CCC's Proposed Base Return on Equity

For the reasons that follow, CCC submits that the base ROE for electricity distributors and transmitters should be set at 7.1%, which aligns with Dr. Cleary's BYPRP estimate (removing the transaction cost adder).[244] CCC submits that transaction costs should not be

[243] Oral Hearing Transcripts, pp. 78-79.
[244] Undertaking J5.3, p. 3.

included in the base ROE for the reasons previously discussed. Further, CCC submits that the equity thickness for electricity distributors and transmitters should be maintained at 40% assuming the ROE is set at 7.1%[245] and the OEB does not continue its approach of establishing a single ROE for all rate-regulated utilities.

As discussed previously, the base ROE established in 2009 was higher than necessary to meet the fair return standard. The changes to regulatory policy and the OEB's proactive approach to regulation has de-risked Ontario's electricity distributors and transmitters over the past 15 years. Due to the OEB's favourable regulatory framework applicable to Ontario's distributors and transmitters, energy transition, climate and cyber security risks are not negatively impacting the risk profile of these companies.

The recommendations of Concentric, Nexus and LEI all operate to increase the implied equity risk premium (i.e., the recommended base ROE minus the risk-free rate) relative to the implied equity risk premium approved in 2009 (as shown in the table below). Therefore, the results of their recommendations are not reasonable and if applied by the OEB in the determination of the 2025 base ROE, will result in the continued payment of economic rent by ratepayers.

[245] It is important to note that there is a direct connection between the ROE/equity thickness and the allowed return. Changes to either the ROE or equity thickness have an impact on allowed aggregate returns (and the overall satisfaction of the fair return standard).

Summary of the Implied Equity Risk Premiums from the Updated Base ROE Recommendations in the Expert Reports

	Concentric	Nexus	LEI	Dr. Cleary	2009 OEB Cost of Capital Report
Post-Hearing Updated Recommended Base ROE	10%	11.08%	8.88%	6.95%	
Implied Equity Risk Premium (ERP) of Updated Recommended Base ROE (using LEI's Risk-Free Rate)[246]	6.87%[247]	7.95%[248]	5.75%	3.82%	5.50%[249]

CCC submits that the OEB should fundamentally change its approach to establishing the base ROE. More specifically, the OEB should transition away from a proxy group-based approach. As discussed previously, there are so few truly comparable companies that are publicly traded (which is necessary in order to derive financial information to operationalize certain estimation approaches as applied by Concentric (DCF and CAPM), Nexus (DCF and CAPM), LEI (CAPM) and Dr. Cleary (DCF)), which makes the use of proxy groups highly problematic.

Dr. Cleary provided two approaches that allow the OEB to establish a base ROE without the need to directly input financial information from individual companies included in a given proxy group (and also avoids using authorized returns from other jurisdictions, which is inappropriate for the reasons discussed previously).

The first approach is his version of the CAPM, which uses long-term historical average betas and a consideration of more current raw betas for Canadian utilities[250] (as opposed to betas derived from individual companies in the experts' proxy groups).

The second approach is the Bond Yield Plus Risk Premium approach, which adds a risk premium to the current Canadian A-rated utility long-term bond yield. The BYPRP approach

---

[246] Ontario Energy Board, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, p. 26. For comparison purposes, similar to the manner the figures were shown in the 2009 Cost of Capital Report, we have applied the 3.13% risk-free rate set out by LEI in Undertaking J2.2 to determine the implied ERP from the expert's recommendations.
[247] Exhibit M2, p. 100. Concentric views the implied ERP from its base ROE recommendation to be 6.19% as it uses an average U.S. and Canada bond estimate of 3.8% (i.e., 10%-3.8% = approximately 6.2%).
[248] Exhibit M3, p. 39. The implied ERP from Nexus' base ROE recommendation, using its risk-free rate based on a 30-year U.S. Treasury bond yield of 4.06%, would be 7.02% (i.e., 11.08%-4.06% = 7.02%).
[249] Ontario Energy Board, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, p. 37. The 5.5% (or 550 basis points) reflects the implied ERP that was added to the risk-free rate in 2009 of 4.25% to establish the 2009 base ROE of 9.75%.
[250] Exhibit M4, pp. 92.

does not directly input any individual company's financial information in the model. Though, Dr. Cleary does look at some individual Canadian operating companies' debt costs as a reasonableness check on the overall Canadian A-rated utility bond index yield.[251]

CCC believes that both Dr. Cleary's version of the CAPM approach and the BYPRP approach are reasonable for determining the base ROE for Ontario's electricity distributors and transmitters. CCC prefers the BYPRP approach, which establishes the base ROE at 7.1% (excluding the transaction cost adder). CCC notes that Dr. Cleary's recommended that his proposed base ROE be applied to all Ontario utilities. This suggests that the ROE might be a little high for the Ontario electricity distributors and transmitters due to their lower risk than Enbridge Gas (and different risk than OPG). However, for the following reasons, CCC believes that the 7.1% base ROE derived from the BYPRP is reasonable and, overall, will meet the fair return standard for these companies (and will not result in the payment of economic rent).

- The BYPRP approach is simple and straightforward and directly addresses the relationship between the bond and stock markets.
- The BYPRP approach uses directly observable market-determined long-term utility bond yields as the starting point for the estimation of the base ROE.
- The utility bond yield used in the BYPRP is essentially the same as reflected in the annual ROE adjustment formula, which allows for the entire ROE setting exercise over time to be internally consistent.
- The BYPRP approach allows for a holistic consideration of the risk of Ontario electricity distributors and transmitters in setting the base ROE and is easily adjustable by the OEB to reflect changes in the risk faced by Ontario's electricity distributors and transmitters over time (as needed).
- The result of the BYPRP approach (i.e., a base ROE of 7.1% excluding transaction costs) is properly below the expectation of the average Canadian market return (7.5%).
- The BYPRP approach is no more subjective than any of the other approaches put forward by the experts in this proceeding.
- The BYPRP approach results in a base ROE for Ontario's electricity distributors and transmitters not a proxy group of largely U.S. holding companies.

First, CCC submits that the BYPRP approach is the most straightforward approach that was proposed by any of the experts in the current proceeding. It follows the simple logic that a

[251] Undertaking J5.3.

premium over the deemed cost of utility long-term debt (as reflected by the A-rated Canadian utility bond index) is necessary to reflect the higher risk of equity investments relative to bond investments.

Second, the basis for the utility bond yield in the BYPRP approach is a market-determined figure based on the A-rated Canadian utility bond index. This is a valid, and conservative, proxy for the cost of debt for Ontario's electricity distributors and transmitters as these companies have an average S&P Global credit rating of A (for the Ontario utilities where information is available).[252] CCC notes that Dr. Cleary's updated bond yield applied in his BYPRP approach of 4.6% is slightly higher (9 basis points) than the A-rated utility bond index of 4.51% as he considered other data points in finalizing the cost of debt in the BYPRP.[253] CCC submits that this results in a conservative estimate of the cost of debt for Ontario's electricity distributors and transmitters (which have an average credit rating of A from S&P Global). While CCC believes that 4.6% is a reasonable estimate of the cost of debt for Ontario's utilities and accepts this estimate for the purposes of establishing the base ROE, the OEB could consider using 4.51% as the cost of debt as it has the benefit of matching exactly the debt costs used in the annual ROE adjustment formula (and in the determination of the DLTDR). This small adjustment would result in a base ROE of 7.01%.[254]

Third, using the A-rated Canadian utility bond index in the establishment of the base ROE operates to ensure that the annually adjusted ROE (as updated through the formula) and the base ROE are derived in the same manner. Dr. Cleary's estimated bond yield of 4.6% is very close to the A-rated Canadian utility bond index yield of 4.51%. The A-rated utility bond index yield is used in the annual ROE adjustment formula (as reflected by the LCBF + utility bond spread in the formula). Therefore, establishing the base ROE using the A-rated Canadian utility bond index yield (or Dr. Cleary's 4.6% estimate, which is very close to the exact figure from the index of 4.51%) ensures that every year, when the ROE is adjusted formulaically, the resulting updated ROE is using the same inputs as the base ROE. There is a clear benefit in terms of consistency and ongoing assurance that the fair return standard is met each year from having the base ROE and the annually adjusted ROE using the same, or very similar, inputs.

Fourth, the BYPRP approach has the benefit of being very flexible in establishing a base ROE that is reflective of the risk of Ontario's electricity distributors and transmitters. The

[252] Exhibit N-M2-CCC-9 and Exhibit N-M3-10-SEC-72 (Attachments). The average includes: Alectra Inc., Hydro One, Toronto Hydro, Grandbridge Energy Inc., and Londo Hydro Inc.
[253] Undertaking J5.3.
[254] 4.51% + 2.5% = 7.01%.

regulator's choice of an appropriate risk premium, which is a key input in the BYPRP, establishes directly its view of the risk of the companies that it regulates relative to the average company. If the OEB agrees that Ontario's electricity distributors and transmitters are some of the least risky companies to invest in, then the risk premium should be set towards the bottom of the range of risk premiums (2%-5%), as Dr. Cleary has by specifying the risk premium at 2.5%. If the OEB believes that Ontario's electricity distributors and transmitters are closer to the risk of an average company then it can specify the risk premium closer to the middle of the range of risk premiums (e.g., 3%-3.5%). In addition, if the risk of Ontario's distributors and transmitters changes relative to the average company over time, the OEB can simply adjust the risk premium at the next generic cost of capital proceeding while still maintaining the linkage to the utility debt costs.

Fifth, the result of Dr. Cleary's BYPRP approach is a base ROE that is reasonable and properly falls below the expected Canadian market return. Dr. Cleary's detailed analysis of historical and forecast Canadian market returns results in an accurate estimate of the long-term average expected Canadian market return of 7.5%.[255] Establishing the base ROE for Ontario's electricity distributors and transmitters below (i.e., 7.1%) the expected Canadian market return (i.e., 7.5%) properly reflects that these firms are lower risk than the market. Establishing the base ROE for low-risk rate-regulated utilities that is higher than the expected Canadian market return cannot be correct. Therefore, every other expert's recommendation, which suggests that the OEB establish the base ROE above 7.5%, also cannot be correct. This is common sense. There is no basis for low-risk assets (potentially, the lowest risk assets in the context of Ontario's rate regulated electricity distributors and transmitters) in an investors portfolio to be providing returns that are above the market average.

Sixth, CCC submits that Dr. Cleary's BYPRP approach is no more subjective than the approaches put forward by the other experts in this proceeding. Every estimation approach placed before the OEB in the current proceeding required the analyst (or expert) to apply their judgement at every step of the process. Using Concentric's CAPM approach as an illustrative example, Concentric made all of the following judgement calls, which together resulted in its CAPM-derived base ROE of 10.23% (or 10.21% as updated) for the North American electric proxy group[256]:

[255] Exhibit M4, pp. 83.
[256] Exhibit M2, p.9; and Undertaking J4.8.

- Applied both Canadian and U.S. government bond yields to determine risk-free rates
- Specified a proxy group to determine the average beta that included U.S. companies, companies that own significant generation assets, and companies with significant unregulated operations
- Used adjusted betas (as opposed to raw betas)
- Used both Canadian and U.S. market data to determine the MRP.[257]

Every single specification that the analyst makes to its estimation approach is subjective. Is it correct to use adjusted betas? Concentric thinks so. LEI and Dr. Cleary (and CCC) do not. There is no difference, in terms of subjectivity, between Concentric's decision to use a proxy group full of U.S. firms (and firms that own significant generation assets) and Dr. Cleary's determination that an appropriate risk premium for Ontario's utilities is 2.5%. These are all judgements made by the expert in their respective attempts to estimate an appropriate base ROE.

Dr. Cleary described his approach well in an exchange with Chief Commissioner Anderson, "I guess I'd call it "empirically informed judgement", if you will."[258] This is exactly what he did in his BYPRP approach, he applied empirically informed judgement to specify the inputs. He recognized that the cost of debt for Ontario's utilities is best reflected by the A-rated Canadian utility bond index (along with the consideration of other data points that are available). He also recognized that these utilities are on the low-end of the risk spectrum when determining where to place these utilities in terms of the range of risk premiums that are applied by finance professionals (and as described in corporate finance textbooks and readings used in the CFA and CPA program).[259]

CCC acknowledges that the AUC, in its 2024 Cost of Capital Decision, stated:

> "Under the utility bond risk premium approach, a required ROE is calculated by adding an equity premium to a utility bond yield. In past GCOC decisions, the Commission accepted the bond yield and utility bond yield approaches to be valid tools in estimating the cost of equity, as they are simple to use and conform to the basic principle that investors require a higher return for assets with greater risk. Although the Commission still considers the empirical basis of the utility bond yield methodology to be valid, for the purposes of this decision the Commission will not rely on the utility bond yield risk premium approaches used by Dr. Cleary and D. D'Ascendis.

[257] Exhibit M2, pp. 45-49, 63-70.
[258] Oral Hearing Transcripts, Volume 6, p. 188.
[259] Exhibit N-M4-EDA-5.

> Dr. Cleary's recommended risk premium of 2.50 per cent is subjective, not supported by any analysis and does not take into the account the changing market environment."[260]

In the same decision, the AUC also stated:

> "The model results are subject to a high degree of variability given the range of data sources, forecasts and assumptions that parties choose to use, and the judgment and experience of the expert doing the modelling."[261]

The AUC clearly acknowledges that judgement is involved by the experts in deriving the recommended ROEs from the various estimation approaches that were put forward in that proceeding. However, it takes issue with the subjectiveness and lack of analysis associated with Dr. Cleary's risk premium estimate. While we cannot be sure what precisely the AUC takes issue with, CCC submits that Dr. Cleary applies judgement in determining the appropriate specifications for the BYPRP approach similar to all the other experts in their estimation approaches. In terms of analysis, he considers the risks of rate-regulated utilities relative to the average company in the market and, on this basis, specifies a risk premium of 2.5% to reflect that these utilities are on the low-end of the risk spectrum.

Our best guess is that the AUC has mistakenly aligned the inclusion of many or detailed inputs in an estimation approach with that approach either being less subjective or more analytically sound. CCC agrees that the DCF and CAPM approaches appear to have more analysis supporting the result (and the models appear to be more scientific). There are many model inputs in those two approaches. However, the existence of many model inputs in no way means that these models are less subjective or more analytically sound. As discussed above, those models require judgement at every single step of model specification. In addition, as discussed in detail in section 3.3, CCC submits that the judgement applied by Concentric, Nexus and LEI in specifying their models is flawed.

With respect to the AUC's comment that Dr. Cleary's risk premium of 2.5% does not reflect changing market conditions, CCC disagrees. The risk premium applied in any given cost of capital proceeding can be adjusted, as necessary, to reflect current market conditions (and also the risks faced by the utilities to which the base ROE applies). In addition, the bond yield used in the BYPRP reflects current market data that is reflective of the cost of debt for Ontario utilities.

---

[260] Alberta Utilities Commission, Decision, Determination of the Cost of Capital Parameters in 2024 and Beyond, 27084-D02-2023, October 9, 2023, p. 37.
[261] Alberta Utilities Commission, Decision, Determination of the Cost of Capital Parameters in 2024 and Beyond, 27084-D02-2023, October 9, 2023, p. 38.

Finally, Dr. Cleary's BYPRM results in an appropriate base ROE as it does not directly use financial information from a proxy group of companies that are not the same as, or like, Ontario's electricity distributors and transmitters. The base ROE estimates of the other experts, while overstated due to the model specifications as discussed previously, can be said to be relevant for U.S. utility holding companies but not Ontario's rate regulated electricity distributors and transmitters. Nexus, in its presentation day materials, commented that "the probability that Dr. Cleary is measuring even the same concept as LEI, Concentric, or Nexus is infinitesimally small."[262] CCC agrees. Dr. Cleary has measured the risk of Ontario's utilities relative to the market in the determination of a base ROE. While Nexus, and the other experts, have measured the risk of largely U.S. holding companies, which have significantly higher risk than the Ontario distributors and transmitters, relative to the market. The base ROE calculated by Nexus, while certainly too high given the unrealistic growth rates and forecasts of future market returns that it applied, might be informative for a manufacturing company like Otter Tail Corporation but not Ontario's electricity distributors and transmitters.

For all the above reasons, CCC submits that a 7.1% base ROE, which excludes transaction costs, is appropriate for Ontario's electricity distributors and transmitters.

CCC would also like to comment on Concentric's evidence that compares authorized ROEs amongst jurisdictions more generally.[263] There is no reason that the OEB must fall in line with the approved ROEs in other jurisdictions. If the OEB agrees that the ROE is already too high, and risk has decreased since 2009, it has the responsibility to reduce the ROE. Setting the ROE in reference to other jurisdictions is a circular exercise and not appropriate.

As Dr. Cleary stated, with a base ROE of around 7%, Ontario's rate regulated utilities "would represent attractive investments because of the low-risk profile, and, at that rate, they would be earning an adequate required rate of return."[264]

CCC acknowledges that moving first and reducing the ROE below those set by other regulators is difficult. CCC submits that the OEB should lead on the cost of capital issues just as it has done, in the past, on performance-based regulation. The OEB is often the first to move on important, and complex, regulatory issues and this is no different. We believe that if the OEB moves first and makes a meaningful reduction to the ROE applicable to

[262] Nexus Presentation Day Materials, p. 19.
[263] Exhibit M2, pp. 79-81.
[264] Oral Hearing Transcripts, Vol. 6, p. 160.

Ontario's distributors and transmitters, regulators in other jurisdictions will follow suit (just as they have with respect to performance-based regulation).

While CCC believes that a base ROE of 7.1% meets the fair return standard for Ontario regulated distributors and transmitters, CCC acknowledges that the OEB may be of the view that this is a large reduction to occur all at once. What does a company do when it is specifying pricing for a product to maximize profits? It will raise prices in given increments and monitor the impact that the change in pricing is having on demand in order to optimize the price that it charges. The OEB can apply a similar, but directionally opposite, approach to the cost of capital. It can start reducing the ROE in the current proceeding and monitor the impact that it has on utilities.

If the OEB is concerned about the pace of the change, an alternative is to reduce the ROE to the half-way point between the current implied equity risk premium (550 basis points) and the implied equity risk premium of 397 basis points resulting from CCC's proposed base ROE of 7.1%. This would establish the base ROE at 7.87% in the current proceeding. If the OEB prefers this approach, it should acknowledge that this is a step-change relative to the current ROE and, directionally, further reductions may be needed in future cost of capital proceedings. The OEB can monitor whether this reduction to the allowed ROE has any negative implications for Ontario's electricity distributors and transmitters with the plan to continue to reduce the ROE further at the next generic cost of capital review assuming the macroeconomic environment is supportive of further reductions

3.5. CCC's Proposed Formulaic Annual Adjustment to the Return on Equity

LEI, Concentric and Dr. Cleary all recommended the continuation of a formulaic approach to resetting the ROE each year after the base ROE is established in the current proceeding. The three experts recommended the continued inclusion of the 30-year Government of Canada bond yield (LCBF) and a utility bond spread. However, the manner in which these bond yields are determined differ amongst the experts. There is also disagreement amongst the experts about the appropriate adjustment factors to apply to the LCBF and utility bond spread.

LEI recommended that the LCBF be determined based on an average of the forecast 30-year Government of Canada bond yield provided by the major Canadian banks and that the utility bond spread be based on a 12-month trailing average of the A-rated Canadian utility bond index.[265]

Concentric recommended that the LCBF be determined based on an average of the forecast 30-year Government of Canada bond yield from three Canadian investment banks (weighted at 75%) and the current 90-day average 30-year Government of Canada bond yield (weighted at 25%). The utility bond spread would be determined based on a 90-day average of the A-rated Canadian utility bond yield.[266]

Dr. Cleary recommended that the LCBF be determined based on the current 30-year Government of Canada bond yield on September 30 each year. Similarly, the utility bond spread would be determined based on the current A-rated utility bond yield on September 30 each year.[267]

CCC submits that Dr. Cleary's approach of using the current information on September 30 each year is simpler, more transparent and will result in more accurate results and should be applied for the determination of the LCBF and the utility bond spread. As noted by Dr. Cleary, forecasts of 30-year bond yields (using a similar methodology as suggested by LEI in this proceeding) have been about 0.4% higher than the actual bond yield that occurred in the subsequent year. Dr. Cleary further shows that if the current bond yield (at the end of September) was used for the upcoming year, the variance between the current bond yield and the actual bond yield is nearly zero.[268] CCC notes that using current data will align the formulaic approach with the utility bond yield included in Dr. Cleary's BYPRP, which has the benefit of providing for internal consistency as between the establishment of the base ROE and the annually adjusted ROE.

Currently, the OEB adjusts the LCBF and the utility bond spread by 50% of the annual change in those yields (relative to the yields when the base ROE was established).[269] LEI, Concentric and Dr. Cleary recommended changes to the 50% adjustment factor.

LEI recommended that the LCBF adjustment factor be changed to 0.26 and the utility bond spread adjustment factor be changed to 0.13. These values were determined by

[265] Exhibit M1, p. 92.
[266] Exhibit M2, pp. 95-96.
[267] Undertaking J5.3.
[268] Exhibit M4, Appendix A.
[269] Ontario Energy Board, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, p. 49.

multivariate regression analysis.[270] CCC submits that LEI's regression analysis is not designed correctly. It uses allowed ROEs applicable to U.S. utilities as the dependent variable and U.S. treasury bond yields and "Moody's seasoned Baa Corporate bond yields" as the independent variables. As CCC has argued previously, the use of U.S. authorized ROEs in the determination of the appropriate ROE for Ontario's utilities is not appropriate. In addition, the regression analysis is using U.S. treasury bonds and lower rated corporate bonds (relative to the A-rated Canadian utility bond index) to determine the adjustment factor. These are different than the yields that are being adjusted by the adjustment factor (i.e., Government of Canada bond yields and A-rated utility bond yields).[271] For these reasons, the OEB should disregard LEI's recommendation regarding the adjustment factors.

Concentric recommended that the LCBF adjustment factor be changed to 0.4 and the utility bond spread adjustment factor be changed to 0.33. These values were also determined by multivariate regression analysis.[272] Similar to the problems with LEI's regression analysis, Concentric also relies on U.S. authorized ROEs and U.S. treasury bond yields to determine its adjustment factors. In addition, the goodness of fit (as reflected by the R-Squared value) is low.[273] For these reasons, the OEB should disregard Concentric's recommendation regarding the adjustment factors.

Dr. Cleary recommended that the LCBF and utility bond spread adjustment factors be increased to 0.75. Dr. Cleary's analysis highlights that the approved ROE in Ontario as adjusted each year using the OEB-approved 0.50 adjustment factor has resulted in the approved ROEs being well in excess of the utilities' cost of equity (as the spread between the allowed ROE and the risk-free rate & utility bond yield has widened over time).[274]

CCC submits that the OEB should increase the adjustment factors for the reasons cited by Dr. Cleary. CCC believes that an increase in the adjustment factors to 0.75 is reasonable to allow for more of the annual change in bond yields (as reflected by the change in the LCBF and the utility bond spread) to be passed through to the annually adjusted ROE. There is an argument that there should be no adjustment factor (i.e., the entire change in annual bond yields should be reflected in the annually adjusted ROE). However, as CCC discusses in section 6.1, we have proposed that any changes to the ROE be implemented only in a

---

[270] Exhibit M1, p. 116.
[271] Exhibit M1, p. 116.
[272] Exhibit M2, p. 98.
[273] Exhibit M2, p. 106.
[274] Exhibit M4, p. 74.

utility's rebasing. Therefore, to limit the year-over-year volatility of changes in the bond yields (as reflected in a utility's ROE) a 0.75 adjustment factor is appropriate (which avoids utilities that rebase in different years potentially having widely different ROEs reflected in base rates).

CCC's preferred adjustment formula (inclusive of its proposed base ROE, initial LCBF and initial utility bond spread) is as follows:

ROE = 7.10% + 0.75 x (LCBF – 3.13%) + 0.75 x (UtilBondSpread – 1.39%).

If the OEB is concerned with the 0.75 adjustment factor applied to the LCBF and the utility bond spread as set out in Dr. Cleary's formula, maintaining the existing adjustment factor of 0.5 is the most reasonable of the other alternatives.

3.6. CCC's Proposed Capital Structure

As discussed previously, CCC does not believe that it is appropriate to continue to set a single average ROE for all Ontario rate-regulated utilities and use the equity thickness as the lever to reflect risk differences between sectors as the OEB has done historically. CCC submits that the ROE and the equity thickness are directly related and should be established by the OEB at the same time (as both must be considered in the determination of whether the fair return standard is met).[275]

In the context of CCC's submission that the ROE and capital structure be set for only the electricity distributors and transmitters in the current proceeding, CCC submits that an ROE of 7.1% with an equity thickness of 40% (i.e., an unchanged equity thickness) will fulfill the fair return standard.[276]

CCC notes that its proposed ROE and capital structure should apply to all electricity distributors and transmitters (including single-asset transmitters). With respect to single-asset transmitters, CCC submits these companies have similar risk as transmitters that own and operate multiple assets for the following reasons:

---

[275] To satisfy the fair return standard, the OEB needs to determine whether the ROE as applied to the deemed equity portion of rate base is reasonable (not just one of those two factors).
[276] In the future rebasing proceedings for Enbridge Gas and OPG, the OEB could consider moving all utilities to the same equity thickness so that the allowed ROE becomes directly comparable across the utilities (and is what is used to reflect differences in risk profiles).

- The regulatory framework (and ratemaking structure with the socialization of demand risk) "means that there is very little distinction in the risks faced by single-asset versus multi-asset transmission companies."[277]
- The single-asset transmitters operating in Ontario are relatively new and are operating newer assets (which are lower risk) than multiple asset transmitters.[278]

CCC does not believe that there is a valid reason to treat single asset and multiple asset transmitters differently from a cost of capital perspective. Therefore, an ROE of 7.1% and equity thickness of 40% should apply to all transmitters.

Alternatively, if the OEB is inclined to continue setting a single average ROE for all rate-regulated utilities in Ontario and using the capital structure as the basis to reflect differences in risks between sectors, then the capital structure for electricity distributors and transmitters should be reduced to 36% in the current proceeding for the reasons that follow.

CCC submits that a reduction of the equity thickness to 36% follows the rationale that electricity distributors and transmitters have lower risk than natural gas distributors and a different risk profile than OPG.

As noted previously, Ontario's electricity distributors and transmitters have lower risk now than they did in 2009, when the capital structure was last reviewed, and was maintained at 40% for electricity distributors.[279] The equity thickness for electricity transmitters was to be reviewed on a case-by-case basis but, as a practical matter, all electricity transmitters have been applied a 40% equity thickness since 2006.[280]

Electricity distributors and transmitters have lower risk than natural gas distributors due to the differential impact of energy transition (i.e., energy transition positively impacting electricity distributors and transmitters and negatively impacting natural gas distributors).

The OEB, less than a year ago, established 2024 rates (and relatedly, the cost of capital) for Enbridge Gas in a rebasing proceeding that had a very large focus on the potential impact

[277] Oral Hearing Transcripts, Vol. 3, p. 56.
[278] Oral Hearing Transcripts, Vol. 3, p. 57.
[279] Ontario Energy Board, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, p. 50. The OEB determined to maintain the 40% equity thickness in its 2009 Cost of Capital Report as was previously established in 2006.
[280] Exhibit M1, p. 141.

of energy transition-related risks on the company. In that proceeding, the OEB determined that a 38% equity thickness (which reflected an increase from 36%) is appropriate for Enbridge Gas in the context of the change in risk faced by the company.[281] CCC sees no reason that the capital structure for Enbridge Gas should be changed less than a year later.

On the basis of the lower risk faced by Ontario's electricity distributors and transmitters (and the OEB's very recent establishment of a 38% equity thickness for Enbridge Gas), if the OEB is setting a single ROE for all rate-regulated utilities in Ontario (which we say is not appropriate), the equity thickness for electricity distributors and transmitters should be reduced to slightly below the level applied to Enbridge Gas and be set at 36%.

The equity thickness for OPG should remain at 45% even if the OEB decides to establish a single ROE for all rate-regulated utilities in Ontario and be subject to review at the time of its next rebasing. This review should be comprehensive and consider energy transition-related risk for OPG and the offsetting special regulatory treatment that is applied (as was discussed previously).

With respect to Concentric's recommendation that the equity thickness be increased for electricity distributors and transmitters and natural gas distributors to 45% (to match the current equity thickness for OPG, with further changes to OPG in its next rebasing)[282], CCC submits that the proposal has no merit.

The rationale for Concentric's recommendation appears to be nothing more than a reference to the fact that the deemed equity ratios in Ontario are low compared to North American peers and that the Ontario utilities should have a deemed equity ratio at parity with their U.S. counterparts. The 45% equity thickness proposed is to move to a point approximately halfway between the Ontario level and the U.S. average.[283]

As discussed in detail previously, U.S. utilities have significantly higher risk than Ontario's utilities and there is no requirement that Ontario utilities have the same ROE or equity thickness as those utilities.

Also, as discussed previously, Ontario's electricity distributors and transmitters have lower risk than they had in 2009 (and relative to natural gas distributors). Therefore, there is no basis to increase the equity thickness for these utilities as recommended by Concentric.

---

[281] EB-2022-0200, Decision and Order, December 21, 2023, p. 68.
[282] Exhibit M2, p .136.
[283] Exhibit M2, pp. 136-137.

There is also no basis to increase Enbridge Gas's equity thickness less than a year after the OEB established it in a comprehensive review as part of Enbridge Gas's 2024 rebasing proceeding.[284]

[284] EB-2022-0200.

4. Short-Term Debt

CCC submits that LEI's recommendation with respect to the establishment of the deemed short-term debt rate (DSTDR), as updated, is largely appropriate.

CCC submits that the OEB should apply Option 1 for 2025 as set out in LEI's updated proposal. This means that the DSTDR would be based on the average of the 3-month Canadian Overnight Repo Rate Average (CORRA) futures rates for the next 12-month period (based on September 30 data) plus a spread based on the 2023 bank survey (and adjusted by adding historical observed difference between 3-month CORRA and 3-month Bankers' Acceptance (BA) rates) to establish the DSTDR.[285]

For future years, assuming the spread value normalizes, the OEB should apply Option 2 in LEI's updated proposal. This means that the DSTDR would be based on the average of the 3-month CORRA futures rates for the next 12-month period (based on September 30 data) plus a spread based on the historical 12-month spread between the A-rated utility index.[286]

CCC submits that the DSTDR should continue to be used directly in rate-setting to establish the short-term debt cost for Ontario's electricity distributors and transmitters (and be applied to the deemed short-term debt portion of the capital structure).[287]

Similarly, the OEB should continue its approach of using actual short-term debt costs for Enbridge Gas and OPG (and updated only at rebasing).[288] However, as CCC has proposed that the cost of capital parameters be updated for Enbridge Gas and OPG at their next rebasing proceedings (including a comprehensive review of the ROE and capital structure) as opposed to the current proceeding, these utilities should be allowed to apply for a different approach to short-term debt if they believe that is appropriate.

[285] Undertaking J2.2, p. 3.
[286] Undertaking J2.2, p. 3.
[287] Ontario Energy Board, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, p. 56.
[288] Ontario Energy Board, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, p. 56.

5. Long-Term Debt

Similar to CCC's views on establishing the LCBF and the utility bond spread for the purposes of the annual adjustment formula, CCC submits that the OEB should establish the deemed long-term debt rate (DLTDR) based on the current 30-year Government of Canada bond yield on September 30 each year plus the utility bond spread (based on the current A-rated utility bond yield) on the same date each year. This results in a DLTDR of 4.51% for 2025.[289]

As noted previously, CCC submits that Dr. Cleary's approach of using the current information available on September 30 each year is simpler, more transparent and more accurate. This will also align the approach to establishing the DLTDR, the annual adjustment formula and the base ROE (through the BYPRP).[290]

The OEB should continue its current approach of using the actual long-term debt costs for rate-setting purposes for electricity distributors and transmitters and the DLTDR should continue to operate as a cap for those utilities (when the actual cost of debt is higher than the deemed cost of debt).[291] CCC submits that the same approach should apply to Enbridge Gas and OPG. However, as CCC has proposed that the cost of capital parameters be updated for Enbridge Gas and OPG at their next rebasing proceedings (including a comprehensive review of the ROE and capital structure) as opposed to the current proceeding, these utilities should be allowed to apply for a different approach to long-term debt if they believe that is appropriate.

With respect to financing costs associated with obtaining debt, CCC submits that the current approach of recording the actual transaction cost as an interest expense and amortizing the transaction cost over the term of the debt instrument using the effective interest methodology[292] remains appropriate. CCC notes that this approach is reasonable as it is based on the actual debt-related transaction costs incurred by a utility (and amortizing over the term of the underlying debt instrument is logical as it matches the recovery of the cost with the term of the underlying debt).

---

[289] Undertaking J5.3.
[290] CCC notes that the base ROE that it has proposed considers a few other data points for establishing the utility bond yield of 4.6% included in the estimate, which is slightly higher than the utility bond yield resulting from the approach described here of 4.51%.
[291] Exhibit M1, p. 93.
[292] Exhibit M1, p. 93

CCC notes that the issues associated with the OEB's current approach to cost recovery for debt-related transaction costs and equity-related transaction costs are different. The recovery of debt-related transaction costs is currently based on actual costs. Therefore, the current approach is reasonable. In contrast, the recovery of equity-related transaction costs is currently based on a deemed transaction cost (i.e., 50 basis points) and this deemed cost applies to all utilities as part of the approved ROE (regardless of the actual equity-related transaction costs that are incurred). This is not appropriate and should be rectified in the manner proposed by CCC in section 3.3.

6. Implementation of the Cost of Capital Parameters

CCC's submission with respect to implementation timing, the timing of annual cost of capital parameter updates, the monitoring of the reasonableness of the cost of capital, and the timing of the next generic cost of capital review is set out below.

6.1. Implementation Timing

CCC does not agree with Concentric's proposal that the changes to the cost of capital parameters and/or capital structure resulting from the OEB's determination in the current proceeding should be implemented in the next rate year following the OEB's decision regardless of whether that change happens in the middle of an existing rate term.[293] We also do not agree with LEI's proposal that there should be an option for utilities to apply for the implementation of cost of capital parameter changes in advance of rebasing if a given utility has more than 60% of the rate term remaining and the deviations in the cost of capital parameters are material.[294]

CCC submits that the OEB should establish the ROE and capital structure for only Ontario's electricity distributors and transmitters in the current proceeding for the reasons described previously. In the context of CCC's submission whereby only the ROE is changed (to 7.1%) for Ontario's electricity distributors and transmitters, this change, as updated each year using the final OEB-approved annual adjustment formula, should be implemented for each utility at the time of their next rebasing (and not before then). Similarly, any changes to the deemed cost of debt (both short-term and long-term), to the extent those deemed rates flow into a utility's cost of capital[295] for ratemaking purposes, should be implemented at each utility's next rebasing.

CCC notes that the OEB recently issued its 2025 cost of capital parameter update letter. In the letter, the OEB noted that the updated 2025 cost of capital parameters are being established on an interim basis as to not restrict the OEB's determinations in the current proceeding.[296] With respect to the utilities that are rebasing for 2025 rates, in the context that the OEB has set the updated 2025 cost of capital parameters on an interim basis, these utilities should be applied the ROE/capital structure resulting from the OEB's

[293] Exhibit M2, pp. 148-149.
[294] Exhibit M1, pp. 162-163.
[295] As we have argued, the DSTDR should be used to set rates for electricity distributors and transmitters. However, the actual long-term debt costs (not the DLTDR) should be used for ratemaking purposes.
[296] OEB 2025 Cost of Capital Parameters Update Letter, October 31, 2024, pp. 2-3.

determinations in the current proceeding (assuming the relevant settlement proposals and decisions, as applicable, explicitly allow for such a change).[297]

CCC submits that there are no mechanisms available for utilities during their incentive ratemaking terms to make adjustments to base rates (unless specific allowable adjustments are directly approved for future years at the time that the base rates were established). The cost of capital forms part of a utility's base rates and, for utilities that use the OEB's standard Price Cap IRM, those base rates are inflated each year by an inflation minus productivity formula in the four years following the rebasing (typically, with no other changes to base rates allowed). For utilities that elect to use a Custom IR approach, the allowable annual adjustments to base rates are specifically described in the OEB's decision (or approved settlement proposal). There is no basis to allow for changes to base rates that are outside of the mechanisms that were specifically approved at a utility's most recent rebasing.

CCC also notes that when the OEB is considering whether the rates resulting from a rebasing application are just and reasonable, it reviews the overall bill impacts (which would notionally include any changes to the cost of capital) in coming to its determination. To allow for changes to base rates (and resulting changes to the bill impacts) that the OEB already determined were just and reasonable after they were established is not appropriate.

Finally, as a practical matter, determining the appropriate change to rates to reflect a change to the cost of capital in the middle of a Price Cap IRM term (which is used by most of Ontario's electricity distributors) is difficult. To implement this kind of change, the OEB would need to determine the existing revenue requirement in the year that the cost of capital adjustment would apply to operationalize any change (and under Price Cap IRM, it is the rates that are inflated not the revenue requirement). The OEB could not simply go back to the test year, change the ROE/capital structure, calculate the revenue requirement and associated rates, and then escalate those rates using the I-X formula from that new starting point as this would amount to setting an earlier effective date for the updated OEB-approved ROE/capital structure than 2025.

Overall, CCC submits that the implementation of changes to the cost of capital in the middle of a utility's ratemaking term is both not appropriate and difficult to operationalize.

[297] CCC notes that some utilities that are rebasing for 2025 already have final decisions and/or settlement proposals filed with respect to 2025 rates. And most, if not all, will have final decisions issued prior to when the decision in the current proceeding is issued.

With respect to updates to the cost of capital parameters for Enbridge Gas and OPG, as discussed previously, CCC submits that any update should be based on evidence filed in each of those utilities' next rebasing proceedings.[298] The OEB should perform a comprehensive review of the risks faced by Enbridge Gas and OPG to determine both the appropriate ROE and equity thickness together in the same proceeding. CCC does not believe that this will cause a significant increase in the evidence that needs to be filed in those proceedings as Enbridge Gas and OPG, as far as CCC is aware, always file evidence with respect to their respective capital structures (and this proposal only adds the need to file evidence supporting the appropriate ROE). Therefore, CCC does not believe that its proposal, in this regard, materially increases regulatory burden.

6.2. Timing of Annual Cost of Capital Parameter Updates

CCC submits that the annual cost of capital parameter updates should occur at around the same time of the year as they do currently (i.e., late October). CCC's proposed DSTDR, DLTDR, and inputs to the annual adjustment formula require data that is available after September 30 in a given year. Therefore, the cost of capital parameter updates should not occur before that time.

The OEB should continue to use the annual cost of capital parameter update letter to reaffirm that the ROE meets the fair return standard.

6.3. Cost of Capital Monitoring

CCC submits that the OEB should continue with its current approach of monitoring the cost of capital through quarterly reports prepared for internal review purposes. As noted by LEI the quarterly reports should include: (a) analysis of the ROE, DLTDR and DSTDR using updated data (relative to the parameters published in the most recent annual cost of capital update); (b) a discussion of trends regarding macroeconomic factors; (c) and a discussion of the key factors driving these trends.[299]

In addition, the OEB should review credit reports (including whether any changes were made due to the regulatory framework) and monitor debt and equity issuances (including whether there were any difficulties in securing debt or equity investments) as

[298] As discussed previously, ENGLP should be applied the same cost of capital treatment as Enbridge Gas in its rebasing applications following the establishment of the cost of capital for Enbridge Gas.
[299] Exhibit M1, p. 147.

recommended by LEI.[300] CCC notes that this may require the filing of additional reporting by utilities, which can occur annually or on as needed basis. However, this additional reporting will be very useful to the OEB in monitoring the reasonableness of the cost of capital over time.

6.4. Timing of Generic Cost of Capital Proceedings

CCC submits that the OEB should hold a generic cost of capital proceeding with respect to the cost of capital applicable to Ontario's electricity distributors and transmitters every 5 years.

As noted previously, the cost of capital for Enbridge Gas and OPG should be established in their next rebasing proceedings (including a comprehensive review of the risk faced by these utilities in order to determine the appropriate ROE and equity thickness). Given that these utilities are on 5-year rebasing cycles, their cost of capital would also be updated every 5 years.

[300] Exhibit M1, p. 150.

7. Prescribed Interest Rates for Deferral and Variance Accounts and Construction Work in Progress

CCC submits that the OEB's current approach of applying a short-term debt rate to deferral and variance account (DVA) balances and a mid-term debt rate (as reflected by the FTSE Canada Mid-Term Bond Index All Corporate Yield) for Construction Work in Progress (CWIP) continues to be appropriate for the reasons described by LEI.[301] More specifically, with respect to the calculation of the short-term debt rate applicable to DVA balances, the OEB should apply the same approach that CCC recommended for calculating the DSTDR in section 4 of the submission.

CCC notes that Concentric recommended that a short-term debt rate apply to DVAs where the balance is cleared within one year and the weighted average cost of capital (WACC) be applied to DVAs where the balance is not cleared within one year. Concentric also stated that it was reasonable to separate short-term accounts and long-term accounts using the OEB's definitions for Group 1 and Group 2 accounts.[302] Concentric also recommended that the WACC be applied to CWIP.[303]

CCC submits that Concentric's recommendation to apply the WACC to DVA balances that are not cleared within one-year (long-term DVAs) and CWIP is not appropriate.

With respect to the application of the WACC to DVA balances, CCC submits that this will result in unintended consequences that the OEB should seek to avoid. First, the application of the WACC rather than the short-term debt rate, will increase the carrying cost associated with DVA balances. This will potentially lead to a reluctance from ratepayer groups and the OEB to support the establishment and utilization of longer-term DVAs as a regulatory tool. This will reduce the OEB's flexibility to address variable or unknow costs. In addition, due to the higher carrying costs, there will be increased pressure on the OEB to dispose of the longer-term (or Group 2) balances every year. This will create incremental regulatory burden as the disposition of Group 2 accounts requires a prudence review, which will now potentially have to occur every year (instead of once every 5 years). This does not work well with the OEB's current approach of addressing annual IRM applications by way of delegated authority. Finally, the application of the WACC to DVA balances creates a perverse incentive for utilities to seek to record operating costs in DVAs (as opposed to being recovered directly in base rates) in order to derive a return from that spending.

[301] Exhibt M1, p. 168.
[302] Exhibit N-M2-OEB Staff-27.
[303] Exhibit M2, p. 156.

With respect to the application of the WACC to CWIP, CCC submits that this will result in the capitalization of the return component on assets that will eventually form part of rate base. More specifically, by applying the WACC to CWIP, the value of the construction project now includes a return component. When that construction project is placed into service, and the asset value moves from the CWIP account to rate base, the utility will begin earning a return on the rate base value, which already notionally includes a return component. Therefore, the utility will effectively earn a return twice on the same asset. This is not appropriate.

For the above reasons, CCC submits that the OEB should decline Concentric's recommendation to apply the WACC to long-term DVA balances and CWIP amounts. Instead, the OEB should continue its current approach of applying a short-term debt rate to DVA balances and a mid-term debt rate to CWIP amounts.

8. Cloud Computing Deferral Account

CCC submits that any balances that accrue in the Cloud Computing Deferral Account should be applied the short-term debt rate calculated in the same manner as CCC recommended for calculating the DSTDR in section 4 of the submission.

CCC submits that the Cloud Computing Deferral Account is no different than any other DVA that is available to utilities. It records costs that are incremental to amounts that are already included in base rates. The risk profile of cloud computing-related costs is no different than other costs recorded in the various DVAs available to utilities. If the cloud computing-related costs recorded in the account were prudently incurred then cost recovery will be granted by the OEB at the time the utility seeks disposition. This is the same test that is applied to balances in all Group 2 accounts.

CCC notes that LEI recommended that the OEB should employ a deemed capital additions approach, which allows the application of the deemed WACC on the unamortized portions of cloud computing contracts.[304] When asked whether its recommendation is in respect to the interest charges applied to the Cloud Computing Deferral Account or for the treatment of unamortized cloud computing costs at rebasing, LEI responded that its recommendation is related to a utility's next rebasing.[305]

CCC submits that the treatment of unamortized cloud computing costs is appropriately addressed at rebasing when a utility brings forward those costs. The OEB can determine the appropriate treatment at that time in the context of the actual cloud computing-related costs that were incurred and the cost recovery proposal made by the utility.

~ All of which is respectfully submitted ~

[304] Exhibt M1, p, 175
[305] Exhibit N-M1-22-CCC-9.