EB-2024-0063

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act,* 1998, S.O. 1998, c.15 (Schedule. B);

AND IN THE MATTER OF a generic proceeding commenced by the Ontario Energy Board on its own motion to consider the cost of capital parameters and deemed capital structure to be used to set rates.

COMPENDIUM OF THE CANADIAN MANUFACTURERS AND EXPORTERS

(Nexus Witness Panel)

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undertake business/investment activities of similar (or like) risk, the ownership type/structure should not matter.

LEI recommends that the OEB continue with the status quo as the alternative does not meet the FRS (which is a legal requirement, as highlighted in the guiding principles described in Section 3.1) and the general principles of corporate finance and valuation.

LEI recommendations - Issue 1

- The OEB's existing methodology implicitly accounts for differences in sources of funding when approving rate applications. LEI recommends that this aspect of the OEB methodology should be retained.
- Consistent with the OEB's existing policy, the approach to setting the cost of capital parameters and capital structure should not depend on a utility's ownership structure. LEI believes the status quo is consistent with the FRS and Canadian Supreme Court judgement(s).

4.2 General issues – risk factors to be considered in determining the cost of capital parameters and capital structure

Issue 2: ***What risk factors*** (including, but not limited to, energy transition) ***should be considered***, and ***how should these risk factors*** under the current and forecasted macroeconomic conditions ***be considered in determining the cost of capital parameters and capital structure***?

The two key risk factors that need to be considered when determining the cost of capital parameters and capital structure are (i) business risks and (ii) financial risks. While energy transition risk has been specifically mentioned in Issue 2, one can reasonably argue that it is part of business risk, which can ultimately impact the bottom line (i.e., leading to a change in financial risks/returns).[121]

Business risks and financial risks are related to uncertainty surrounding a company's operating earnings and its ability to finance its investments. For example, the AUC defines business risk as follows: *Business risk represents the perceived uncertainty in future operating earnings before the impact of financial leverage (EBIT) and, hence, determines the capacity for a business to be financed with debt as opposed to equity.*[122] Separately, financial risks are primarily linked to a company's ability to continue to finance its capital needs and growth opportunities by attracting investors at reasonable terms.

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[121] Credit rating agencies (such as S&P Global Ratings and DBRS Morningstar) also consider energy transition risk as part of business risks, which may ultimately impact financial risks/returns, when assessing ratings for regulated entities. Sources: S&P Global Ratings. Sector-Specific Corporate Methodology. April 4th, 2024. Page 147; DBRS Morningstar. Risks of the Green Energy Transition for U.S. Regulated Electric Utilities. May 21st, 2021.

[122] AUC. Decision 20622-D01-2016 - 2016 Generic Cost of Capital. October 7th, 2016. Page 115.

The riskier the investment's cash flows, the greater its cost of capital.[123] The risk factors can broadly be categorized as un-diversifiable (or unavoidable) risks inherent in the market (sometimes referred to as systematic risks) and company/asset-specific risks (sometimes referred to as unsystematic risks). Regulators typically adjust the cost of capital parameters and capital structure in response to changes in systematic risks. Examples of systematic risks include macroeconomic risk factors such as interest rates, inflation and recessions, regulatory risk, and policy risk.

4.2.1 Status quo

The OEB sets a uniform ROE for all regulated entities. However, per its stated policy, it undertakes a full reassessment of a utility's capital structure in the event of significant changes in the company's business and/or financial risk.[124]

As such, the OEB typically assesses the major risk factors following a utility's application for a change in equity thickness. The most recent assessments for electricity distributors were performed in 2006 (2006 report), Enbridge Gas in 2023 (EB-2022-0200), and OPG in 2017 (EB-2016-0152).[125]

Macroeconomic risk factors such as higher interest rates are not explicitly considered in these proceedings because they are intended to be embedded in the allowed ROE, DLTDR, and DSTDR. Further, utilities' ability to manage inflation depends on the design of IR mechanisms and hence, can be discussed as part of regulatory risk.

The aforementioned proceedings considered risks that can be grouped into the following business risk factors:

1. **Energy transition risk** refers to the 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). Notably, OEB's 2023 decision for Enbridge Gas considered energy transition risk to be one of the key reasons for an increase in business risk since the legacy utility rates were last rebased in proceedings initiated in 2011.[126]
2. **Volumetric risk** refers to the uncertainty in demand and consumer additions over the forecasting period, which may increase the likelihood of a forecasting error. A significant

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[123] CFA Institute. Cost of capital. Accessed on April 29th, 2024.

[124] OEB. EB-2009-0084. Report of the Board on the Cost of Capital for Ontario's Regulated Utilities. December 11th, 2009.

[125] Although the OEB policy states that they assess the capital structure for electricity transmitters on a case-by-case basis, the OEB currently allows an equity ratio of 40% (same as electricity distributors) to electricity transmitters. To the best of LEI's knowledge, the OEB has not separately assessed the risk factors for electricity transmitters.

[126] OEB. EB-2022-0200. Decision and Order. December 21st, 2023. Page 67.

forecasting error (if beyond the scope of relevant DVAs available to utilities) may lead to a material under-recovery or over-recovery of revenue.

3. **Operational risk** refers to the uncertainties and hazards a company faces when it pursues its day-to-day business activities.[127] Examples of operational risk factors include the degradation of aging nuclear power station components (OPG), impacts of meteorological/geological events on gas pipeline infrastructure (Enbridge Gas), and the geographic size and isolation of the distributor's service area (electricity distributors). In 2014, the OEB considered the addition of 48 hydroelectric facilities to OPG's rate base since OEB's previous review to have reduced the business risk for OPG as the share of hydroelectric assets in the rate base increased (OEB considered hydroelectric facilities to be lower risk than nuclear facilities).[128]

4. **Regulatory risk** refers to the impacts of OEB policies/regulatory mechanisms. For instance, in addition to the reduction of operational risk described above, the OEB also considered the addition of several DVAs since its last review (particularly the addition of a new pension variance account) to have reduced business risks for OPG. In 2017, the transition to incentive-based rates was considered a factor increasing OPG's business risks in its rate application, however, the OEB did not accept this argument.[129]

5. **Policy risk** refers to the impacts of Ontario, federal or municipal government policies/legislations. For instance, introducing the federal carbon price was considered to increase Enbridge Gas' risk by making alternative heating technologies more attractive. Policy risk can also increase when rates increase significantly in a short period of time, typically within 1-2 years (such as when higher natural gas prices in 2022 lead to dramatic increases in electric and gas distribution rates in many jurisdictions), triggering affordability concerns for customers. In such scenarios, the risk of rate freezes is higher.

The assessment of financial risks 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. S&P Global Ratings ("S&P Global") and DBRS Morningstar ("DBRS") rely on several key credit metrics, such as: (i) Debt/EBITDA, (ii) Funds from Operations ("FFO")/Debt, (iii) FFO/Interest, (iv) Cashflow from Operations ("CFO")/Debt, and (v) EBIT/Interest.[130,131] Figure 14 provides a brief description of these metrics.

[127] Investopedia. Operational Risk Overview, Importance, and Examples. Updated; January 16th, 2023.

[128] OEB. EB-2013-0321. Decision with Reasons. November 20th, 2014. Pages 112-115.

[129] OEB. EB-2016-0152. Decision and Order. December 28th, 2017. Page 101.

[130] S&P Global Ratings. *Corporate Methodology: Ratios And Adjustments.* November 19, 2013.

[131] DBRS Morningstar. *Methodology. Rating Companies in the Regulated Electric, Natural Gas and Water Utilities Industry.* September 2019

Figure 14. Description of key credit metrics (not exhaustive)

Credit metric	Description
Debt/EBITDA	▪ Evaluates a company's ability to pay its debts ▪ A higher value suggests a longer time may be needed to pay debt, and thus is correlated with lower credit rating
FFO/Debt	▪ Assesses extent to which company is leveraged ▪ A lower value suggests higher leverage levels, and is correlated with lower credit rating
FFO/Interest	▪ Assesses the ability of a company to service its interest expenses ▪ A higher value suggests sufficient cashflows to service interest payments, and may support higher credit rating
CFO/Debt	▪ Assesses the leverage but evaluates the extent to which the company's operating cashflows can repay its debt obligations ▪ Like FFO/Debt, a lower value is correlated with a lower credit rating
EBIT/Interest	▪ Measures a company's earnings over its interest payments. ▪ A higher value suggests better financial health of the firm, and correlates to a higher credit rating

Notes: Key terms defined as follows:

"Debt" defined as total debt, including long-term and short-term borrowing.

Earnings before Interest, Taxes, Depreciation and Amortization ("EBITDA") defined as revenues minus operating expenses (excluding depreciation, amortization, and non-current asset impairment and impairment reversals).

Funds from operations ("FFO") represents a company's ability to generate recurring cash flows from operations (S&P Ratings defines it as EBITDA minus cash interest paid minus cash taxes paid).

"Interest" defined as total interest expense.

Cash from operations ("CFO") is also referred to as operating cash flow. This measure takes reported cash flows from operating activities (as opposed to investing and financing activities).

4.2.2 Relevant jurisdictional review

In this section, LEI has reviewed the risk factors considered in Alberta, Australia and British Columbia. These risk factors can largely be grouped into the existing risk categories considered by the OEB in recent assessments.

Alberta:

The AUC, in its October 2023 decision associated with *the Determination of Cost-of-Capital Parameters in 2024 and Beyond*, identified three major risk factors as described below:

1) **Macroeconomic factors**: The AUC acknowledged that increasing interest rates and inflation since 2018 resulted in higher capital costs. However, it did not consider these factors to lead to higher approved ROEs or deemed equity thickness. Utilities in Alberta are *largely isolated from broader macroeconomic factors* because of certain regulations such as performance-based ratemaking ("PBR") for distribution utilities and cost-of-service ("COS") regulation for transmission utilities. The AUC stated that regulations provide utilities a reasonable opportunity to recover costs, including those directly and indirectly

affected by interest rates and inflation. PBR plans for distributors include inflation as a direct input into the PBR formula while COS regulation affords transmitters *a reasonable opportunity to recover all reasonable forecast cost increases related to the safe, reliable and efficient provision of services to customers over the future test period*;[132]

2) **Regulatory risk**: The utilities claimed that regulatory risks in Alberta have increased since 2018. The identified risks included lower deemed equity thickness and lower approved ROEs than those awarded in other North American jurisdictions, regulatory lag, stranded asset risk, and a decline in rating agency perceptions of the Alberta regulatory regime from *most credit supportive* to *highly credit supportive*. However, the AUC did not consider the claims to be valid adding *Alberta utilities have low earnings volatility, low business risk ratings and, operate within a regulatory framework that encourages and rewards utility-driven initiatives, projects, and investments in cost reduction and efficiency improvement that can lead to earnings in excess of approved ROEs*;[133] and

3) **Decarbonization**: The utilities argued that carbon reduction goals are generally more aggressive and difficult in Alberta than decarbonization policies in other jurisdictions. However, the AUC concluded that the utilities provided little or no evidence to indicate that they have experienced *any significant increase in risk related to customers changing behavior, a reduction in natural gas demand, complications related to electrification, or factors that might impact their operations*.[134]

Australia

The AER, in its February 2023 *Rate of Return Instrument* identified three major risk factors as described below[135]:

1) **Demand risk**: The demand risk refers to the forecast error in demand. The AER considers the revenue or price-setting mechanism to mitigate the risk. Under a price cap, NSPs can mitigate the risk by restructuring tariffs through higher fixed charges set to offset decreasing demand. Under a revenue cap, NSPs can mitigate the risk through price adjustments in subsequent years;

[132] AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023. Page 58.

[133] AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023. Page 59.

[134] AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023. Page 60.

[135] AER. Rate of return instrument. Explanatory statement. February 2023.

2) **Inflation risk**: The AER finds that regulated NSPs face less inflation risk than unregulated entities, since fluctuations in inflation are reflected in CPI-X, where CPI is the Consumer Price Index, and X is the pricing adjustment mechanism;[136] and

3) **Interest rate risk**: Movements in the interest rate affect the financing costs of customers. The AER states that the regulatory framework effectively reduces the risk. It notes that *the rate of return derived in 2022 is higher than that derived in 2018 because underlying market interest rates have risen in recent years*.[137] Moreover, the AER acknowledges concerns regarding the sufficiency of the ROE during a low-interest rate period, and published a paper[138] that considered the potential consequences of low-interest rates, and investigated the need to adjust the approach to the rate of return. The paper finds that the overall rate of return achieved under the current regulatory framework during the low-interest rate period was sufficient.

British Columbia

The British Columbia Utilities Commission ("BCUC"), in its September 2023 decision associated with the *Generic Cost of Capital Proceeding (Stage 1)*, identified seven major risk factors as described below[139]:

1) **Economic conditions**: FortisBC claimed that 'economic condition risk' has increased significantly due to inflation.[140] The BCUC disagreed with the assessment and finds the risk has remained unchanged since 2016 (for FEI) and 2013 (for FBC)[141]. It added that the risk does not affect FortisBC's ability to access capital or impact cash flow from customers since its O&M expenditures and growth capital are indexed into a composite inflation factor and are recoverable from ratepayers;

2) **Political risk**: FEI noted that the energy transition risk is apparent in BC's CleanBC Roadmap to 2030 ("Roadmap"), which sets out a greenhouse gas reduction obligation for

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136 The CPI number is actual CPI measured by the Australian Bureau of Statistics, and the x factor represents the rate of change in required revenue (in real dollars) each year to recover costs over the regulatory period. For both electricity distribution and transmission, the CPI-X methodology is used to index the allowed revenue. For electricity distributor, the control mechanism or some incentive-based variant for standard control services must be of the prospective CPI minus X form; for electricity transmitters, the CPI-X is applied in escalating the maximum allowed revenue for the provider for each regulatory year of a control period. For gas utilities, the National Gas Rules ("NGR") is less prescriptive regarding inflation and does not explicitly state how the capital base is to be indexed. Source: AER. Final position. Regulatory treatment of inflation. December 2020.

137 AER. Rate of return instrument. Explanatory statement. February 2023. Page 9.

138 AER. Term of the rate of return & Rate of return and cashflows in a low interest rate environment – Final working paper. September 2021.

139 BCUC. Decision and order G-236-23. Generic cost of capital proceeding (Stage 1). September 5th, 2023.

140 FortisBC is the collective name of FortisBC Energy Inc. ("FEI") and FortisBC Inc. ("FBC"), which are the benchmark utility for natural gas utilities and electricity utilities, respectively.

141 The BCUC published the most recent proceeding in 2023 and the previous proceeding for natural gas utilities in 2016 and for electricity utilities in 2013.

natural gas utilities. The BCUC agreed with FEI and noted that the energy transition poses uncertainty regarding the role that BC's natural gas utilities will play and that there is *a growing bias against the use of natural gas on the part of multiple policymakers*.[142] The BCUC found the political risks for natural gas utilities have increased significantly since 2016. The BCUC agreed with FBC that the political risk is lower for electricity utilities adding that *the Energy Transition that limits on the future growth prospects of FEI is mirrored in expanded FBC growth prospects*[143];

3) **Indigenous rights and engagement risk**: The risk refers to the potential for utility operations to be impacted by policy or legislation regarding *Aboriginal rights and title or by Indigenous groups intervening directly in the utility regulatory process or by asserting Aboriginal rights and title*.[144] Utilities with operations in areas not covered by treaty, meaning the land is unceded, may be subject to legal claims for title in the future. FortisBC assessed the risk as higher compared to that in 2016/ 2013. The BCUC agreed with the conclusion but could not determine the accurate magnitude of the difference. BCUC noted that although costs associated with the risk are recoverable through rates and hence are typically a ratepayer risk, there is a perceived risk by investors since *FortisBC's commitment to developing meaningful relationships with Indigenous communities cannot fully mitigate investors' perception of Indigenous risk*[145];

4) **Energy price risk**: Energy prices impact a utility's business risk as prices can influence consumer energy choices. FEI claimed the energy price risk is higher than that in 2016 partially because of volatility in natural gas prices, the increased weather events, forecasted LNG demand growth, and forecasted decrease in oil production. The BCUC agreed with FEI and noted that ratepayers largely bear the increase in energy price risk. However, the BCUC considers that government policies encouraging decarbonization may diminish natural gas' relative price advantage over electricity, therefore increasing perceived risk among investors, which could impact investors' expected return;

5) **Demand/market risk**: FEI stated that the worsening of customers' perception of natural gas and the development of new electric technologies could decrease demand for natural gas. While the BCUC did not consider declining market share necessarily represented declining revenues or an inability for utilities to achieve allowed ROEs, the BCUC considered *the declining market share would be perceived negatively by investors thereby affecting the shareholders' expected returns*[146];

6) **Operating risk**: FortisBC submitted operating risks such as asset concentration, technologies employed to deliver service, service area geography, human error, weather,

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[142] BCUC. Decision and order G-236-23. Generic cost of capital proceeding (Stage 1). September 5th, 2023. Page 36.

[143] Ibid. Page 54.

[144] Ibid. Page 36.

[145] Ibid. Page 38.

[146] Ibid. Page 49.

public attitudes towards the fossil-fuel industry, and cybersecurity have increased compared to that in 2016/2013, but the BCUC found that the operating risk remained unchanged as no evidence was provided to indicate otherwise; and

7) **Regulatory risk**: FortisBC noted that there is an increase in overall regulatory risk, adding that *regulatory uncertainty gives rise to the risk that the allowed return on rates may not meet the [FRS], or that necessary investments are not approved*. It also claimed that risk associated with regulatory lag and ultimate approval of cost recovery also increased since 2016/2013 caused by increased requirements for stakeholder consultation, environmental reviews, and Indigenous rights and title. However, the BCUC decided that it was not persuaded by the submitted evidence and found that FortisBC's regulatory risk remained unchanged since 2016/2013.

The summary of the jurisdictional analysis is shown in Figure 15 below.

Figure 15. Summary of the jurisdictional review (risk factors considered by regulators)

Jurisdiction	Risk factor
Alberta	• **Macroeconomic factors**: Utilities are largely isolated from broader macroeconomic factors • **Regulatory risk**: Utilities operate within a supportive regulatory framework of low regulatory risk • **Decarbonization**: Utilities provided little or no evidence to indicate that they have experienced any significant increase in risk related to decarbonization
Australia	• **Demand risk**: NSPs mitigate the risk through the revenue or price-setting mechanism • **Inflation risk**: Regulated NSPs face less inflation risk than unregulated NSPs • **Interest rate risk**: The current regulatory framework effectively reduces the interest rate risk
British Columbia	• **Economic conditions**: The economic condition risk has remained unchanged for FEI and FBC since 2016 and does not impact their ability to access capital or affect cash flow from customers • **Political risk**: The political risk has increased significantly for FEI (and other gas utilities) and decreased for FBC (and other electric utilities) due to Energy Transition • **Indigenous rights and engagement risk**: Utilities with operations in areas not covered by treaty may be subject to legal claims for title in the future • **Energy price risk**: FEI faces higher risk than that in 2016 which may be offset by policies encouraging decarbonization • **Demand/market risk**: Customers' worsened perception of natural gas and the development of new electric technologies could decrease demand for natural gas, which would be perceived negatively by investors thereby affecting investors' expected return • **Operating risk**: The operating risk has remained unchanged for FEI and FBC since 2016 as no evidence suggests otherwise • **Regulatory risk**: The regulatory risk has remained unchanged for FEI and FBC since 2016

4.2.3 Potential alternatives

In addition to the business risks and financial risks considered by the OEB in recent applications (see Section 4.2.1), the OEB can review additional risk factors considered in other jurisdictions, such as explicitly considering macroeconomic risk factors (inflation, interest rates, etc.), and energy/commodity price risk. One may argue that these risks are subsumed under existing risk categories. Major macroeconomic risk factors and energy price risk (which LEI views as "affordability risk") ultimately relate to regulatory risk, i.e., the availability of appropriate regulatory mechanisms to mitigate such risks. Examples include the composition of the I factor to mitigate inflation risk, allowed ROE/DLTDR to mitigate interest rate risk, and variance accounts to mitigate the energy price volatility risk.

With respect to alternate ways of how to consider risk factors, the OEB may adopt one of the three options below:

1. **Status quo:** As described in Section 4.2.1, the OEB currently undertakes a full reassessment of a utility's capital structure in the event of significant changes in the company's business and/or financial risk.
2. **Consider the risk factors at defined intervals (for adjusting the capital structure):** The OEB can set a pre-defined interval (e.g., 1, 3 or 5 years) to assess material changes in business and financial risks and determine their impacts (if any) on the capital structure allowed to utilities.
3. **Consider the risk factors at defined intervals (for adjusting the ROE):** Alternatively, **t**he OEB can set a pre-defined interval (e.g., 1, 3, or 5 years) to assess material changes in business and financial risks and consider the impacts (if any) as an additional component in the ROE formula that adds to/subtracts from the ROE. However, this would also entail moving away from determining a single uniform ROE for all utilities.

4.2.4 Recommendations

The major risk factors considered in other jurisdictions are similar to the ones considered in OEB proceedings. They can be grouped under the risk factors assessed by the OEB in recent equity thickness applications. LEI believes that the review of existing risk factors listed in Section 4.2.1, considering the current and forecasted macroeconomic conditions, are sufficient to determine the cost of capital parameters and capital structure (however, LEI believes that energy transition risk is primarily a policy risk and may be grouped as such). The key business risk factors include volumetric risk, operational risk, regulatory risk and policy risk (including energy transition risk). Financial risk assessment may be focused on the utility's ability to continue attracting debt and equity financing at reasonable terms, primarily relying on assessing key credit metrics and their potential impact on credit ratings (based on scenario analysis modelling for future utility cash flows). Financial risk assessment also includes the utility's debt servicing ability, as well as financial integrity. The key credit metrics that the OEB can consider are described in Figure 14.

Furthermore, as the OEB highlights in its capital structure policy, most risk factors tend to be stable over time. As such, considering their impacts at pre-defined intervals (as described in

Section 4.2.3) is inefficient and unnecessary. LEI recommends that the OEB's current policy (reviewing business/financial risk factors if there is a significant change from the status quo) be retained. Furthermore, LEI believes that adjusting the allowed /deemed equity thickness remains the appropriate lever to address material changes in the utility risk profile. The utility (or participants) may request a change in equity thickness in the rebasing application. If there is an application to review the change in risks by the utility or the intervenors, LEI recommends that the OEB review the change in business risks (volumetric risk, operational risk, regulatory risk and policy risk including energy transition risk) and financial risks (whether there is a change in the ability of the utility to continue to attract debt and equity financing at reasonable terms). However, this should not preclude the utilities from highlighting additional risk categories in their rate applications if they consider them to be material in nature.

LEI's recommendation to retain the status quo is consistent with the principles outlined by LEI in Section 3.1 as it meets the FRS by factoring the risk factors that may materially impact future utility cash flows, it is simple to administer as a complete review of business/financial risks is required only when the change in risk profile is perceived to be significant, and provides confidence to all stakeholders regarding the durability of the methodology by continuing with the status quo.

LEI recommendations - Issue 2

- The risk factors considered in recent equity thickness proceedings are sufficient.
    - Business risk assessment can be performed based on changes in volumetric risk, operational risk, regulatory risk and policy risk (including energy transition risk).
    - The assessment of financial risks can focus on the utility's ability to continue attracting debt and equity financing at reasonable terms, primarily relying on assessing key credit metrics and their potential impact on credit ratings.
- The current policy of considering the impact of risk factors when there is a significant change in business/financial risks is a reasonable approach, which LEI recommends be retained.

4.3 General issues – key regulatory and rate-setting mechanisms impacting utility risk

Issue 3: ***What regulatory and rate-setting mechanisms impact utility risk, and how should these impacts be considered*** in determining the cost of capital parameters and capital structure?

In the preceding section, as part of the business risk assessment, LEI classified ***regulatory risks,*** i.e., potential impacts of the regulator's policies and decisions on the utility's cash flows. LEI recommended that the OEB retain its existing policy of reviewing business/financial risks (which includes regulatory risks) if there is a significant change or upon application by the utility or the intervenors.

II. EXECUTIVE SUMMARY

A. Introduction

On March 28, 2024, the OEB initiated a generic proceeding in EB-2024-0063 to consider the methodology for determining the values of the cost of capital parameters and deemed capital structure to be used to set rates for electricity transmitters, electricity distributors, natural gas utilities, and OPG. The OEB indicated that it will determine whether its current approach to setting the cost of capital parameters and deemed capital structures continues to remain appropriate, and if not, what approach should be used. In addition, as noted in the Notice of Hearing, this proceeding will also consider the methodology for determining the OEB's prescribed interest rates. Also in scope for this proceeding is the question of what type of interest rate, if any, should apply to the generic Cloud Computing Deferral Account. On June 21, 2024, LEI, engaged by OEB Staff, provided its expert report. In the report LEI reviews and provides recommendations for each issue identified on the Issues List[1] in this proceeding, which includes the following categories:

1) General Issues;
2) Short-term debt rate;
3) Long-term debt rate and transaction costs;
4) Return on Equity;
5) Capital Structure;
6) Mechanics of Implementation; and
7) Other Issues.

The Board is investigating these issues at an important time that reflects an inflection point experienced by segments of the regulated utility industry. At an accelerating pace over the last decade, the global energy sector has embarked on a broad-scale transformation, referred to generally as the "Energy Transition," from a primary reliance on fossil fuels to an increased emphasis on more non-emitting and decentralized fuel sources.[2] This Energy Transition, coupled with other factors such as the growth in data centers to serve the world's increasing computing needs, is causing

1 Ontario Energy Board, EB-2024-0063, Schedule A, Approved Issues List, April 22, 2024.
2 S&P Global, "What is Energy Transition," February 24, 2020, https://www.spglobal.com/en/researchinsights/market-insights/what-is-energy-transition

substantial changes for utilities, particularly in their capital investment plans. As noted by DBRS Morningstar in a recent report on the North American utilities sector:

> *The industry's ongoing allocation of substantial capital toward initiatives such as climate adaptation, modernization, and energy transition has reached unprecedented levels, with many utilities rolling out capital expenditure (capex) programs that are 10% to 20% greater compared with previous cycles… We anticipate the trend of elevated capex and reliance on debt financing will likely persist over the longer term.*[3]

Electric distributors and transmitters are building new infrastructure to meet electricity demand that some utility executives expect to triple by 2050.[4] OPG is engaging in long-term refurbishment projects for its nuclear plants with a high degree of execution risk, while also investing in first-of-a-kind new nuclear technologies. Enbridge Gas must continue to invest in its system to provide safe and reliable natural gas service while also navigating through increasing complexities for gas distributors brought on by the Energy Transition.

These "unprecedented levels" of required capital investment being deployed over long-tenured construction projects necessitate access to capital in an increasingly competitive and integrated investment market, emphasizing the importance of reassessing the OEB authorized cost of capital for Ontario utilities to ensure Ontario ROEs and equity ratios meet the Fair Return Standard (also referred to herein as the "FRS").

This importance is also accentuated by shifts in investors' perceptions of risk for the utility industry, as measured by betas, which, as discussed in our section on the CAPM, represent the risk of individual securities relative to the market. Utility betas have increased substantially for electric and gas utilities since January 2020, and since the OEB last considered this issue in 2009. This indicates that regulated utilities are seen as increasingly risky by investors. Utility betas have been in the range of 0.80 to 0.90 percent since early 2020, as compared to the historical average level of 0.60 to 0.70 in the preceding 10 years, notwithstanding the increase observed in 2009 in the wake of the Great Recession. This shift in utility risk is not reflected in the present Ontario formula, which highlights the importance of periodic reviews of the formula to ensure that it continues to produce a fair return.

3 DBRS Morningstar, "Losing Steam: Weakening Credit Metrics in the North American Utilities Sector," May 15, 2024.

4 S&P Global, "Utility execs prepare for 'tripling' of electricity demand by 2050," April 19, 2023.

Another gating factor in this review is the recognition that Ontario's economy and regulated utilities operate in a North American market, requiring a similar perspective on the cost of capital. This Board took important steps in 2009 in recognition of this trend. Concentric's recommendations fall short of parity between Ontario and U.S. utilities, but would advance the ability of Ontario's utilities to compete for investment capital on a comparable basis with their North American peers. Ultimately, a fair return facilitates the necessary investments in Ontario to meet the complex needs of its consumers, and progress toward environmental and economic priorities.

With these factors in mind, Concentric's analysis in response to the Issues List incorporates market data from multiple industry segments across North America and several analytical models. We have also reviewed LEI's analysis and findings, and, while we agree with certain elements of LEI's report, we also disagree in certain fundamental areas, and we discuss those areas herein.

B. Overview of Concentric Recommendations

In response to questions raised by the Board in its Issues List, Concentric recommends rebasing the authorized ROE for Ontario's utilities based on current market conditions, as well as certain modifications to the parameters of the existing ROE formula. We also recommend changes to the deemed equity ratios for Ontario's utilities based on an analysis of business risk and a comparison to the equity ratios of comparable North American utilities. Concentric also addresses how often the OEB should review whether the formula is producing a return that satisfies the Fair Return Standard, what factors might cause the Board to review or suspend the formula, and the mechanics of updating the ROE formula. Our report also reviews and provides recommendations regarding the cost of short-term and long-term debt, as well as prescribed interest rates for DVAs, the appropriate cost of capital for CWIP accruals, and appropriate carrying charges for the Cloud Computing Deferral Account.

C. The Base ROE

This is the Board's first full proceeding to review the formula since it issued its Report of the Board on the Cost of Capital for Ontario Regulated Utilities (EB-2009-0084) ("2009 Report") on December 11, 2009. In that decision, the OEB set the base ROE at 9.75 percent for Ontario's electric and gas utilities and made certain modifications to the formula in response to concerns that the formula was not producing a return that satisfied the Fair Return Standard.

The allowed ROE for Ontario utilities must meet the Fair Return Standard, regardless of how it is set. Concentric's view is that the most reliable way to estimate an ROE that meets the Fair Return Standard is a full analysis using updated market data in conventional cost of capital models. Once rebased, it remains possible to continue using an ROE formula to reflect changes in capital markets between rebasing intervals.

D. Approach to Estimating Base ROE

An assessment of the appropriate return for Ontario's utilities relies on the fundamental legal and regulatory principle that a utility must have a reasonable opportunity to earn a fair return on its invested capital. The following three standards determine whether a return is fair:

- the comparable investment standard;
- the financial integrity standard; and
- the capital attraction standard.[5]

These standards must be met individually and collectively to satisfy the Fair Return Standard, and none ranks as more important than another.

Our analysis utilizes a traditional evidentiary approach based on current market data and well-established models. In this way, the Board can be assured that the ROE established in this proceeding meets the Fair Return Standard.

Concentric's ROE analysis includes six proxy groups: a Canadian group, a U.S. Electric group, a North American Electric group, a U.S. Gas group, a North American Gas group, and a North American Combined group. The subgroups are intended to evaluate whether there are meaningful differences between electric and gas utilities with respect to business and financial risks and their estimated ROEs. We have estimated the ROE using three commonly employed models: the DCF model, both constant growth and multi-stage forms; the CAPM; and the Risk Premium approach, with alternative inputs and model specifications designed to test the reasonable range of results.

The results of the alternative models are summarized in Figure 1. Because the utilities in the North American proxy groups are most representative of Ontario's utilities, we place more weight on those

[5] The OEB has accepted these standards. See, for example, the 2009 Report, p. 18.

results. While Concentric estimated the return on equity under various analytical approaches, we have narrowed the results to three models (i.e., the Multi-Stage DCF, the historical CAPM, and the Risk Premium approach) to develop our ROE rebasing recommendation in this proceeding. Those models provide a conservative (lower) estimate for Ontario utility ROEs relative to other models and are consistent with models that have been relied on in other jurisdictions evaluating a generic cost of capital to be applied across industry segments. Those models' results range from 9.7 percent to 10.3 percent, depending on the proxy group. It is important to emphasize that these results are based on conservative model inputs and, therefore, represent the lowest reasonable estimate of the required return for Ontario's electric and gas utilities as a whole.

Figure 1: Summary of ROE Results[6]

	CANADIAN PROXY GROUP	U.S. ELECTRIC PROXY GROUP	U.S. GAS PROXY GROUP	NORTH AMERICAN ELECTRIC PROXY GROUP	NORTH AMERICAN GAS PROXY GROUP	NORTH AMERICAN COMBINED
MULTI-STAGE DCF	10.38%	9.87%	9.60%	9.83%	10.21%	9.95%
CAPM – HISTORICAL MRP	9.36%	10.62%	10.00%	10.23%	9.89%	10.22%
RISK PREMIUM	9.44%	10.36%	10.30%	9.90%	9.87%	10.03%
AVERAGE	**9.7%**	**10.3%**	**10.0%**	**10.0%**	**10.0%**	**10.1%**

We also present a risk assessment of Ontario's utilities in relation to the proxy group companies for purposes of determining the appropriate deemed equity ratios for Ontario's utilities. Lastly, we assess whether our recommendations meet all three prongs of the Fair Return Standard.

Based on these results, we conclude that the current formula return of 9.21 percent in Ontario has diverged from a fair return for comparable risk companies, and changes to the authorized ROE and the deemed equity ratios for Ontario's utilities are required to meet the Fair Return Standard.

6 The DCF and CAPM results include an adjustment of 50 basis points for flotation costs and financial flexibility.

E. Cost of Capital Recommendations

Our recommendations are based on a cost of capital analysis utilizing the aforementioned models and a combination of Canadian, U.S., and North American proxy groups. We have also considered Ontario's regulatory precedents and the foundational regulatory principles that guide the OEB on these matters. This broader analysis is then applied to Enbridge Gas, the CLD, OPG, and Upper Canada Transmission 2, Inc. with specific consideration of the business and financial risks of Ontario's utilities in relation to the proxy companies. Based on the foregoing, we recommend the following:

1. An authorized base ROE of **10.0** percent, up from the base ROE of 9.75 percent in the current OEB formula and up from the current ROE of 9.21 percent resulting from the formula. This ROE recommendation is based on the average results of the multi-stage DCF model, the CAPM using a historical market risk premium for the North American combined proxy group, and the Risk Premium model, which is the most conservative (lower) estimate of the required return. We further recommend that LEI's proposed 8.95 percent base ROE not be accepted by the Board. An 8.95 percent authorized ROE would be in the bottom decile of authorized ROEs among Canadian and U.S. utilities and would not satisfy the Fair Return Standard.

2. As discussed herein, OPG faces a different and heightened level of risk compared to distributors and transmitters. In addition, the OEB has previously found that there is a heightened risk of nuclear generation relative to hydroelectric generation,[7] which is important to consider as OPG embarks on first-of-a-kind nuclear projects in addition to refurbishing its existing nuclear units. As such, the base ROE recommendation of 10.0 percent understates the ROE needed to meet the Fair Return Standard for OPG. There are also no direct comparators in the proxy groups analyzed by Concentric for OPG's pure-play rate-regulated generation operations. Rather than set alternative generic ROEs in the proceeding, however, Concentric recommends that should OPG bring forward a proposal and evidence in its payment amounts application regarding whether and what amount of additional risk premium should be applied to its authorized ROE, the OEB consider that proposal at its discretion as part of that proceeding.[8]

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[7] See, e.g., EB-2016-0152, Decision and Order, December 28, 2017, p. 102.

[8] Consistent with the OEB's finding in EB-2009-0084 Report of the Board, p. 13.

3. With regard to equity thickness, Concentric's primary finding within the context of this generic cost of capital proceeding is that Ontario equity ratios across all industry segments are lower than North American industry peers and fail to meet the comparable return standard component of the Fair Return Standard. While we continue to support the use of equity thickness to distinguish risk profiles among Ontario utilities, we have not recommended individual changes to each utility's equity thickness. Rather, we recommend that the deemed equity ratio be set at a minimum of 45.0 percent for *all* Ontario utilities, but that each utility have the option to retain its current equity ratio and/or propose differences from the "generic" equity thickness in its rates application. Concentric's recommendation of a minimum equity thickness of 45.0 percent reflects approximately the midpoint between the current deemed equity ratios in Ontario, which are generally consistent with the Canadian average deemed equity ratio for investor-owned utilities (see Figure 27), and the authorized equity ratios for U.S. electric and gas utilities. With respect to OPG, Concentric finds that its business risk is higher than the presented proxy group due to OPG's generation-only operations and recommends that the OEB accordingly determine an appropriate increase to the equity ratio in the company's next payment amounts proceeding.
4. Alternatively, if the OEB maintains the current deemed equity ratios of 38.0 percent for Enbridge Gas and 40.0 percent for Ontario's electric transmission and distribution utilities, then we recommend adjusting the authorized generic ROE for differences in financial leverage between the Ontario utilities and the proxy group companies. This would result in an upward adjustment of 138 to 163 basis points to our 10.0 percent ROE recommendation, based on the North American Electric, North American Gas and North American Combined proxy groups and the CAPM analysis using a historical market risk premium.
5. These recommendations meet the requirements of the Fair Return Standard and stand-alone principles the Board has embraced in the past and should provide sufficient financial support for the services provided by Ontario's utilities for the benefit of the province's energy consumers.

The current Ontario formula return of 9.21 percent is lower than the average, and lower than any of the results from the financial models and is not representative of the capital market environment and required returns for Ontario's utilities. Further, while the current deemed equity ratios for electric utilities in Ontario are near the Canadian average, and the deemed equity ratio for gas distribution is below the Canadian average, both electric and gas equity ratios in Ontario are well below their U.S. peers. Under the comparable return standard, both the authorized ROE and the deemed equity ratio for regulated utilities must be comparable to the returns available to investors in entities with similar risk. Equity investors and credit rating agencies consider authorized returns and deemed equity ratios as relevant benchmarks against which to measure whether the return in Ontario is comparable, on a risk-adjusted basis, to the returns in other jurisdictions across North America. On this basis, there is a gap that places Ontario's utilities at a comparative disadvantage when it comes to attracting capital. This gap has existed for many years but is now exposed by the increased integration of North American (and global) capital markets and utilities industries combined with increased demand for capital through the Energy Transition and will eventually harm Ontario's consumers as investment capital migrates to other uses or jurisdictions providing superior returns.

F. ROE Formula Recommendations

As discussed above, the most reliable method for determining required investor returns is a full presentation of refreshed market data and models used to estimate required returns (i.e., DCF, CAPM, Risk Premium). In addition, Concentric recommends minor modifications to the existing Ontario formula itself. From our examination, the Ontario ROE formula has generally resulted in ROEs that are in line with authorized returns for other Canadian electric and gas utilities but lower than the average authorized returns for comparable risk U.S. peers, and tend to further deviate from those required by the Fair Return Standard during periods of extreme stress in financial markets such as 2008-2009 and 2020-2021. Any formula-based approach must incorporate safeguards to ensure the formula-based ROE meets the Fair Return Standard, which requires suspending or rebasing the formula when it does not. In this case, it is critically important that the OEB take this opportunity to reset the base ROE to reflect current market data, thereby improving the probability that subsequent returns under a formula will remain within a reasonable range.

G. Implementation Issues

Periodic rate hearings remain the only reliable method for determination of utility ROEs that remain consistent with the Fair Return Standard. Understanding this limitation, Concentric recommends the Board take several steps to limit the potential impacts of deviations between the formula ROE, deemed capital structures and a fair return. Concentric recommends the OEB track and compare the following key utility and broader macroeconomic parameters on an annual basis:

- Authorized ROEs and equity ratios in other Canadian jurisdictions (individually) and the U.S. by industry segment (electric, gas) as reported by Regulatory Research Associates ("RRA")
- 10 and 30-year Treasury Bond Yields (Canada and the U.S.)
- A- and BBB-Rated Utility Bond Yields (Canada and the U.S.)
- Betas for the North American Proxy Group as defined in Section V
- Credit ratings from each agency covering Ontario's rate-regulated utilities.

Concentric recommends credit rating monitoring in order to provide some protection from insufficient earnings and credit quality, and a continuation of the 300 basis point trigger mechanism policy for all rate-regulated utilities, in conjunction with earnings-sharing mechanisms, to provide protection from excessive earnings.

Consistent with Concentric's recommended changes to the formula inputs, we recommend a continuation of annual updates to the OEB's cost of capital parameters in October, using data as of September 30th, except where forecasts are utilized. Concentric generally recommends trailing 90-day averages where historic data are utilized to avoid the inherent volatility in a single month's data.

Concentric recommends periodic cost of capital reviews with refreshed market data on ROE and capital structure every five years. Taken together, these steps provide a reasonable balance between the regulatory efficiency of a formulaic based approach and the requirements of meeting the Fair Return Standard.

Concentric believes it would be appropriate for changes in the cost of capital parameters and/or capital structure arising from this proceeding to be implemented in the next rate year, including for utilities in an approved rate term, subject to any settlement agreements and each utility submitting a compliance filing demonstrating how the change will be implemented within the context of its specific IR plan (e.g., Custom IR or I-X plan). All other elements and incentives of existing rate plans would remain in effect.

H. Other Issues

Concentric's report also provides findings and recommendations on the other issues included in the Issues List, including on the costs of debt and carrying costs on DVAs, CWIP, and the Cloud Computing Deferral Account. Specifically, Concentric's view is that the approach to determining the appropriate carrying costs to apply to DVAs and CWIP be based on regulatory and corporate finance principles. The application of the weighted average cost of capital ("WACC") to both DVAs and CWIP is most consistent with those principles, and, as such, Concentric recommends the WACC be used to calculate carrying costs on DVAs and CWIP. However, understanding the Board's historical preference to apply a short-term interest rate to DVAs, Concentric recommends that for DVAs that are to be cleared within one year, the short-term prescribed interest rate continue to apply.

As noted previously, Concentric also responds herein to LEI's report.

III. LEGAL REQUIREMENTS AND REGULATORY PRECEDENTS

The principles surrounding the concept of a "fair return" for a regulated company were established by the Supreme Court of Canada in the *Northwestern Utilities v. City of Edmonton* (1929) ("Northwestern") case, where the Supreme Court found:

> *By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.*[9]

More recently, the Supreme Court of Canada in *Ontario (Energy Board) v. Ontario Power Generation Inc.* confirmed *Northwestern*, stating:

> *This means that the utility must, over the long run, be given the opportunity to recover, through the rates it is permitted to charge, its operating and capital costs ("capital costs" in this sense refers to all costs associated with the utility's invested capital). This case is concerned primarily with operating costs. If recovery of operating costs is not permitted, the utility will not earn its cost of capital, which represents the amount investors require by way of a return on their investment in order to justify an investment in the utility. The required return is one that is equivalent to what they could earn from an investment of comparable risk. Over the long run, unless a regulated utility is allowed to earn its cost of capital, further investment will be discouraged and it will be unable to expand its operations or even maintain existing ones. This will harm not only its shareholders, but also its customers.*[10]

The law regarding fair return for utility cost of capital in the United States has evolved similarly. The U.S. Supreme Court set out guidance in the bellwether cases of *Bluefield Water Works* and *Hope Natural Gas Co.* as to the legal criteria for setting a fair return. In *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia*[11], the Court recognized that a rate of return may become unreasonable due to changing market conditions:

> *The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be*

9 Northwestern, p. 193.
10 Ontario (Energy Board) v. Ontario Power Generation Inc. 2015 SCC 44 at para 16.
11 (262 U.S. 679, 693 (1923)).

V. ESTIMATING THE COST OF EQUITY

A. Overview

In **Issue #10**, the Board asks what methodology the OEB should use to produce a return on equity that satisfies the Fair Return Standard. In December 2009, the Board modified the existing ROE formula, which is based on an ERP approach, to adjust the authorized ROE annually depending on changes in both government bond yields and the utility credit spread. The reason for including the utility credit spread was to address concerns that the previous formula was not producing a fair return in part because it did not consider utility specific risk, which is not captured in GOC bond yields.

To address this question, Concentric performed analyses of macroeconomic and proxy company market data using several reliable approaches to estimating ROE based on models relied on across North American jurisdictions. Concentric also responds to LEI's ROE analyses and recommendations.

As discussed in more detail in Section VI of our Report, based on Concentric's analysis, we find that the OEB's ROE formula currently is not producing an authorized ROE that meets the Fair Return Standard. For that reason, our recommendation is that the Board re-set the authorized base ROE to 10.0 percent, based on the results of the DCF, CAPM and Risk Premium models described in this section. Further, and as previously found by the Board, OPG faces a different and heightened level of risk compared to distributors and transmitters. As such, the base ROE recommendation of 10.0 percent understates the ROE for OPG. In addition, the OEB has previously found that there is a heightened risk of nuclear generation relative to hydroelectric generation,[51] which is important to consider as OPG embarks on first-of-a-kind nuclear projects in addition to refurbishing its existing nuclear units. There are also no direct comparators in the proxy groups analyzed by Concentric for OPG's pure-play rate-regulated generation operations. Rather than set alternative generic ROEs in the proceeding, however, Concentric recommends that should OPG bring forward a proposal and evidence in its payment amounts application regarding whether and what amount of additional risk premium should be applied as part of its authorized ROE, the OEB consider that proposal at its discretion as part of that proceeding. Lastly, the Board should adopt a process whereby the ROE

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51 See, e.g., EB-2016-0152, Decision and Order, December 28, 2017, p. 102.

formula is reviewed against the results of generally-accepted financial models at least every five years to ensure that the return satisfies the legal requirements of the Fair Return Standard.

B. Overview of Economic and Capital Market Conditions

Utilities raise debt and equity in a global market influenced by macroeconomic fundamentals, capital markets and central bank policies. The cost of debt for utilities is generally observable, but the cost of equity must be estimated with an informed view of the macroeconomic and capital market factors that impact the analysis.

Error! Reference source not found. Figure 3 below provides a comparison of key economic and market indicators, including betas (both raw and adjusted) in November 2009 (immediately prior to the Board's 2009 Report) to those in May 2024 (when our analysis in this proceeding was performed.)

Figure 3: Comparison of Interest Rates, Inflation, and Other Market Indicators

Indicator	November 2009	May 2024
Bank of Canada Overnight Rate	0.25%	4.75%
10-year Government of Canada bond	3.40%	3.64%
30-year Government of Canada bond	3.94%	3.51%
A-rated Canadian utility bond	5.41%	4.86%
GDP Growth Forecast – Consensus Economics – Canada	4.44%	3.84%
Consumer Price Inflation – Canada	1.0%	2.7%
U.S. Federal Reserve – Fed Funds Rate	0.0-0.25%	5.25-5.50%
10-year U.S. Treasury bond	3.40%	4.48%
30-year U.S. Treasury bond	4.31%	4.62%
Moody's A-rated utility bond	5.63%	5.74%
GDP Growth Forecast – Consensus Economics – U.S.	5.06%	4.04%
Consumer Price Inflation – U.S.	1.8%	3.3%
5-year Bloomberg Beta (raw)[52]	0.64	0.82
5-year Bloomberg Beta (adjusted)[53]	0.76	0.88

As shown in the above Figure, while interest rates on 30-year Canadian government and utility bonds have declined since November 2009, most other market indicators have increased. Specifically, monetary policy in both Canada and the U.S. is significantly more restrictive in May 2024 in response to higher inflation as compared to November 2009, when central banks were seeking to stimulate the global economy following the financial crisis. Importantly, utility betas (both raw and adjusted) have increased since November 2009 – a key measure of the market's view of utility risk. Overall, these market indicators support our recommendation to reset the base authorized ROE for Ontario's electric and gas utilities at 10.0 percent.

[52,54] Concentric took an average of the 5-year raw and adjusted Bloomberg Betas for the North American Proxy Group using the two time periods observed in Figure 3.

C. Selection of Proxy Companies

1. Proxy Group Selection

Because 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. Notwithstanding the care taken to ensure comparability, market expectations with respect to future risks and growth opportunities vary from company to company. Therefore, even within a group of similarly situated companies, it is common for analytical results to reflect a seemingly wide range. At issue, then, is how to select an ROE estimate in the context of that range. That determination must be based on an assessment of the company-specific risks relative to the proxy group and the use of informed judgment.

2. Proxy Group Screening

We developed six proxy groups for the ROE analysis to evaluate the results of multiple analytical approaches applied to different sectors and geographical groupings. In doing so, we note that OPG is unique as an electric generator. While several of the companies in our North American proxy group (described below) own regulated electric generation assets, they do not entirely capture the unique business and financial risks of OPG as a pure-play generator.

The first proxy group is comprised of publicly traded, regulated Canadian electric and natural gas utility companies. Recognizing there are few publicly traded companies in the utility sector in Canada, the only screening criterion was an investment grade credit rating, which all companies in the sector have. TC Energy (formerly TransCanada) has been excluded due to the risk profile of the TransCanada Mainline, which differs from gas distribution operations. Algonquin Power and Utilities Corp. was also excluded because the company did not have positive earnings growth rate forecasts from more than one source and announced a reduction of its dividend in January 2023.[54]

54 Having positive earnings growth rate projections from at least two sources and consistently paying quarterly cash dividends are necessary for inclusion in the DCF model.

Figure 4: Canadian Proxy Group

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

The second proxy group is comprised of like-risk U.S. electric utility companies. To obtain companies of comparable-risk, we performed a number of screens to determine a group of electric utilities with similar risk profiles to Ontario's electric utilities. We started with the 36 companies The Value Line Investment Survey ("Value Line") classifies as Electric Utility Companies. From that group, we further screened for companies that:

a) Have credit ratings of at least BBB+ from S&P Global or Baa1 from Moody's;

b) Consistently pay quarterly cash dividends with no reductions or eliminations in the past two years;

c) Have positive earnings growth rate projections from at least two sources;

d) Derived at least 70 percent of operating income from regulated operations in the period from 2021-2023;

e) Derived at least 80 percent of regulated operating income from electric utility service in the period from 2021-2023; and

f) Were not involved in a merger or other significant transformative transaction during the evaluation period.

The following U.S. electric utility companies meet our screening criteria:

Figure 5: U.S. Electric Proxy Group

Company	Ticker
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Duke Energy Corporation	DUK
Entergy Corporation	ETR
Eversource Energy	ES
Exelon Corp.	EXC
Evergy, Inc.	EVRG
NextEra Energy Corp	NEE
OGE Energy Corporation	OGE
Pinnacle West Capital Corp	PNW
Portland General Electric Company	POR
PPL Corporation	PPL
Southern Company	SO
Xcel Energy Inc.	XEL

The third proxy group is comprised of like-risk U.S. gas distributors. To obtain companies of comparable risk, we performed a number of screens to determine a group of gas utilities with similar risk profiles to Ontario's gas distribution utilities. Starting with the ten companies Value Line classifies as Natural Gas Distribution Companies, we further screened for companies that:

a) Have credit ratings of at least BBB+ from S&P Global or Baa1 from Moody's;

b) Consistently pay quarterly cash dividends with no reductions or eliminations in the past two years;

c) Have positive earnings growth rate projections from at least two sources;

d) Derived at least 65 percent of operating income from regulated operations in the period from 2021-2023;

e) Derived at least 90 percent of regulated operating income from natural gas distribution utility service in the period from 2021-2023; and

f) Were not involved in a merger or other significant transformative transaction during the evaluation period.

The following U.S. gas distribution companies meet our screening criteria:

Figure 6: U.S. Gas Proxy Group

Company	Ticker
Atmos Energy Corp	ATO
Northwest Natural Holding Company	NWN
ONE Gas, Inc.	OGS
Spire, Inc.	SR

In the current environment, gas and electric utilities face different risks, with gas distributors facing load risks from decarbonization, and electric utilities facing risks associated with the Energy Transition demand and associated capital needs, new requirements for electric transmission, and competition from distributed energy resources. This represents a shifting of relative risk profiles from prior periods, and the use of separate electric and gas proxy groups allows us to test the electric versus natural gas groups for any market-based differentials revealed in the results.

The fourth proxy group is a combined North American Electric proxy group that includes all Canadian and U.S. electric utility companies determined to be risk comparable to Ontario's electric utilities. As noted previously, OPG, as a generation-only utility, faces unique risks as compared to the electric proxy group, as the proxy companies that own generation also have lower risk transmission and distribution assets.

Figure 7: North American Electric Proxy Group

Company	Ticker
Canadian Utilities Limited	CU
Emera Corp.	EMA
Fortis, Inc.	FTS
Hydro One Ltd.	H
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Duke Energy Corporation	DUK
Entergy Corporation	ETR
Eversource Energy	ES
Exelon Corp.	EXC
Evergy, Inc.	EVRG
NextEra Energy Corp	NEE
OGE Energy Corporation	OGE
Pinnacle West Capital Corp	PNW
Portland General Electric Company	POR
PPL Corporation	PPL
Southern Company	SO
Xcel Energy Inc.	XEL

The fifth proxy group is a combined North American Gas proxy group that includes all Canadian and U.S. gas utility companies determined to be risk comparable to Ontario's gas distribution utilities.

Figure 8: North American Gas Proxy Group

Company	Ticker
AltaGas Ltd.	ALA
Canadian Utilities Limited	CU
Enbridge Inc.	ENB
Fortis Inc.	FTS
Atmos Energy Corp.	ATO
Northwest Natural Holding Company	NWN
ONE Gas, Inc.	OGS
Spire, Inc.	SR

Lastly, the sixth proxy group is a North American Combined proxy group that consists of all of the companies in the Canadian, U.S. Electric and U.S. Gas proxy groups. See Exhibit CEA-2 for our proxy group screening results.

3. Use of North American Proxy Groups

In its December 2009 Report, the OEB was among the first regulators in Canada to find that the use of U.S. companies and U.S. data to set the authorized returns for Canadian electric and gas utilities is appropriate. In support of this determination, the Board made a number of findings with regard to the proxy group that remain relevant today, including:[55]

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

> *Second, there was a general presumption held by participants representing ratepayer groups in the consultation that Canadian and U.S. utilities are not comparators, due to differences in the "time value of money, the risk value of money and the tax value of money." In other words, because of these differences, Canadian and U.S. utilities cannot be comparators. The Board disagrees and is of the view that they are indeed comparable, and that only an analytical framework in which to apply judgment and a system of weighting are needed. The analyses of Concentric Energy Advisors and Kathy McShane of Foster Associates Inc. are particularly relevant in this regard, and substantially advance the issue of establishing comparability to meet the requirements of the FRS.*

[55] Ontario Energy Board, EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, p. 21-23.

> *The Board notes that Concentric did not rely on the entire universe of U.S. utilities for its comparative analysis. Rather, Concentric carefully selected comparable companies based on a series of transparent financial metrics, and the Board is of the view that this approach has considerable merit... The use of a principled, analytical, and transparent approach to determine a low risk comparator group from a riskier universe for the purpose of informing the Board's judgment was supported by various participants in the consultation.*

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

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

In a 2016 proceeding involving OPG, however, the OEB noted that both Concentric (presenting information on behalf of OPG) and the Brattle Group (presenting information on behalf of the OEB Staff) should have made adjustments to the comparator group data "to account for the substantially lower common equity ratios allowed regulated utilities in Canada." [56] In considering this matter in this report, Concentric observes that allowed equity ratios for U.S. utilities generally remain higher than deemed equity ratios for Canadian utilities. However, this wide differential is not currently explained by differences in risk. Rather, Canada and the U.S. are both part of an integrated North American capital market where equity and debt investors do not perceive meaningful risk differentials between regulated utility investments in the two countries. This has been further supported more recently by regulators in British Columbia and Alberta.

Specifically, both the BCUC and the AUC have accepted the use of a North American proxy group comprised of utility companies in both Canada and the U.S. to set the authorized ROE for utilities

[56] Ontario Energy Board, Decision and Order EB-0216-0152, Ontario Power Generation Inc., December 28, 2017, p. 109.

under their jurisdiction. The BCUC explained its rationale for using a North American proxy group as follows:

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

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

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

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

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

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

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

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

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

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

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

Figure 9: Country Risk Ratings

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

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

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

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

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

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

D. Use of Multiple Methodologies to Estimate ROE

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

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

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

Regardless of which analyses are used to estimate the investor-required ROE, analysts must apply informed judgment to assess the reasonableness of the results and to determine the appropriate weighting to apply to the results under prevailing capital market conditions.

In the financial textbook, Financial Management Theory and Practice, Dr. Eugene F. Brigham explains the need to use multiple models to estimate the cost of equity as follows:

> *In practical work, it is often best to use all three methods – CAPM, bond yield plus risk premium, and DCF – and then apply judgment when the methods produce different results. People experienced in estimating equity capital costs recognize that both careful analysis and some very fine judgments are required.*[66]

The OEB specifically supported the use of multiple methodologies to estimate the equity risk premium in its 2009 Report, stating:

> *The Board agrees that the use of multiple tests to directly and indirectly estimate the ERP is a superior approach to informing its judgment than reliance on a single methodology. In particular, the Board is concerned that CAPM, as applied by Dr. Booth, does not adequately capture the inverse relationship between the ERP and the long Canada bond yield. As such, the Board does not accept the recommendation that it place overwhelming weight on a CAPM estimate in the determination of the initial ERP.* [67]

Other Canadian utility regulators, including the AUC[68] and the BCUC, have also recognized the benefits of using multiple methodologies to determine a fair ROE. In particular, the BCUC recently determined that it was appropriate to base the authorized ROE for FortisBC Energy Inc. (a gas distribution utility) and FortisBC Inc. (an electric utility) on an equal weighting of the Multi-Stage DCF model, the CAPM using an average market risk premium, and the U.S. Risk Premium analysis.[69] That is the same approach we have followed in this report.

We have considered the results of the DCF model (both constant growth and multi-stage forms), the CAPM, and the Risk Premium model to estimate the ROE for the various Canadian, U.S., and North

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66 Dr. Eugene F. Brigham, Financial Management Theory and Practice, Fourth Edition, copyright 1985, p. 256.

67 Ontario Energy Board, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, EB-2009-0084, p. 26.

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

69 British Columbia Utilities Commission, Generic Cost of Capital Proceeding (Stage 1), Decision and Order G-236-23, September 5, 2023, p. 136.

American comparator groups. We have also compared the results of our analyses to authorized returns for other regulated utilities in both Canada and the U.S. The following section of our report discusses the inputs and results of each model in more detail, starting with the DCF model.

E. Discounted Cash Flow ("DCF") Model

The premise underlying the DCF model is that investors value an investment according to the present value of its expected cash flows over time. The standard DCF model is shown in Equation [1]:

$$P = \frac{D_0(1+g)^1}{(1+r)^1} + \frac{D_1(1+g)^2}{(1+r)^2} + \cdots + \frac{D_{n-1}(1+g)^n}{(1+r)^n} \quad [1]$$

where:

P = the current stock price

g = the dividend growth rate

D_n = the dividend in year n

r = the cost of common equity.

Assuming a constant growth rate in dividends, the model is commonly simplified to compute the ROE, as shown in Equation [2]:

$$r = \frac{D}{P} + g \quad [2]$$

Stated differently, the cost of common equity is equal to the dividend yield plus the expected dividend growth rate.

The Constant Growth DCF model requires the following assumptions:

- a constant average growth rate for earnings and dividends;
- a stable dividend payout ratio;
- a constant price-to-earnings multiple; and
- a discount rate greater than the expected growth rate.

As discussed later in the report, other forms of the DCF model do not rely on the assumption of constant growth in perpetuity.

We discuss each of the DCF model variables in the subsections below.

1. Dividend Yield

As shown in equation [3], the dividend yield component of the DCF model is calculated as follows:

$$[3] \qquad Y = \frac{D_0(1+0.5g)^1}{P_0}$$

One half year's growth rate is applied to the annual dividend rate to account for increases in quarterly dividends at different times throughout the year. It is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. This adjustment ensures that the expected dividend yield is, on average, representative of the coming twelve-month period and does not overstate the aggregated dividends to be paid during that time.

The dividend yields were calculated for each company in the respective proxy groups by dividing the current annualized dividend by the average stock price for each company for the 90 trading days ended May 31, 2024. Those dividend yields are multiplied by one-half the growth rate to reflect expected future dividend increases.

2. Growth Rate Estimates

In considering the appropriate growth rate for the DCF model, the most relied upon indicator of investors' expectations is analysts' estimates of future earnings growth. We have relied on earnings growth estimates from S&P Capital IQ Pro (formerly SNL Financial), the Value Line, Zacks Investment Research ("Zacks"), and Thomson First Call (as reported on Yahoo! Finance) for the companies in the respective proxy groups. LEI has also relied on earnings per share growth rates from S&P Capital IQ in its DCF analysis. We rely on multiple sources to best inform the overall estimate of earnings growth for each company. Those growth rates are shown in Exhibit CEA-4.

Investors typically rely on projected earnings growth rates rather than other measures of growth such as dividend growth rates for several reasons. First, although the DCF model is based on dividend growth, a company's dividend growth is derived from and can only be sustained by earnings growth. Second, in order to reduce the long-term growth rate to a single measure, as required in the Constant Growth DCF model, it is necessary to assume a constant payout ratio, and that earnings per share, dividends per share and book value per share grow at a constant rate. Third, earnings growth rates are less influenced by dividend decisions that companies may make in response to near-term changes in the business environment. Finally, analysts' forecasts of earnings growth are widely available, whereas dividend and book value growth rates are generally available only from Value Line.[70]

Some intervenors and utility regulators in Canada have expressed concern that analysts' earnings growth rates may be overly optimistic, and LEI makes this assertion in its report in this proceeding. If optimism bias were present in analysts' earnings forecasts, it could create an upward bias in the estimated cost of capital that results from the DCF approach. To control for this concern, some analysts have used GDP growth as a proxy for long-term earnings growth. We, however, do not share the view that analysts' earnings growth rates are biased, as discussed below.

In order to assess whether analyst earnings growth rates are reasonable relative to GDP growth, we compared the actual earnings and dividends per share growth rates (for the companies in the four proxy groups for which the required data are available) to historical and projected GDP growth over the period from 2009-2023. These results are shown in the Figure 10 below.

Figure 10: Utility Earnings, Dividend and GDP Growth Comparisons

Proxy Group	[1] **Historical EPS Growth Rate, 2009-2023**	[2] **Historical DPS Growth Rate, 2009-2023**	[3] **Historical GDP Growth Rate, 2009-2023**	[4] **Forecast EPS Growth Rate, 2027-2029**	[5] **Forecast Nominal GDP Growth Rate, 2030-2034**
North American Electric Proxy Group	4.36%	5.44%	4.61%	6.00%	4.00%
North American Gas Proxy Group	5.81%	5.80%	4.55%	4.84%	3.94%
North American Combined Proxy Group	4.62%	5.44%	4.60%	5.98%	3.99%
Average	**4.93%**	**5.56%**	**4.59%**	**5.61%**	**3.98%**

Notes:
[1] - [2] Source: Value Line Reports, dated April 19, 2024, May 10, 2024, May 24, 2024, June 7, 2024, and June 14, 2024; median results
[3] Source: Federal Reserve Bank of St. Louis Economic Data for Canada and the U.S.
[4] Source: Zacks, SNL, Value Line, and First Call, as of May 31, 2024
[5] Source: Consensus Economics Inc., Consensus Forecasts, April 8, 2024, at 3 and 29; estimates for 2030-2034 = (GDP x (1+ CPI))+CPI

This analysis shows important relationships based on 15 years of history, which is a sufficient time-period to draw meaningful conclusions and to frame reasonable expectations for the future. These relationships are as follows:

70 Value Line is the only publication of which we are aware that projects dividend and book value growth rates. Those estimates represent the Value Line analyst's perspective on dividend and book value growth. In contrast, many of the earnings growth rates that are publicly available are consensus estimates with contributions provided by several analysts.

- Dividends track reasonably well with earnings growth, as would be expected, as earnings drive dividend growth. The average historical dividend growth rate for the three North American proxy groups of 5.56 percent exceeds the average historical earnings growth rate of 4.93 percent by 63 basis points. We conclude that earnings growth is a reasonable proxy for dividend growth, especially with a broad enough company sample.

- Both average earnings and average dividend growth for the three North American proxy groups exceeded actual GDP growth over the period. This is unsurprising, as earnings for utilities can, and do, exceed the growth of the overall economy. As evidenced by the data, there is no fundamental basis to assume that economy-wide GDP growth with a mix of macroeconomic, social and business drivers serves as a limit on utility earnings or dividend growth.

- Looking to the future, it is reasonable to rely on analyst projections, as Concentric and other experts commonly do, even if they exceed GDP growth. In fact, over the historical period, average dividend growth for the three North American proxy groups exceeded historical GDP growth by 97 basis points. Further, the average analyst earnings growth projection of 5.61 percent is reasonably close to the historical earnings growth rate of 4.93 percent.

These relationships indicate that the projected analyst growth rates are entirely reasonable by historical standards. Nevertheless, to address concerns about sole reliance on analysts' earnings growth rates, we relied on a multi-stage specification of the DCF model which trends the earnings growth down to forecast GDP growth. Further, our analysis included other ROE estimation techniques, including the CAPM and Risk Premium model. Those analyses are described below.

3. Multi-Stage DCF Model

In order to address some of the limiting assumptions underlying the Constant Growth form of the DCF model, we also considered the results of a multi-period (three-stage) DCF model where long-term earnings growth is limited to GDP growth. The Multi-stage DCF model tempers the assumption of constant growth in perpetuity with a three-stage approach based on near-term, transitional and long-term growth rates. The inherent conservatism of the Multi-stage DCF model is reinforced by the fact that utilities investing in Energy Transition will remain in a capital growth phase for a sustained period that is likely measured in decades.

The multi-stage DCF model transitions from near-term growth (i.e., the average of Value Line, Zacks, S&P Capital IQ Pro, and Thomson First Call forecasts used in the Constant Growth model) for the first stage (years 1-5) to the long-term forecast of nominal GDP growth for the third stage (year 11 and beyond). The second, or transitional, stage connects near-term growth with long-term growth by changing the growth rate each year on a pro rata basis. In the terminal stage, the dividend cash flow then grows in perpetuity at the same rate as nominal GDP. The following table provides the growth rates in each stage of the analysis for the North American Proxy Group as an example.

Figure 11: Multi-Stage DCF Growth Rates

	Stage 1 (Years 1-5)	**Interim Stage (Years 6-10, Average)**	**Stage 3 (Years 11+)**
North American Proxy Group	5.98%	4.99%	3.99%

The return on equity is the internal rate of return based on the current average stock price and this stream of dividend payments. As we have shown above, GDP growth is conservatively low based on the historical earnings and dividend growth of the proxy group companies.

Nominal GDP growth rates were developed using data for each country as reported by Consensus Economics, Inc. for the period from 2030-2034. These forecasts are based on real (constant dollar) growth rates and estimates for inflation. The inflation estimate was applied to the estimate of real GDP growth to develop the nominal (post-inflation) GDP growth rate. The estimates of nominal GDP growth are summarized in Figure 12.

Figure 12: Estimates of Nominal GDP Growth[71]

	Canada	U.S.
Real GDP Growth	1.8%	1.8%
Inflation	2.0%	2.2%
Nominal GDP Growth	**3.84%**	**4.04%**

4. DCF Results

The DCF results are summarized in Figure 13 and shown in Exhibits CEA-4 and CEA-5. While we show DCF results for both the Constant Growth and Multi-Stage forms of the DCF model, our ROE recommendation conservatively focuses on the results of the Multi-Stage DCF analysis.

Figure 13: 90-day Average DCF Results[72]

Proxy Group	Constant Growth	Multi-Stage
Canadian	11.06%	10.38%
U.S. Electric	11.30%	9.87%
U.S. Gas	10.34%	9.60%
North American Electric	11.00%	9.83%
North American Gas	10.91%	10.21%
North American Combined	11.09%	9.95%

We place more weight on the results of the North American proxy groups because the companies in those groups are more representative of Ontario's utilities than the Canadian proxy group companies,

71 Consensus Forecasts, for 2030-2034, April 8, 2024, p. 3 (U.S.) and 29 (Canada).
72 Results include an adjustment of 50 basis points for flotation costs and financial flexibility.

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

F. Capital Asset Pricing Model ("CAPM")

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

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

where:

Ke = the required ROE for a given security;

β = Beta of an individual security;

rf = the risk-free rate of return; and

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

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

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

where:

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

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

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

1. Risk Free Rate

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

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

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

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

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

73 Consensus Forecasts by Consensus Economics Inc., Survey Date April 8, 2024, p. 3 and 29.
74 Historical spreads were calculated using daily bond yields published on Bloomberg from June 2015 through May 2024.

projected interest rates we are using in the table below are slightly higher than recent yields in Canada and somewhat lower than recent yields in the U.S.

Figure 15: Risk Free Rate[75]

30-Year Risk Free Yield	**CDN**	**U.S.**
Apr. 2024 Consensus Forecast Average 2025-2027 Forecast 10-Year bond yield	3.13%	3.67%
Average Daily Spread between 10-year and 30-year government bonds (10-year average)	0.33%	0.47%
Average	**3.46%**	**4.14%**

The recent divergence between Canadian and U.S. interest rates has caused some concern among economists focusing on downward pressure on the value of the Canadian dollar. But recent developments indicating lower inflation and easing of central bank policies on both sides of the border have mitigated those concerns. Characterizing these developments, the *Financial Post* reported:

> *Interest rate divergence swept onto the economic radar in the spring as the U.S. economy steamed ahead of its northern counterpart and economists began to forecast that the Bank of Canada would have to cut interest rates many more times than the Fed.*
>
> *Economists worried the resulting chasm between the two benchmark lending rates would bring about dire consequences for the loonie, since lower rates would result in the Canadian currency dropping in value, forcing investors to turn elsewhere for a better return.*
>
> *….*
>
> *Now that inflation is apparently behaving, it could mean a narrower spread between the two central bank rates.*[76]

[75] Consensus Economics Inc., Survey Date April 8, 2024; and Bloomberg for daily bond yields. Differences are due to rounding.

[76] Posthaste: Economists breathe a bit easier over Canada, U.S. interest rate divergence and outlook for Loonie, *Financial Post*, July 17, 2024.

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

2. Beta

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

Figure 16: Value Line and Bloomberg Betas

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

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

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

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

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

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

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

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

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

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

[78] Roger A. Morin, *New Regulatory Finance*, p. 74.

[79] Regulated Utility Cost of Capital: Theory and Canadian Practice, Jonathan A. Lesser, Continental Economics, Inc., August 4, 2021, p. 42.

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

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

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

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

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

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

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

80 British Columbia Utilities Commission – Generic Cost of Capital – Project No. 1599176 – BCUC Staff Consultant Response, Dr. Lesser Responses to FortisBC Set 1, November 30, 2021, 10.1.
81 Responses to British Columbia Utilities Commission Information Request No. 2 Generic Cost of Capital Prepared by Jonathan Lesser, Ph.D., June 10, 2022, 7.1.
82 British Columbia Utilities Commission, Decision and Order G-236-23, September 5, 2023, p. 75.

3. Market Risk Premium ("MRP")

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

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

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

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

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

4. CAPM Results

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

Figure 18: CAPM ROE Results[83]

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

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

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

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

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

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

G. Flotation Costs and Financing Flexibility

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

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

The practice of allowing a 50 basis point adjustment for flotation costs and financing flexibility is widespread across Canada. As shown in Figure 20, of the ten jurisdictions examined, seven have historically granted the 50 basis point adjustment. Only Quebec deviates from 50 basis points by allowing 30 to 40 basis points, and Manitoba and Saskatchewan, which have only Crown utilities, do not employ regular ROE analyses. In Nova Scotia, the Board's February 2023 order approving a settlement agreement did not specify whether flotation costs were included in the authorized ROE for Nova Scotia Power. The BCUC recently rejected an ROE adjustment for flotation costs and financing flexibility for FortisBC Energy, Inc. and FortisBC Inc. in its September 2023 decision, although it made some adjustment in the equity ratio. In 2016, the BCUC accepted a 50 basis point adjustment for flotation and financing flexibility, but did not accept that the adjustment should automatically be applied to experts' analytical results. The AUC's October 2023 order in the GCOC proceeding for 2024 and beyond included an adjustment of 50 basis points.

Figure 20: Jurisdictional Comparison of Financing and Flexibility Adjustment

Jurisdiction	Adj.	Docket/Proceeding	Notes
Alberta	50 bps	2018 GCOC Decision 22570-D01-2018 and 2024 GCOC Decision 27084-D02-2023	Adjustment of 50 bps is normally included in the allowed return to account for administrative and equity issuance costs, any impact of underpricing a new issue, and the potential for dilution.
British Columbia	50 bps	2013 GCOC Decision Stage 1, and 2016 FEI Decision	Has previously approved 50 bps adjustment but cautioned that it should not be considered "automatic" and instead should be considered on a case-by-case basis. (see note above on most recent decision)
Manitoba	N/A	N/A	N/A
New Brunswick	50 bps	2010 EG Decision	Accepted 50 bps as being the lower of two proposed adjustments presented.
Newfoundland and Labrador	50 bps	P.U. 13(2013), and P.U. 18(2018)	Accepted 50 bps adjustment
Nova Scotia	N/A	2023 NSUARB 12	The 2023 Nova Scotia Power rate application was resolved through a settlement agreement that specified an authorized ROE but did not indicate whether that return included flotation costs and/or financing flexibility.
Ontario	50 bps	EB-2009-0084	Base ROE value included a 50 bps adjustment for flotation and financing flexibility.
Prince Edward Island	50 bps	Order UE19-08	Approved ROE included a 50 bps adjustment for flotation costs.
Saskatchewan	N/A	N/A	N/A
Quebec	30-40 bps	D-2011-182/R-3752-2011	Regie determined provision for flotation costs and other costs of accessing capital markets ranging from 30-40 bps, with a greater weighting at the lower end of the range.

For the above reasons, Concentric has adjusted the results of our DCF and CAPM analyses by 50 basis points for flotation costs and financing flexibility.

H. Risk Premium Analysis

In general terms, the Risk Premium approach recognizes that equity is riskier than debt because equity investors bear the residual risk associated with ownership. Equity investors, therefore, require a greater return (i.e., a premium) than would a bondholder. The Risk Premium approach estimates the ROE as the sum of the equity risk premium and the yield on a particular class of bonds.

$$ROE = RP + Y \qquad [6]$$

Where:

RP = Risk Premium (difference between allowed ROE and the 30-Year Treasury Yield) and

Y = Applicable bond yield.

Since the equity risk premium is not directly observable, it is typically estimated using a variety of approaches, some of which incorporate ex-ante, or forward-looking, estimates of the ROE and others that consider historical, or ex-post, estimates. For our Risk Premium analyses, we have relied on authorized returns from a large sample of U.S. electric utilities and U.S. gas distribution companies. In addition, we have conducted a Risk Premium analysis based on authorized returns for Canadian electric and gas utility companies since 2000.

To estimate the relationship between risk premia and interest rates, we conducted a regression analysis using the following equation:

$$RP = a + (b \times Y) \quad [7]$$

Where:

RP = Risk Premium (difference between allowed ROEs and the 30-Year Treasury Yield);

a = Intercept term;

b = Slope term; and

Y = 30-Year Treasury Yield.

Data regarding allowed ROEs were derived from over 900 electric utility company rate cases and over 750 gas distribution utility rate cases in the U.S. from January 1992 through May 31, 2024, as reported by Regulatory Research Associates.

Figure 21: Risk Premium Results – U.S. Electric

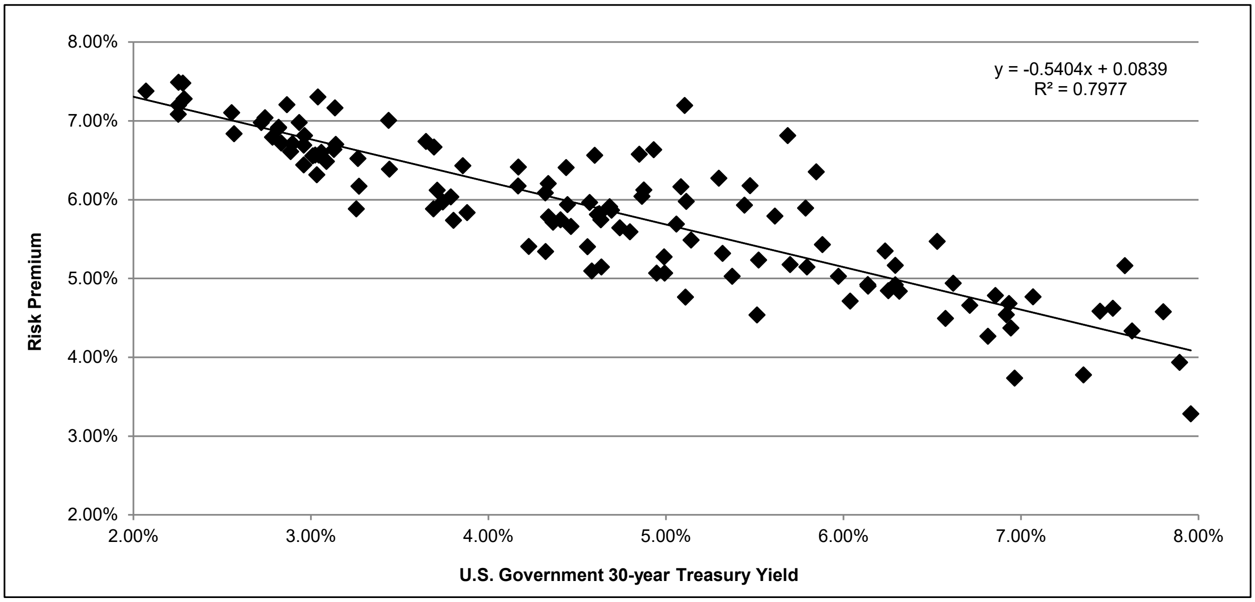
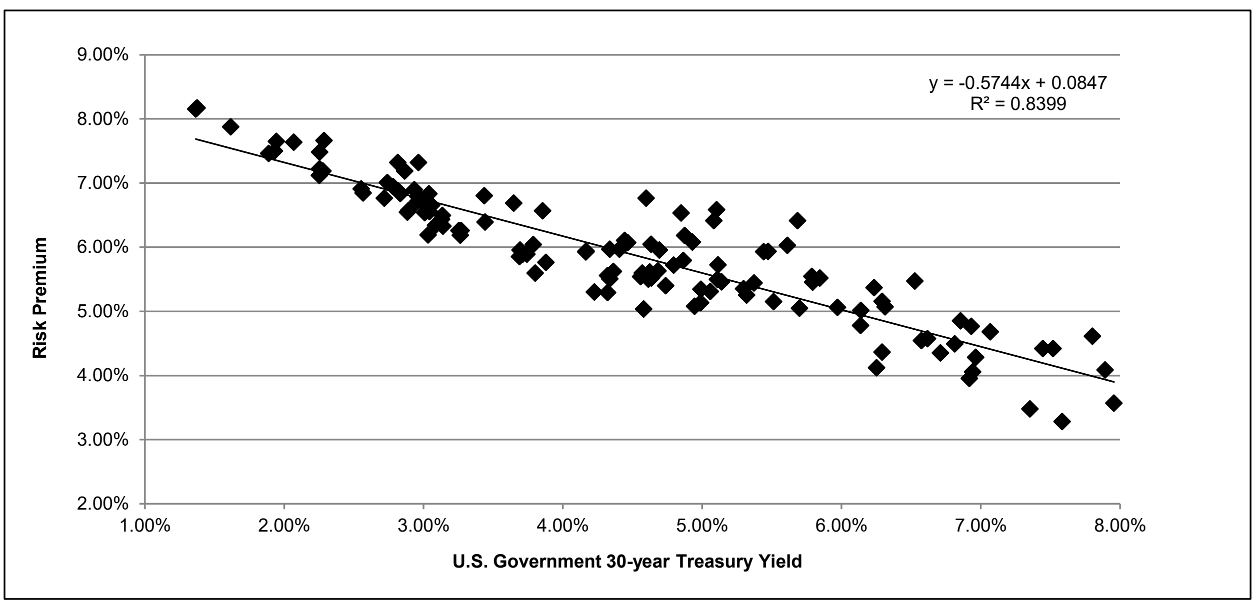


Figure 22: Risk Premium Results – U.S. Gas



As illustrated by Figure 2323 and Figure 24, the risk premium varies with the level of the bond yield, and generally increases as the bond yields decrease, and vice versa. In order to apply this relationship to current and expected bond yields, we consider three estimates of the 30-year U.S. Treasury yield: the current 30-day average, a near-term Blue Chip consensus forecast for Q3 2024 – Q3 2025, and a long-term Blue Chip consensus forecast for 2025–2029. We find this five-year result to be most applicable because investors typically have a multi-year view of their required returns on equity. Based on the regression coefficients in Exhibits CEA-8.1 and 8.2, which enable the estimation of the risk premium at varying bond yields, the results of our Risk Premium analysis are shown in Figure 23 and Figure 24.

Figure 23: Risk Premium Results – U.S. Electric

	Using 30-Day Average Yield on 30-Year Treasury Bond	**Using Q3 2024–Q3 2025 Forecast for Yield on 30-Year Treasury Bond[84]**	**Using 2025-2029 Forecast for Yield 30-Year Treasury Bond[85]**
Yield	4.66%	4.40%	4.30%
Risk Premium	5.87%	6.01%	6.06%
Resulting ROE	10.53%	10.41%	10.36%

84 Blue Chip Financial Forecasts, Vol. 43, No. 5, May 1, 2024, at 2. We typically prefer to use Blue Chip as our source for interest rates forecasts in the U.S. However, Blue Chip does not provide a long-term forecast for Canada, so the risk-free rate in our CAPM analysis uses bond yields from Consensus Economics.

85 Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023, p. 14.

Figure 24: Risk Premium Results – U.S. Gas

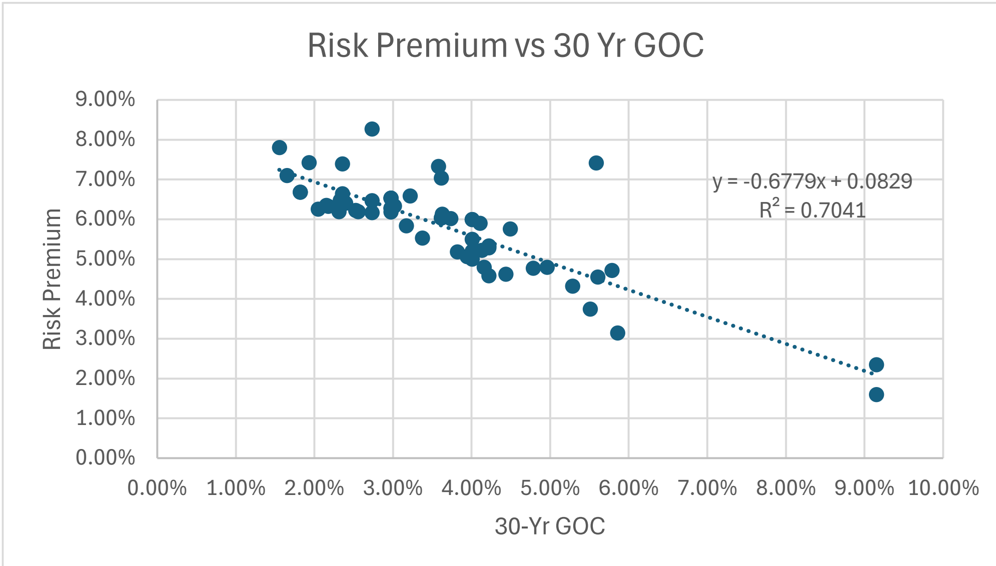
	Using 30-Day Average Yield on 30-Year Treasury Bond	Using Q3 2024–Q3 2025 Forecast for Yield on 30-Year Treasury Bond[86]	Using 2025-2029 Forecast for Yield 30-Year Treasury Bond[87]
Yield	4.66%	4.40%	4.30%
Risk Premium	5.79%	5.94%	6.00%
Resulting ROE	10.45%	10.34%	10.30%

We also conducted a risk premium analysis based on approximately 60 Canadian decisions for electric and gas utilities from 1994 through 2023. As in the U.S., the regression analysis for Canada shows an inverse relationship between interest rates and the equity risk premium. Figure 25 shows the regression equation produced by this analysis. See also Exhibit CEA-9 for the full risk premium analysis for Canada.

86 Blue Chip Financial Forecasts, Vol. 43, No. 5, May 1, 2024, p. 2. We typically prefer to use Blue Chip as our source for interest rates forecasts in the U.S. However, Blue Chip does not provide a long-term forecast for Canada, so the risk-free rate in our CAPM analysis uses bond yields from Consensus Economics.

87 Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023, p. 14.

Figure 25: Risk Premium Results - Canada[88]



The Canadian risk premium analysis shows that the average equity risk premium in Canada since 1994 has been 5.94 percent. By comparison, this represents a relatively modest increase from the risk premium determined by the OEB in the 2009 consultation of 5.5 percent.89 The results of the Canadian risk premium analysis, shown in Figure 26 below, support the reasonableness of our DCF and CAPM analyses for the North American proxy group companies.

88 The two ROE decisions shown on the far-right side of the chart are from 1994, when interest rates were significantly higher than they are today, and the resulting equity risk premium was significantly lower.

89 OEB Cost of Capital Report, 2009, p. 37.

Figure 26: Risk Premium Results - Canada

	Using 30-Day Average Yield on 30-Year GOC Bond[90]	Using 2025–2026 Forecast for Yield on 30-Year GOC Bond[91]	Using 2025-2029 Forecast for Yield 30-Year GOC Bond[92]
Yield	3.55%	3.46%	3.55%
Risk Premium	5.89%	5.95%	5.89%
Resulting ROE	9.44%	9.41%	9.44%

I. Comparison to Other Authorized ROEs

As shown in Figure 27 the authorized ROE for Canadian investor-owned electric utility companies currently ranges from 8.50 percent (Newfoundland Power) to 9.65 percent (FortisBC Inc.), with an average of 9.16 percent. The authorized ROE for Canadian investor-owned gas distribution companies currently ranges from 8.90 percent (Energir) to 10.65 percent (Eastward Energy), with an average of 9.23 percent. The average authorized return for electric utilities in the U.S. is 9.67 percent since January 2023 and the average for U.S. gas distributors is 9.65 percent.

90 Bloomberg Professional, as of May 31, 2024.
91 Consensus Economics, April 2024, p. 29. We used the same forecast of government bond yields as in our CAPM analysis. See Figure 15 of this report.
92 Consensus Economics, April 2024, p. 29.

Figure 27: Comparison of Northern American Authorized Equity Returns

Operating Utility	ROE	Equity Ratio
Ontario (current)	**9.21%**	**38.0% - 45.0%**
Alberta Electric utilities[93]	9.28%	37.0%
FortisBC Inc.	9.65%	41.0%
Maritime Electric	9.35%	40.0%
Newfoundland Power	8.50%	45.0%
Nova Scotia Power	9.00%	40.0%
Canadian Electric Avg	**9.16%**	**40.6%**
Canadian Electric Median	**9.28%**	**40.0%**
U.S. Electric Mean[94]	**9.67%**	**50.2%**
Apex Utilities	9.28%	39.0%
ATCO Gas	9.28%	37.0%
Energir, Inc.[95]	8.90%	38.5%
FortisBC Energy Inc.	9.65%	45.0%
Gazifere	9.05%	40.0%
Canadian Gas Avg	**9.23%**	**39.9%[96]**
Canadian Gas Median	**9.28%**	**39.0%**
U.S. Gas Mean[97]	**9.65%**	**52.1%**

As discussed in Section VI of our report, the Ontario utilities have significantly greater financial risk than many other electric and gas distribution companies, especially those in the U.S. In particular, the Ontario utilities have a more highly leveraged regulatory capital structure, which contains 40 percent common equity for electric distributors and transmitters, 38 percent for Enbridge Gas and 45 percent for OPG. These equity ratios are low by comparison to the U.S. companies in the North American proxy groups. In addition to resetting the ROE as proposed, if the OEB does not increase the deemed equity ratios of Ontario's electric and gas utilities, as we recommend, then it is

93 Alberta Electric utilities includes ATCO Electric, Fortis Alberta, ENMAX, and EPCOR.
94 Source: Regulatory Research Associates, decisions from January 1, 2023, through May 31, 2024.
95 Deemed capital structure for Energir, Inc. includes 6.5 percent preferred equity, so that debt ratio is 55 percent.
96 The OEB Decision and Order for Enbridge Gas in EB-2022-0200 dated December 21, 2023, stated on page 66 that Enbridge Gas's reply argument documented that the customer weighted average equity ratio used by LEI for the Canadian peer group would increase to 40.5% when updated to include the 45% deemed equity ratio for FEI approved by the BCUC in September 2023. Concentric has used a simple average in this table.
97 Ibid.

appropriate for the Board to approve a further increase in the ROE in order to compensate equity investors for the greater financial risk of the Ontario utilities. Otherwise, Ontario's electric and gas utilities are placed at a disadvantage in competing for capital with other companies of comparable risk.

For example, in September 2023, the BCUC issued a decision in the generic cost of capital proceeding for FortisBC Energy Inc. (FEI, a gas utility) and FortisBC Inc. (FBC, an electric utility) in which the authorized ROE was increased to 9.65 percent for both FEI and FBC, while the deemed equity ratio for FEI was raised from 38.5 percent to 45.0 percent and for FBC from 40.0 percent to 41.0 percent. FEI and FBC both operate under performance-based regulation ("PBR") plans with a four-year term, similar to most utilities in Ontario. The PBR plans for FEI and FBC include numerous deferral and variance accounts and regulatory mechanisms that reduce regulatory lag and facilitate timely recovery of operating and capital costs, much like the Custom IR plans in Ontario. FEI has a quarterly gas cost mechanism that adjusts rates for the variance between forecast and actual purchased gas costs. Given the similarities between FEI and FBC and the Ontario utilities from a business risk perspective, the maintenance of the current (or a lower) ROE and equity ratios (i.e., an authorized return of 9.21 percent on 38.0 or 40.0 percent deemed common equity) would fail to meet the comparable return standard given FEI's authorized ROE of 9.65 percent on 45.0 percent deemed common equity and FBC's authorized ROE of 9.65 percent on a 41.0 percent equity ratio. As discussed earlier, Ontario utilities are competing for capital with other North American utilities, and this competition will become even more accentuated in the Energy Transition, as utilities vie for limited investor capital.

LEI's Recommendation and Concentric's Response

LEI recommends resetting the base ROE in the OEB formula to 8.95 percent within a range from 8.23 percent to 10.22 percent, as discussed on pages 125-127 of LEI's report. LEI's recommendation is based solely on the results of its CAPM analysis and does not include an adjustment for flotation costs or financing flexibility, as explained on page 122 of LEI's report. LEI recommends considering the transaction costs associated with equity issuances as operating costs. As shown in Figure 41 of LEI's report, their CAPM analysis uses a risk-free rate of 3.19 percent, an average beta coefficient of 0.69, and a market risk premium ranging from 7.28 percent to 10.16 percent based on historical U.S. return data. LEI considers six alternative methods for setting the base ROE for Ontario's utilities, including Alternative #6, which takes an average of the DCF, CAPM and Risk Premium results, but LEI ultimately determines that sole reliance on the CAPM is appropriate.

Concentric disagrees with the following aspects of LEI's analysis to set the base ROE: 1) primary reliance on a single model to estimate the authorized ROE rather than multiple methodologies; 2) certain inputs to the CAPM analysis, including LEI's use of raw betas rather than Blume adjusted betas and the level of the market risk premium; 3) LEI's concerns with the DCF model to estimate the cost of equity for regulated utilities; and 4) the exclusion of an adjustment for flotation costs and financing flexibility, which is a departure from the OEB's past practice of allowing an adjustment of 50 basis points

With regard to LEI's reliance on the CAPM analysis to re-set the base ROE in the formula, Concentric's view is that the use of multiple methodologies to estimate the cost of equity is the preferred approach, both from the standpoint of financial principles and regulatory precedent in other jurisdictions. We elaborate on the financial principles previously in this report, and Figure 45 of LEI's report demonstrates that most North American jurisdictions rely on multiple models to establish the authorized ROE. Although LEI shows in Figure 45 that the AUC relies on an Equity Risk Premium approach, the base ROE in the new Alberta formula was based on the average results of the CAPM and DCF models. If LEI had based its ROE recommendation on Alternative #6, which uses multiple methodologies, the authorized ROE for Ontario's utilities would be 9.46 percent, as shown in Figure 46 of LEI's report.

In response to the specific inputs LEI has employed in its CAPM analysis, the risk-free rate in Concentric's analysis is based on the forecast 10-year government bond yields for Canada and the U.S. from Consensus Economics for the period from 2025-2027 plus the average spread between 10 and 30 year government bonds. LEI, on the other hand, has used an average forecast of the 30 year Government of Canada bond yield from six major Canadian banks for the four quarters of 2025. Although Concentric has used a different method and source for the risk-free rate in our CAPM analysis, we do not specifically object to LEI's use of a 30-year government bond forecast in the CAPM and we have adopted that approach for the Long Canada Bond Forecast as discussed in the next section of our Report.

With regard to beta, Concentric believes it is appropriate and consistent with empirical financial research to use Blume adjusted betas rather than raw betas for the reasons discussed earlier in our Report. In addition, Concentric's CAPM analysis uses weekly betas from Value Line and Bloomberg, which are based on five years of market return data, while LEI has calculated daily betas for the companies in its three proxy groups. LEI then adjusts these raw betas for differences in financial leverage between the proxy group companies and Ontario's electric and gas utilities. Concentric has performed a similar calculation using the Hamada equation, although we have not relied on that version of our CAPM analysis in our ROE recommendation. If LEI had used Blume adjusted betas calculated weekly over five years in Figure 39 of its report, the weighted average beta for the companies in LEI's three proxy groups (as shown in Figure 40 of LEI's report) would be 0.827, and the average CAPM result (as shown in Figure 41 of LEI's report) would be 10.07 percent, not including an adjustment for flotation costs and financial flexibility.

LEI uses a market risk premium ranging from 7.28 percent to 10.16 percent based on U.S. historical return data for the most recent 10-, 20- and 30-year periods. Concentric's CAPM analysis relies on an average Canadian and U.S. historical market risk premiums of 6.39 percent, based on Kroll data going back to 1926 in the U.S. and 1919 in Canada. The differences are that LEI has only relied on U.S. return data while Concentric has averaged Canadian and U.S. return data, and LEI has used shorter time periods to compute the MRP while Concentric has conservatively relied on the entire historical dataset.

LEI states on page 51 of its report that, "Discounted Cash Flow (DCF) valuation is the most fundamental approach to valuing a firm," yet LEI does not utilize the DCF model when establishing its base ROE recommendation in Ontario. LEI expresses concerns with the DCF model for purposes of estimating the authorized ROE for Ontario's utilities. In particular, LEI comments that the projected earnings growth rates from equity analysts tend to be overly optimistic, causing the results of the DCF model to be overstated. As discussed previously in our Report, Concentric does not share this concern with analyst growth rates being too optimistic for the companies in our proxy groups, as shown in Figure 10 of our Report. Nevertheless, Concentric has conservatively relied on the Multi-Stage DCF model rather than the Constant Growth DCF model, thereby moderating the effect of near-term EPS growth rate projections in years 1-5 with long-term projected GDP growth for Canada and the U.S. in years 11-200. We believe this adequately addresses any concerns the Board may have with optimism bias in short-term EPS growth rates.

Lastly, Concentric has included an adjustment of 50 basis points to the results of our DCF and CAPM results for flotation costs and financial flexibility, consistent with prior precedent in Ontario as well as most other Canadian jurisdictions. LEI has not included an adjustment for flotation costs and financial flexibility, however, arguing that such costs should be recovered as operating expenses if they are incurred during a rate year. LEI's recommendation is inconsistent with Canadian regulatory precedent on this issue and fails to recognize the need for regulated utilities to have sufficient financial flexibility to raise capital under a variety of capital market conditions. This is particularly important given the significant capital investments that will be required in response to the Energy Transition. Further, as discussed previously, LEI's approach puts Ontario utilities at risk of not recovering these costs simply because they were not incurred in the test year or are expected to be incurred over the rate plan. LEI's approach, therefore, would appear to go against LEI's principles of "transitioning away from the status quo only if the associated benefits are material," and "fairness in approach to consumers and utilities."

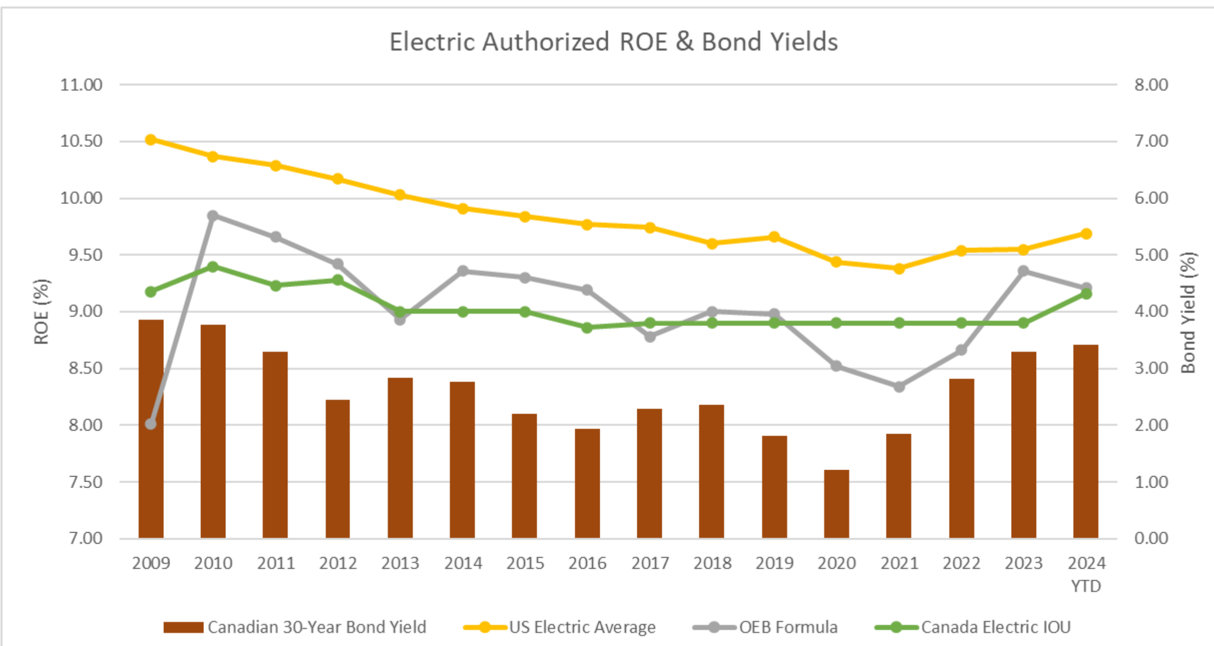
If the OEB were to continue to include an adjustment for flotation costs and financing flexibility, LEI's CAPM results would increase to 9.45 percent and the results of Alternative #6 (the average of the CAPM, DCF, and ERP models) would increase to 9.79 percent,[1] which is within 21 basis points of our ROE recommendation of 10.0 percent. (*LEI Report, p. 126)*

VI. THE ONTARIO ROE FORMULA

A. Introduction and Summary

Based on our analysis, we conclude that the existing methodology (i.e., the current OEB formula) has generally produced a return on equity that is consistent with returns for electric and gas utilities elsewhere in Canada. The ROE produced by the formula, however, is substantially lower than authorized returns for comparable risk electric and gas utilities in the U.S. and lower than the results of traditional models used to estimate ROE such as the DCF and CAPM. Figure 28 and Figure 29 below compare the returns produced by the Ontario formula to returns for other Canadian and U.S. electric and gas utilities from 2009-2024 YTD.

Figure 28: Ontario Formula vs Canadian and U.S. Electric Authorized ROEs



II. Fair Return Standard

A. General Principles

We are instructed by counsel that the FRS frames the discretion of the Board by setting out three requirements that must be satisfied in any cost of capital determination. These are mandatory legal requirements described by the Supreme Court of Canada as an "absolute" obligation.[8]

All of our analyses have been conducted with a view to the FRS and ensuring that the methodology we propose is compliant with it.

A fair return on capital must allow "as large a return on the capital invested in its enterprise, which will be net to the company, as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability, and certainty equal to that of the company's enterprise."[9] More recently, the Supreme Court of Canada has commented:

> *"[T]he utility must, over the long run, be given the opportunity to recover, through the rates it is permitted to charge, its operating and capital costs ("capital costs" in this sense refers to all costs associated with the utility's invested capital).* ***The required return is one that is equivalent to what they could earn from an investment of comparable risk****. Over the long run, unless a regulated utility is allowed to earn its cost of capital, further investment will be discouraged and it will be unable to expand its operations or even maintain existing ones. This will harm not only its shareholders, but also its customers."* [emphasis added][10]

A fair return must:

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[8] 2009 Board Report, p. 18, citing *British Columbia Electric Railway Co. Ltd. v. Public Utilities Commission of British Columbia et al,* [1960] S.C.R. 837, at p. 848.

[9] *Northwestern Utilities Limited v. City of Edmonton*, [1929] S.C.R. 186. Other seminal statements of the FRS come from *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia et al*., [1923] U.S.S.C. 160;, and *Federal Power Commission v. Hope Natural Gas Company*, 320 US 591 (1944)

[10] *Ontario (Energy Board) v. Ontario Power Generation Inc.*, 2015 SCC 44, para. 16

- Be comparable to the return available from the application of invested capital to other enterprises of like risk (the comparable investment standard);
- Enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and
- Permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).[11]

All three standards or requirements must be met, and none ranks in priority to the others.[12] In 2009, the Board specifically commented that "that focusing on meeting the financial integrity and capital attraction tests without giving adequate consideration to comparability test is not sufficient to meet the FRS."[13]

B. Application of Fair Return Principles

We note several characteristics of a fair return that are relevant to our proposed methodology and our critiques of the LEI report:

- The FRS expressly refers to an opportunity cost of capital concept, meaning it is prospective rather than retrospective;[14]
- A fair return is determined by applying the principles described in this section, not "conducting a simple mathematical calculation using a single formula-based model."[15] In 2009, the Board agreed that no single test is, by itself, sufficient to ensure that all three requirements of the fair return standard are met.[16] The British Columbia Utilities Commission has acknowledged the same principle in its recent rate-setting proceeding;[17]

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[11] 2009 Board Report, p. 18, citing National Energy Board. RH-2-2004, Phase II Reasons for Decision, TransCanada PipeLines Limited Cost of Capital. April 2005. p. 17.

[12] 2009 Board Report, p. 19.

[13] 2009 Board Report, p. 19.

[14] 2009 Board Report, p. 19.

[15] *Liberty Utilities (Gas New Brunswick) LP, as represented by its general partner, Liberty Utilities (Gas New Brunswick) Corp. v. New Brunswick Energy and Utilities Board*, 2022 NBCA 29, para. 26, citing *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia et al*., [1923] U.S.S.C. 160; *TransCanada Pipelines Ltd. v. National Energy Board*, 2004 FCA 149; and the 2009 Board Report.

[16] 2009 Report, p. 26.

[17] British Columbia Utilities Commission Generic Cost of Capital Proceeding (Stage 1) Decision and Order G-236-23 dated September 5, 2023, p. 64.

- While a fair return should not see consumers "paying more than is required to maintain safe, reliable and economic service"18, the effect of rate changes on consumers is not itself a determining factor in assessing whether a proposed return meets the FRS. The Federal Court of Appeal has been clear that the rate of return on equity must be determined solely on the basis of a company's cost of equity capital and that "the impact of any resulting toll increase is an irrelevant consideration in that determination;"[19]
- The capital attraction standard, indeed the FRS in totality, will only be met if the cost of capital determined by the Board is sufficient to attract capital on a long-term sustainable basis given the opportunity costs of capital. It is not satisfied merely by being "non-confiscatory" or allowing the utility to avoid bankruptcy;[20] and
- When identifying comparator jurisdictions and entities for the purpose of assessing whether the return is comparable to the return available from invested capital in other enterprises of "like risk" (i.e., the comparable investment standard), comparators are not required to be identical. They must merely share similarities and empirical analysis must be performed to determine if they are "like".[21]

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18 Alberta Utilities Commission Report dated October 9, 2023, "Determination of the Cost-of-Capital Parameters in 2024 and Beyond", Decision 27084-D02-2023, para. 24, citing Decision 22570-D01-2018.

19 *TransCanada PipeLines Ltd. v. National Energy Board*, 2004 FCA 149, paras. 35-43. The Court caveats this comment that the reviewing body can have regard to rate shock and preferring to incorporate changes over time, as long as the utility is ultimately compensated in time and the delay can be implemented without economic loss.

20 2009 Board Report, p. 20.

21 2009 Board Report, p. 21.

III. Benchmarking of ROEs to Comparable Jurisdictions

A. Overview

The FRS' comparable investment standard discussed in the previous Chapter states that the utility must have the opportunity to earn a return that is comparable to investments of similar risk. One indicator of whether a regulator is meeting this standard is comparing the authorized returns with jurisdictions that operate under similar circumstances. In this Chapter, Nexus Economics provides an analysis of the authorized return that the local regulator has authorized for distributors in the following jurisdictions:

- Alberta;
- British Columbia;
- California;
- New York; and
- Massachusetts.

We conclude that the current authorized ROE in Ontario, and ROE proposed by LEI, are far below the ROE in what we consider to be appropriate peer jurisdictions. Figure 5 below demonstrates this failure.

B. Nexus Economics' Analysis of Jurisdictions

In this section, we discuss our reasons for selecting the above jurisdictions as reasonably comparable to Ontario, as well as the results of our review.

The above jurisdictions were chosen based on several criteria.

1. Jurisdictions Operating in the Canadian / U.S. Financial Market

Only peers operating in the Canadian / U.S. financial markets should be included in the Board's comparable analysis. Firms operating in other financial markets, including the UK and Australia, operate under different legal, institutional, and macroeconomic circumstances which could influence utility ROEs.

Nexus Economics rejects LEI's proposed inclusion of the United Kingdom and Australia because they operate outside of the Canadian / U.S. Financial Market. Further, we added Massachusetts to the peers as an instructive peer jurisdiction.

2. Limited or No Generation Services

Ontario is a retail open-access jurisdiction. All comparable jurisdictions listed above, except for California and British Columbia, are also retail open access jurisdictions. California can best be characterized as a hybrid-jurisdiction because it allows community aggregation that an outside firm of agency provide generation services to retail customers. Further, certain California customers are grandfathered as retail open access customers. Fortis BC has been included because it has limited electric generation capacity.

3. Jurisdictions Adopting Strong Electrification Policies

As discussed further in Chapter IV (Risk Factors), Ontario is embarking on an electrification policy as a vehicle to reduce greenhouse gas emissions. Embracing electrification policies triggers several outcomes including:

- Significant increases in load;
- Increased capital spending to serve the increases in load; and
- Planning for new or increasing consumptions for electric end-uses**,** including space heating and electric vehicles

The IESO projects peak demand load growth to average 3.3 percent per year in the next 25 years. Jurisdictions that are not proposing electrification are not expected to achieve that level of load growth and are thus not appropriate comparators for assessing a fair return.

Nexus Economics has identified electrification policies in all the peers it proposes.

4. Adoption of Advanced Regulatory Mechanisms

Since the 1990s, Ontario has embraced advanced regulatory mechanisms. The peer jurisdictions have adopted multi-year rate plans and, in some cases, i-X mechanism PBR mechanisms, which adjust prices based on inflation and productivity.

All the peers Nexus Economics proposes operate under some form of IRM or multi-year rate plan. Further, each jurisdiction offers mechanisms for recovery of targeted costs.

C. Jurisdictional Overview

Electric utilities in Ontario operate under a regulatory and policy environment similar to other North American jurisdictions where allowed ROEs are typically higher than in Ontario. The defining features of these regulatory environments include:

- A commitment to decarbonization and the adoption of enhanced, clean electrification and similar net zero policies to Ontario;
- The use of innovative regulatory and ratemaking mechanisms that strengthen utilities' performance incentives and reduce the costs of regulation. These mechanisms include "performance-based" and other types of multi-year rate plans;
- Regulatory provisions that enable companies to undertake necessary capital expenditures that cannot funded by other sources of utility revenues; and
- Provisions for the recovery of unpredictable costs through other regulatory mechanisms (e.g., Z-factor, storm recovery).

Important elements of the five comparable/peer regulatory environments are briefly described below.

1. Alberta

Since implementing its first province-wide incentive regulation plan for energy utilities in 2012, the Alberta Utilities Commission (AUC) has developed an innovative regulatory framework that puts particular emphasis on flexible but efficient capital investment. The second PBR plan included a "k-bar" formula[22], tied to each utility's historical capex, that allowed for automatic revenue adjustments to meet capital spending needs. The second plan also includes a capital recovery mechanism that companies can use to request cost recovery for less predictable capital costs. In the third approved PBR plan, the AUC noted that K-bar revenues do not have to be restricted to capital spending. There has been considerable interest in AUC's capital cost mechanisms in other jurisdictions. Alberta has

[22] A K-Bar mechanism provides recovery certain capital expenditures. For a detailed discussion of K-Bar mechanisms in Alberta see "2024-2028 Performance-Based Regulation Plan for Alberta Electric and Gas Utilities at https://efiling-webapi.auc.ab.ca/Document/Get/794425.

not emphasized energy transition policies as much as some other similar utilities, but the third PBR plan did expand its capital cost recovery mechanisms to include energy transition expenditures.

2. British Columbia

British Columbia has been using incentive-based and multi-year formula rate plans since the 1990s. Its most recent regulatory proceedings for FortisBC allow for separate cost recovery of most projected capital expenditures for both gas distribution and vertically integrated electric power operations. Energy transition issues are also important in Fortis BC's most recently proposed incentive ratemaking plan.

3. Massachusetts

Massachusetts has been the most active U.S. jurisdiction for performance-based regulation since its first approved PBR plan in 1997. About a decade later, the Commonwealth implemented statewide revenue decoupling, and recent legislation has accelerated Energy Transition policies. In 2003, National Grid proposed an incentive-based regulatory mechanism explicitly designed to achieve the Commonwealth's energy transition objectives.

4. New York

In 2015, New York launched a Reforming the Energy Vision (REV) initiative that focused on establishing a "clean, resilient and affordable" energy system for New Yorkers. The REV had separate tracks for encouraging distributed energy resources and implementing innovative ratemaking approaches. The latter emphasized the importance of creating value for customers and achieving policy objectives, which highlighted the energy transition.

5. California

California has adopted various forms of incentive regulation for several decades. The current approach is a multi-year rate plan. Similar to Ontario, the multi-year rate plan is a separate proceeding from the cost-of-capital proceeding.

D. Comparison of Authorized ROEs in the Comparable Jurisdictions

Nexus Economics compared authorized ROEs for Ontario versus its peers. In order to ensure that the results were truly comparable, the ROEs were adjusted for the equity thickness of the firms in each jurisdiction because the equity thickness in the deemed capital structure in Ontario is different from that of the peer jurisdiction.[23] In other words, we made mathematical adjustments in order to facilitate an apples-to-apples comparison.

Figure 5 – Authorized ROEs for Ontario and Peer Jurisdictions (Re-levered to 60:40)[24]

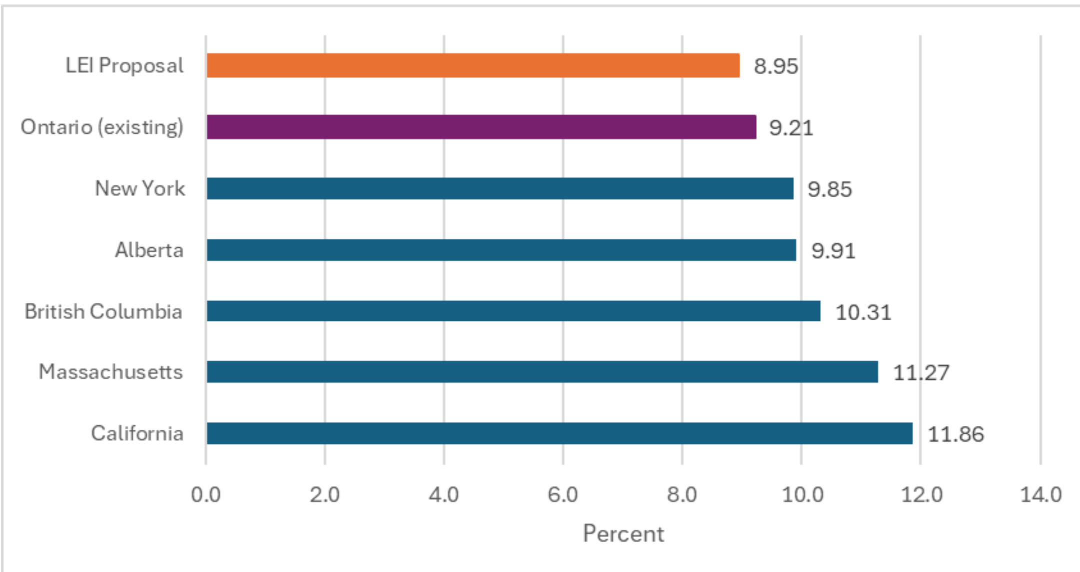

Figure 5 demonstrates that the authorized ROE proposed by LEI of 8.95 percent is significantly below those of Ontario's peers. The next lowest authorized ROE is New York in 2023, 90 basis points above LEI's proposed rate for Ontario and 60 basis points above the current Ontario ROE. The simple average of the peers is 10.64 percent, which is 1.69 percentage points higher than LEI's recommended 8.95 percent ROE. The comparison suggests that the LEI proposal does not meet the FRS in that it is substantially below the

[23] Deemed Debt-to-Capital Ratio in Ontario is 60.0 percent. The average Authorized Debt-to-Capital Ratio for all of the comparables is lower. California is 48.8 percent; New York is 52.0 percent; Massachusetts is 49.7 percent; British Columbia is 55 percent; and Alberta is 55 percent. (Sources are S&P SNL data for US comparables and various Decisions for British Columbia and Alberta.)

[24] US data are from S&P's SNL; Canadian firms are from Orders. All are re-levered from their own authorized debt ratios to the Deemed Debt Ratio of 60 percent debt.

ROEs earned by utilities operating in the peer jurisdictions and would not offer a competitively priced investment.

limitations of a single approach. Instead, it uses basic economic cost-of-equity models that are common in regulation, investments, and valuations; it is prospective where possible rather than based on historical data; and it does not incorrectly attribute a country risk premium to the US versus Canada.

We turn first to the issue of the relevant market for capital for Ontario service providers, insofar as this informs the entirety of our analysis as well as our criticism of LEI's CAPM analysis.

B. The Canadian and US Capital Markets are Integrated into a Single North American Capital Market

1. Explanation of the Issue and Why it is Important to this Proceeding

We conclude that capital relevant to the Ontario electric service providers ultimately comes from a single, integrated North American capital market. This conclusion is important for two reasons. First, the conclusion that the markets are integrated provides the basis for our selection of risk-comparable firms from the pool of North American electric utilities. Second, the conclusion is the basis for determining that LEI errs in its application of the CAPM to its base cost of equity result and to the annual adjustment mechanism.

Our conclusions regarding capital market integration are consistent with the 2009 Board Report, which concluded that Canada and the US capital markets were one-and-the-same, and accepted the use of selected US electric utilities as firms of comparable risk ("comparables") to the target firms.[38]

Ontario electricity distributors must raise capital funds from somewhere and it is important to understand how scarce funds are allocated in the market.

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[38] 2009 Report, p. 22 accepting the Concentric Economics approach to winnowing the field of US-based electric service providers.

As we have discussed, the FRS is important here because the FRS correctly recognizes the economic principle of opportunity cost. In this context, the notion of opportunity cost is that a firm's cost of equity will equal the cost of equity of its risk-comparable firms in an integrated market. Accordingly, the analysis must determine what the costs are for these firms and then apply that result to the target firm. Any proposed adjustment that is due to crossing a border must be evaluated in terms of market (dis)integration and undiversifiable differences in country risk. Absent these two conditions, the result for the comparable firms must be applied to the target firm under the opportunity cost concept, which is fundamental to the FRS.

2. Analysis of the North American Capital Market

Defining the relevant market is an important issue in regulation. Markets generally are defined in two dimensions: product and geography.[39] The relevant product here is capital, and the relative fungibility of money[40] means that from the user's point of view capital is capital. In a simple example involving gasoline, the relevant market definition question is whether a significant, non-transitory price increase at the pump would result in sufficient number of drivers moving to another gas station so as to make the initial price increase unprofitable.[41] The analogy applied here is whether a Canadian firm facing overpriced capital in Canada reasonably would raise capital in the US instead.[42] The answer is unambiguously yes. The product is similar enough that capital from US exchanges is equivalent to capital from Canadian exchanges.

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39 See, e.g., Federal Trade Commission. Market Power Handbook, p. 61.

40 We say "relative fungibility" because Canada and the US use different currencies and there is always exchange rate risk that must be either borne or hedged against.

41 The US antitrust analysts also apply the so-called S-SNIP test to determine if a small but significant non-transitory increase in the price would result be unprofitable due to customer movement to another alternative in the market. See, e.g., HORIZONTAL MERGER GUIDELINES. (2010). US Federal Trade Commission, §4.1.1.

42 MARKET POWER HANDBOOK, COMPETITION LAW AND ECONOMIC FOUNDATIONS. (2nd ed.) 2012. American Bar Association. Available at Market Power Handbook. Competition Law and Economic Foundations. Second Edition - ABA Antitrust Library - Books and Journals (vlex.com). Hereafter Market Power Handbook.

Fortis (for example) trades on the NYSE, as do over 100 other Canadian firms.[43] BCE, the Canadian telephone company, raised $1.45 billion in debt in the US, with about half of that long-term (30-year) debt at about 1.2 percentage points over US Treasuries,[44] despite the fact that US 30-year Treasury bonds were over a percentage point higher than Canadian 30-year Treasury bonds at that time.[45]

As for the geographic dimension of markets, geographic distances do not exist in any practical way for capital moving between Canada and the US.

The relative scale of the US and Canadian capital markets illustrates why the capital markets are homogenized. The NYSE and NASDAQ are about 14 times the size of the Toronto exchange. Indeed, Nvidia alone (NASDAQ) has a greater market capitalization than the entire Toronto exchange.[46] As noted, many larger Canadian companies are listed on US exchanges.

There is also a high degree of economic integration between Canada and the US, which would be related to capital market integration so that these transactions can be financed. 75.36 percent of Canada's exports are to the US[47] and about half of Canada's imports are from the US.[48]

LEI appears to agree that the Canadian and US capital markets are integrated into a single North American capital market. LEI provides evidence that the North American capital markets are integrated in explaining why it would not use Canadian data alone to

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43 See, e.g., Yahoo Finance regarding Fortis. Over 100 Canadian firms trade on the NYSe and another 100+ on the US NASDAQ. See, "The Complete List of Canada Stocks Trading on US Markets." TopForeignStocks (at The Complete List of Canada Stocks Trading on the US MarketsTopForeignStocks.com).

44 Chunzi Xu and Esteban Duarte. "BCE borrows $1.45 billion from U.S. debt market." February 2, 2024. Financial Post. Available at, https://financialpost.com/telecom/bce-borrows-1-45-billion-us-debt-market.

45 Canadian Treasury Bonds from Marketwatch (TMBMKCA-30Y). US Treasury bonds from St. Louis Federal Reserve (FRED). Both evaluated February 16, 2024.

46 Nvida market cap was $3.22 (2024-06-17) versus Toronto Exchange $2.55 USD.

47 Canada Exports by country US$000 2017 - 2021 | WITS Data (worldbank.org) and (WITS-Partner-Timeseries.xlsx).

48 Canada Imports By Country. At Trading Economics. https://tradingeconomics.com/canada/imports-by-country.

estimate a Market Risk Premium. This implies that Ontario service providers compete with the US counterparts for the same capital. As LEI notes:

> *[The Maple 8 pension funds] put 25% of their portfolio to domestic Canadian investments, which indicates that investors are more likely to consider their MRP opportunity costs based on US MRP.*[49]

We concur with LEI that the US-based Market Risk Premium is relevant to Canadian investors, indicating that the Canadian and US capital markets essentially are one. We also examined the 2024 version of Aswath Damodaran's "Country Default Spreads and Risk Premiums" and observed that both US and Canadian country risk is 0.00 percent.[50] What this means is that there is no call for a country adder (or "subtractor") when evaluating capital costs. In an opportunity cost context, this means that the cost of equity incurred by US firms of comparable risk is the same as the cost of equity incurred by Canadian firms, which is the law of one price—all buyers pay the same price for the same product within the market. Within an integrated market, the law of one price prevails: Whatever the other buyer pays for a good or service is what you have to pay. There is no adjustment for differences in interest rates because capital is coming from the same market and has one price (at a given level of risk).

3. Implications of Capital Market Integration

The above analysis of the Canadian and US economies is indicative of a single capital market.

An important implication of the single capital market conclusion is that there should be no adder or subtractor to the cost of capital based on where the firms are located since these firms seek capital from the same source. There will be a single price for risk-free assets, and a single price for risky assets of the same or comparable riskiness. Firms that

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[49] LEI Report p. 120 (footnotes omitted).

[50] Aswath Damodaran, "Country Default Spreads and Risk Premiums," Last Updated January 5, 2024. Available at Dr. Damodaran's website. At the time of the update, both the US and Canada were rated as AAA by Moody's Investor Services. Other agencies have downgraded US Treasury bonds. See, e.g., See, e.g., World Credit Ratings (worldgovernmentbonds.com).

are identified as risk-comparable to the Ontario electric service providers should not be adjusted based on whether the firms are located in a US state or in Canada.

Our conclusion with regard to a single North American capital market supports the use of US (and Canadian) firms in the development of risk-comparables, as was concluded by the Board in 2009.[51] It also supports our assertion that LEI errs in substituting the forecasted 30-year Canadian Treasury rate for a US rate in its specification of the CAPM.

C. Shortcomings of the LEI Approach

In this Section, we discuss shortcomings to LEI's recommendation that the Board look only at the results of the CAPM in determining a rate of return on equity under the Fair Return Standard. In this Section, we discuss the following:

- How we arrived at the numbers that we attribute to LEI's analysis in our Table 4.
- Shortcomings of using only one method to compute a rate of return on equity that is compatible with the Fair Return Standard.
- LEI's application of the CAPM and the error in application;
- LEI's DCF and why LEI's reasons for rejecting the DCF for consideration by the Board are inadequate; and
- LEI's use of its risk-premium analysis to inform the annual adjustment mechanism without considering the implications of that analysis for the base return on equity.

1. How the LEI Results are Adjusted in Table 4

Our Table 4 shows that when all of LEI's methods are included, and when they are adjusted for leverage and taxes, the resulting simple average is close to our own ROE results. For clarity, we describe those adjustments here.

First, with regard to the CAPM we made a single adjustment: swapping out the Canadian forecasted long-term bond rate with a forecasted US 30-year bond rate. Guided by the

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[51] See, e.g., 2009 Board Report, p. 23. "The Board is of the view that the U.S. is a relevant source for [risk] comparable data." The Board rejected arguments to limit comparables to Canadian firms (2009 Report, pp. 21-22.)

M3-2-OEB Staff-32

Note this interrogatory has been asked by LEI

Ref: Nexus Report, p. 25

Nexus stated the following:

LEI has identified business and financial risks in its report. However, given the changes in industry structure occurring due to decarbonization and electrification efforts, Nexus Economics has also identified a category of risk that LEI ignores: strategic risk.

a) What specific business decisions face “strategic risk”?

Response

Some non-exhaustive examples of strategic risk include:

- Distributors are required to move into business lines and operations that they traditionally have not operated in, such as non-wires alternatives.
- Uncertainties regarding load growth can trigger mismatches with infrastructure investment.
- Regulatory lag associated with the IRM. The existing IRM mechanism was developed for an environment of relatively flat load per customer. In contrast, the energy transition would expect to trigger increasing load per customer.

b) Please explain how ‘strategic risk’ is not evaluated as part of ‘business risks’ and ‘financial risks’ as assessed by OEB as well as major rating agencies (such as S&P Global, DBRS Morningstar, and/or Moody’s).

Response:

Strategic risk is associated with changes in the industry structure whereas business risk is associated with risk associated with the ongoing operations of a business in a static environment.

M3-10-CME-12

Ref: Exhibit M3, p. 18

At page 18, Nexus states that its opinion is that peers operating in Canada and the United States are entities of like risk, while entities operating in the UK and Australia are not. Nexus states "Firms operating in other financial markets, including the UK and Australia, operate under different legal, institutional, and macroeconomic circumstances which could influence utility ROEs".

(a) Please confirm that entities operating in Canada operate under different legal circumstances than firms operating in the United States. If this is not confirmed, explain why fully.

Response:

Nexus Economics is not a law firm, and the members of the project team are not attorneys and cannot render a legal opinion. It is our experience working in Canada, the United States, and certain Commonwealth Countries that many of the policy and regulations that exist in Canada regarding the public utilities are similar.

(b) Please confirm that entities operating in Canada operate under different institutional circumstances than firms operating in the United States. If this is not confirmed, explain why fully.

Response:

All regulatory jurisdictions in Canada and the U.S. "..operate under different institutional circumstances…" in some form. However, parallels and lessons can be drawn from peer regulatory entities.

(c) With respect to "macroeconomic circumstances", is Nexus referring to its opinion that Canada operate in an integrated capital market?

Response:

Broadly, yes. Please see pp. 43-45 of the Nexus Report.

(d) Please provide any other macroeconomic circumstances that Nexus believes are the same or comparable as between Canada and the US but differ in relation to Canada / the UK or Australia.

Response:

We concluded (at pp. 42-46 of our Report) that Canada is part of the North American capital market. Canada and the US nevertheless can have different macroeconomic circumstances (e.g., unemployment rates, inflation), just as different Canadian provinces (and different US states) can have varying macroeconomic circumstances.

(e) On Page 17, Nexus states that enterprises of like risk do not need to be identical, but must merely share similarities and empirical analysis must be performed to determine if they are like. Is it Nexus' view that enterprises in the UK and Australia do not share any similarities whatsoever?

Response:

No, but it is our opinion that any similarities are not sufficient to include them in the list of comparables, particularly above other comparable jurisdictions in the US and Canada. Please see our Report at pp. 43-45 regarding circumstances (trade and financing) that indicate the US capital markets are integrated and that Ontario electric utilities compete for capital in the same market as US electric utilities. It is Nexus' view that enterprises in the UK and Australia do not share those similarities with Canada.

(f) If the answer to (e) is that they do not share any similarities, please explain why.

Response:

No, that is not our opinion. Our opinion is that the similarities are not sufficient to include them in the list of comparables. We did not conclude that they do not share *any* similarities.

(g) If the answer to (e) is that they do share some similarities. Please provide all empirical analysis performed by Nexus to demonstrate whether these entities are "like" or not.

Response:

We did not perform an empirical analysis of these entities. We evaluated for risk comparability only those that were traded on the US or Canadian stock exchanges.

United States

A soft landing in 2024

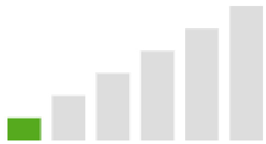
Last update – January 2024

Country rating

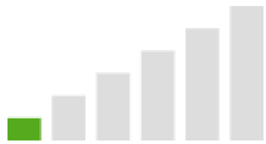
AA1

LOW RISK FOR ENTERPRISE

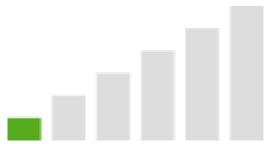
Economic risk



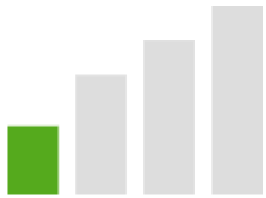
Business environment risk



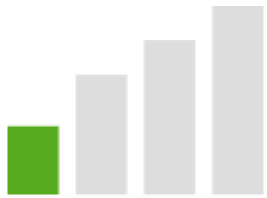
Political risk



Commercial risk



Financing risk



The country risk assessments are your North Star metrics to make the right decision for your business and understand the risks in international trade

Canada

High interest rates to weigh on the economy in 2024

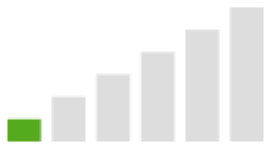
Last update – January 2024

Country rating

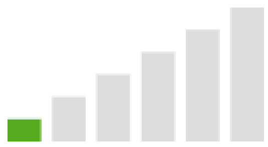
AA1

LOW RISK FOR ENTERPRISE

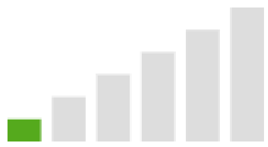
Economic risk



Business environment risk

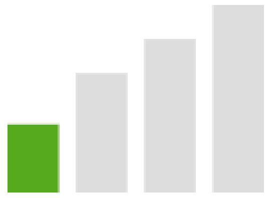


Political risk



Commercial risk

Financing risk



United Kingdom

Britain great again?

Last update – July 2024

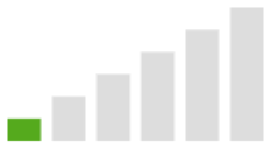
United Kingdom
Country rating | Strengths & weaknesses | Economic overview | Trade structure

Country rating

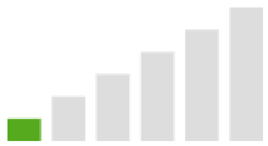
AA1

LOW RISK FOR ENTERPRISE

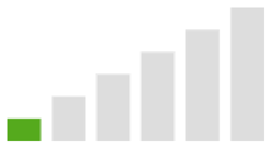
Economic risk



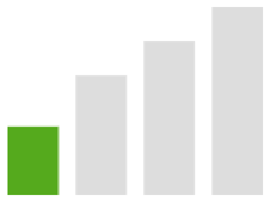
Business environ-ment risk



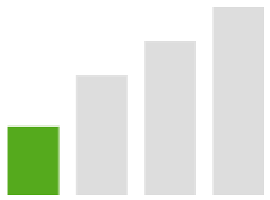
Political risk



Commercial risk



Financing risk



Australia

Troubled waters

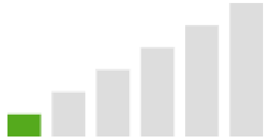
Last update – July 2024

Country rating

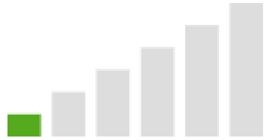
AA1

LOW RISK FOR ENTERPRISE

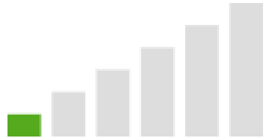
Economic risk



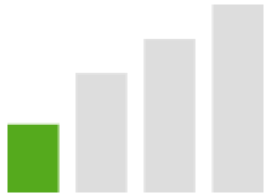
Business environ-ment risk



Political risk



Commercial risk



Financing risk