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November 28, 2024
Our File: EB20240063

Attn: Nancy Marconi, Registrar

Dear Ms. Marconi:

Re: EB-2024-0063 – Generic Proceeding on Cost of Capital – SEC Reply Argument

We are counsel to the School Energy Coalition ("SEC"). Attached, please find SEC's Reply Argument in the above-captioned matter.

Shepherd Rubenstein P.C.

Mark Rubenstein

cc: Brian McKay, SEC (by email)
Intervenors email)

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.

REPLYARGUMENT OF THE SCHOOL ENERGY COALITION

November 28, 2024

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1 OVERVIEW

1.1 ***Introduction***

1.1.1 The Ontario Energy Board ("OEB") initiated a generic hearing on its own motion to consider the methodology for determining the cost of capital, as well as other related matters, to be used in setting rates for electricity distributors, electricity transmitters, natural gas utilities, and Ontario Power Generation ("OPG").

1.1.2 After a full hearing, parties filed their final arguments on November 7, 2024, and were given the opportunity to a file reply. This is the Reply Argument of the School Energy Coalition ("SEC").

1.1.3 SEC does not intend to respond to each of the parties' initial submissions, but rather to highlight some of the major disagreements or address new arguments. Silence should not be construed as agreement. Furthermore, the two utility intervenors, the Ontario Energy Association ("OEA") and the Electricity Distributors Association ("EDA"), broadly adopt the positions and recommendations of their respective experts, Concentric and Nexus. SEC addressed the flaws of those expert reports in detail in its Final Argument.

1.1.4 The arguments and recommendations from several parties, including the OEA, EDA, Association of Power Producers of Ontario ("APPrO"), and OEB Staff, would result in a cost of capital that does not meet the Fair Return Standard ("FRS"). They rely on flawed expert evidence, unsound analysis, and recommended approaches to setting the most critical components of the cost of capital, the return on equity ("ROE") and equity ratio, that is too high, would unfairly burdens ratepayers and is neither just nor reasonable.

1.2 ***General Comments***

1.2.1 SEC continues to rely on the arguments, analysis, and recommendations made in its Final Argument.

1.2.2 The impact of an unreasonably high cost of capital is not only felt by ratepayers in the immediate term through higher rates, but also in the longer term, as it creates a greater incentive for utilities to undertake capital projects. SEC agrees with the Consumers Council of Canada ("CCC") and Pollution Probe, that higher-than-required ROEs only

exacerbate the existing utility bias toward capital expenditures, which creates barriers to a cost-effective energy transition.[1] The Energy Institute at Haas' (University of California, Berkeley) paper provides convincing research showing that in the U.S., not only are ROEs higher than several cost of capital benchmarks, but utilities also respond to higher ROEs by increasing capital spending, which generates additional returns at a considerable cost to customers.[2]

1.2.3 SEC cautions against accepting arguments made by the OEA and the CLD that rely entirely on comparisons between the capital structure and ROEs in other jurisdictions. AMPCO/IGUA summarized it best, noting that there is "circularity to such comparisons, in particular when experts led by utilities habitually argue for significant cost of capital parameter increases."[3] Utilities generally have an unfair informational advantage compared to ratepayer representatives and regulators. Sometimes, as was the case in a recent BCUC decision, there are no experts available to challenge the utilities' recommendations.[4]

1.2.4 The OEB should also reject the OEA's and EDA's arguments, that Dr. Cleary's recommendations are unreasonable because his approach differs from those of utility experts, or because other regulators have not yet adopted his recommendations.[5] Based on the available information it provided, no regulator has, by way of a litigated decision, accepted the cost of capital parameters recommended by any Concentric witnesses providing evidence in this proceeding.[6] The OEB has never agreed with the ROE or capital structure recommendations of Mr. Coyne or Concentric.[7] Moreover, the Nexus

[1] Consumers Council of Canada Submissions, p.10; Pollution Probe Submission, p.4

[2] Karl Dunkle Werner and Stephen Jarvis, Rate of Return Regulation Revisited, Energy Institute At Haas (Revised September 2024) (K5.5). See also the discussion beginning at Tr.5, p.167

[3] AMPCO/IGUA Submissions, para. 61

[4] Tr.3, p.165

[5] See OEA Submissions, para. 159-160; EDA, para. 119-121

[6] See M2-0-SEC-31, Attachment 1. Concentric has provided information on its previous recommended and the regulators approved cost of capital parameters (ROE and equity thickness) as a result of a decision since 2019.

[7] Most recently, the OEB did not accept the proposal from Enbridge (supported by the expert of Concentric) to increase Enbridge's equity ratio to 42% (*Decision and Order* (EB-2022-0200), December 21, 2023). It also did not accept Concentrics' cost of capital recommendations in, i) EB-2016-0152, the OEB rejected OPG's proposal (supported by the expert evidence) to increase its proposed equity thickness (*Decision and Order* (EB-2016-0152), December 28, 2017), ii) In EB-2011-0354, the OEB rejected Enbridge's proposal (supported by expert evidence of Concentric) to increase its equity ratio (*Decision on Equity Ratio and Order (*EB-2011-0354), February 7, 2013), iii) In EB-2009-0083, the OEB did not adopt the specific ROE recommendation proposed by Concentric (Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084), December 11, 2009, p.38).

experts have never filed cost of capital evidence in a proceeding like this for the OEB to assess how other regulators might react.[8]

1.2.5 The OEA and EDA also make unfounded allegations that Dr. Cleary is biased or partisan because he has only provided expert evidence for consumer interests.[9] This allegation is not only incorrect, but also deeply hypocritical, given that Mr. Coyne appears to provide expert evidence exclusively on behalf of utilities.[10]

1.3 ***Proxy Groups***

1.3.1 Both the EDA and OEA justify the companies in their respective proxy groups, even though the companies they include bear little resemblance, in various respects, to the utilities to which their proposed ROE recommendations are intended to apply.

1.3.2 The 2009 Report stated that "like" does not mean "same", but emphasized that "[t]he comparable investment standard requires empirical analysis to determine the similarities and differences between rate-regulated entities."[11] While no two utilities are the "same," not every utility is sufficiently "like" another. Despite this, the OEA, EDA, and their respective experts, Concentric and Nexus, do not propose to apply their recommended ROE to the sole Ontario utility with generation assets, OPG, yet their proxy groups are disproportionately composed of utilities with generation assets (i.e., vertically integrated utilities).[12]

1.3.3 Vertically integrated utilities carry higher risk than electricity distributors and transmitters. Moody's states, that "[g]eneration utilities and vertically integrated utilities generally have a higher level of business risk because they are engaged in power generation," which it considers "the highest risk component of the electric utility business."[13] Concentric agrees, noting that the "generation function is generally

[8] See M3-0-SEC-64

[9] OEA Submissions, para. 161; EDA Submissions, para. 120

[10] See M2, 182-188; M2-0-SEC-31, Attachment 1

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

[12] See Undertaking J.2.4. 15 of the 25 companies in Concentrics's North American Combined Proxy Group own generation assets (See Undertaking J2.4).

[13] Tr.2, p.148-149; Concentric Report Prepared for Ontario Power Generation (EB-2020-0290, C1-1-1, Attachment 1), p.63 (K2.6, p.25)

regarded by investors as being higher risk than electric transmission/distribution."[14] In the 2009 consultation process, Concentric attempted to address this issue by making a 40 basis points ("bps") downward adjustment to its then proposed electricity proxy group recommended ROE.[15] It made no such adjustment in its evidence in this proceeding.

1.3.4 Concentric's and Nexus's proxy groups also face significant issues that make them unsuitable for comparison to Ontario distributors. Concentric's proxy group includes utilities with material unregulated businesses[16] which are inherently riskier.[17] The Nexus proxy group includes many of the same companies, but also others even less comparable to Ontario utilities. For example, it includes companies where half their business is unrelated to energy (Alaska Power & Telephone Company[18] and Otter Tail Corporation[19]), utilities with credit ratings below investment grade (PG&E Corporation[20] and Hawaiian Electric Industries[21]), and companies whose distribution operations are primarily located in Central America (AES Corporation[22]).

1.3.5 The EDA claims that "[t]hese critiques are misplaced," "merely pick at marginal comparables," and "have no impact on the thrust of Nexus and Concentric analyses."[23] This is incorrect. The differences are significant. For instance, in response to Undertaking J4.2, Concentric provided a version of its financial models that excluded companies with generation assets or material unregulated operations (10% or greater). This adjustment reduced the ROE across proxy groups by 30 bps from its recommended amount of 40 bps from its analysis.[24] While Nexus may argue this reduction is immaterial, it is highly significant for ratepayers.

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[14] Tr.2, p.148; Concentric Report Prepared for Ontario Power Generation (EB-2020-0290, C1-1-1, Attachment 1), p.63 (K2.6, p.25)

[15] See Comments of Concentric Energy Advisors Inc., on behalf of Enbridge Gas Distribution, p.C-3, C-4 (EB-2009-0084, Enbridge Gas Distribution Inc., Written Comments, September 9, 2009, pdf pages 100-101).

[16] Each of NextEra, AltaGas, Enbridge Inc. and Spire Inc. all have unregulated operations above 10% (See J4.2, Attachment 1, 'CEA-2 Proxy Group' tab).

[17] Tr.2, p.54

[18] Tr.5, p.15-16; K5.1, p. 11-12

[19] Tr.5, p.16-17; K5.1, p.14-15

[20] Tr.5, p.20; K5.1, p.39

[21] Tr.5, p.21; K5.1, p.38

[22] Tr.5, p.23; K5.2, p.31

[23] EDA Submissions, para. 73

[24] Undertaking J4.2

1.3.6 The impact is even greater for Nexus, in that, if it had excluded comparators that are not similar to those proposed its recommended ROE would drop substantially. VECC calculated that if only utilities classified under the relevant NAICS code for electric power transmission, control, and distribution were included in Nexus's proxy group, the recommended ROE would fall to 9.43% from 10.92% (both excluding flotation costs).[25]

1.3.7 SEC acknowledges that using U.S. comparators is necessary due to the limited number of publicly traded Canadian utilities. The pool becomes even smaller when excluding those that are vertically integrated, or whose operating companies are primarily located in Canada. However, differences across borders must be carefully considered. U.S. utilities face different risks than Canadian utilities, particularly Ontario ones. This difference is evident in market data, where U.S. utility betas have historically been higher than Canadian utility betas.[26]

1.3.8 Credit agencies and sector analysts also recognize differences in regulation. This past summer, S&P acknowledged that lower ROEs and capital ratios for Canadian utilities, such as Alectra, compared to U.S. averages, are offset by the "regulatory support and lack of sectoral bankruptcies in Canada."[27] S&P emphasized that lower allowed equity ratios are "sufficiently offset by the OEB's track record of predictable regulatory support."[28]

1.3.9 The Canadian Gas Association (in conjunction with the American Gas Association), released a study on investor perspectives of natural gas utilities on the day initial arguments were filed, which found in comparing Canada and U.S. capital structures and ROE, that the "[t]he lower allowed ROEs found in Canada seem to associate with a slightly lower level of perceived risk, owing in part to a lower likelihood of underearning."[29] One analysist observed that "[t]his was attributed to the use of forward-looking test years, more frequent rate reviews, greater flexibility to adjust rates between major proceedings, and weather protection."[30] Furthermore, the report found that

[25] Undertaking J5.1

[26] M4, p.136; M4, Appendix C

[27] Fitch Affirms Alectra's IDR at 'A-'; Outlook Stable (Attachment to M3-10-SEC-72) (K5.1, p.41)

[28] Fitch Affirms Alectra's IDR at 'A-'; Outlook Stable (Attachment to M3-10-SEC-72) (K5.1, p.41)

[29] Canadian Gas Association and American Gas Association, Investor Perspectives on Natural Gas Utilities: A Canadian and United States Review (November 2024), p.19

[30] Canadian Gas Association and American Gas Association, Investor Perspectives on Natural Gas Utilities: A

"Canadian utility regulation tends to be more homogeneous and less politicized and tends to exhibit greater continuity than in the U.S."[31]

Canadian and United States Review (November 2024), p.19

[31] Canadian Gas Association and American Gas Association, Investor Perspectives on Natural Gas Utilities: A Canadian and United States Review (November 2024), p.19

1.3.10

2 RISK AND CAPITAL STRUCTURE

2.1 *Changes in Risk*

2.1.1 The OEA and EDA heavily rely on the evidence of their respective experts, Concentric and Nexus, to argue that business risk for utilities has increased due to the energy transition.

2.1.2 The OEB has recognized increased business and financial risk for natural gas utilities due to the energy transition, as reflected in its Phase 1 rebasing decision for Enbridge, which raised the company's equity ratio from 36% to 38%.[32] However, as discussed in SEC's Final Argument, the impact differs for electricity distributors and transmitters. Unlike natural gas distributors, which face concerns about declining or negative customer growth, electrification presents electricity distributors and transmitters with significant growth opportunities, reducing their business risk.

2.1.3 Increased capital spending from electrification only impacts financial risk if it materially affects cash flows, which has not yet occurred. LEI correctly observed this[33], and credit rating agency reports for Ontario utilities confirm it.[34] There have been no credit downgrades for Ontario electricity distributors and transmitters, let alone for increased capital spending. Hydro One exemplifies this, as its higher capital spending and larger rate base have enhanced its attractiveness as a low-risk investment offering reliable dividends.[35] Hydro One plans to maintain this trend, proceeding through its current rate term without requiring new equity investments[36], as it has done since at least 2019.[37]

2.1.4 OEB regulatory changes have also reduced risk for utilities by improving capital cost recovery mechanisms. Since 2009, the OEB has adopted significant changes, including the RRFE framework with multiple rate-setting mechanisms such as Custom IR[38], the

[32] Tr.2, p.54

[33] Tr.1, p.90-91

[34] See VECC Submissions, para. 119

[35] Hydro One Investor Overview (Post Second Quarter 2024), p.11,23 (K2.6, p.116, 128); Tr.2, p.141

[36] Hydro One Investor Overview (Post Second Quarter 2024), p.11 (K2.6, p.116); Tr.3, p.22

[37] M2-10-SEC-4(c) (K2.6, p.295)

[38] Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach (October 18, 2012)

introduction of the ACM[39], reduced ACM/ICM deadbands[40], expanded ICM eligibility during deferred rebasing[41], and the ability to recover costs for Non-Wires Alternatives during a rate term.[42] Recently, the OEB launched a consultation to advance performance-based regulation, with goals to "[e]nable utilities to cost-effectively meet the demands of the energy transition" and "[f]acilitate new investments."[43]

2.1.5 Additional changes have reduced volumetric risk with fixed distribution rates for most customers[44] and improved regulatory recovery through annual updates to LV rates through the IRM/rate adjustment process[45], and the inclusion of more up-to-date RTSR in rates.[46]

2.1.6 SEC agrees with OEB Staff that regulatory mechanisms impacting cost recovery "play an outsized role in increasing or decreasing utilities' business and financial risks."[47] Evidence from both LEI and Concentric agrees that the regulatory changes made by the OEB reduce utility risk.[48] LEI's conclusions, if anything, are understated, as they only reviewed a subset of regulatory developments since 2009.[49] S&P and Fitch Ratings also affirm the low-risk regulatory environment, describing Ontario as one of its "most credit-supportive regulatory jurisdictions"[50], and the OEB as being a "a highly constructive regulator"[51], with a "generally constructive regulatory framework."[52]

2.1.7 The OEA misinterprets the Enbridge Phase 1 decision's impact on the company's

[39] Report of the Board - New Policy Options for the Funding of Capital Investments: The Advanced Capital Module (September 18, 2014)

[40] Supplemental Report: New Policy Options for the Funding of Capital Investments (Jan 22, 2016)

[41] OEB Letter Re: Incremental Capital Modules During Extended Deferred Rebasing Periods (Feb 10, 2022)

[42] Advancing Performance-based Regulation (EB-2024-0129)

[43] EB-2024-0129, Advancing Performance-based Rate Regulation, OEB Stakeholder Consultation Presentation (November 19 2024), p.7

[44] M1, p.168; Board Policy: A New Distribution Rate Design for Residential Electricity Customer (April 2, 2015)

[45] See Updated Filing Requirements for Electricity Distribution Rate Applications, Chapter 3 (June 15, 2023)

[46] OEB Letter, 2024 Preliminary Uniform Transmission Rates and Hydro One Sub Transmission Rates (September 28, 2023)

[47] OEB Staff Submissions, p.5

[48] M1, p.74, 143; M2-3-SEC-34 (K6.2, p.92-94); Tr.2, p.125-126

[49] M1-3-SEC-11, p.2; Tr.2, p.61-65

[50] M2-10-SEC-41, Attachment 6, p.119

[51] Fitch Affirms Alectra's IDR at 'A-'; Outlook Stable (Attachment to M3-10-SEC-72, p.1) (K5.1, p.40)

[52] M2-10-SEC-41, Attachment 6, p.126,

current business risk.[53] S&P has reaffirmed Enbridge Gas's A- credit rating with a negative *outlook*, which was driven not by the Phase 1 Decision, but by a reassessment of Enbridge Inc.'s outlook following its acquisition of a number of U.S. gas utilities. In September 2023, S&P made the initial "revision on EGI to negative reflects the recent outlook revision on Enbridge to negative following its announced acquisitions of three of Dominion Energy Inc.'s U.S. regulated gas utilities (sic)."[54] While S&P noted potential for a gradual increase in Enbridge's business risk due to OEB views on the future of gas distribution, it still rates Enbridge's business risk as "excellent."[55] Subsequent actions by the Ontario Government, such as Bill 165[56] and the release of its vision document[57], demonstrate strong support for natural gas distribution, likely reducing Enbridge's business risk.

2.1.8 The OEA's reference to the recently introduced Bill 214 as a source of increased political uncertainty is unconvincing[58]. Bill 214, which allows the Minister of Energy to make regulations amending the DSC and TSC with respect to cost allocation and recovery, is intended to facilitate new customer connections and support housing and business growth.[59] This reduces distributor and transmitter risk by fostering growth opportunities. As the OEA's President and CEO, Mr. Brescia, noted in his enthusiastic press release supporting the announcement, "[t]he government's proposals will help make new housing more affordable and ensure businesses can get quick and affordable access to electricity."[60]

2.2 ***Capital Structure***

2.2.1 SEC disagrees with OEB Staff's position that the equity thickness for electricity distributors and transmitters should remain at 40%.[61] OEB Staff supports this position by citing LEI's view that no changes to capital structure are required, and suggesting the OEB retain its current approach, allowing utilities to apply for changes if they perceive

[53] OEA Submissions, para. 30

[54] M2-10-SEC-41, Attachment 1, p.116

[55] M2-11-CME-10, Attachment 1, p.2

[56] Bill 165, *Keeping Energy Costs Down Act, 2024*

[57] Ministry of Energy and Electrification, *Ontario's Affordable Energy Future: The Pressing Case for More Power*

[58] OEA Submissions, para 37.

[59] Ministry of Energy and Electrification, Ontario Reducing Costs for Future Homeowners (October 21, 2024)

[60] OEA Press Release: Ontario Energy Association (OEA) Supports Government of Ontario's Connecting Housing Plan (October 21, 2024)

[61] OEB Staff Submissions, p.35

an increase in business or financial risk.[62]

2.2.2 First, LEI did not conclude that no changes to capital structure are required. Its evidence indicates that risk has slightly decreased. However, LEI was not tasked with determining the appropriate equity thickness. LEI explicitly stated that assessing the suitability of the current equity thickness would require a "full assessment of business/financial risks (along with forward-looking cash flow modeling)," which was "outside the scope of [its] report."[63] To promote regulatory efficiency, LEI recommended maintaining the current capital structure, and allowing utilities to propose adjustments only if they experience increased risk.[64]

2.2.3 Second, OEB Staff's proposed approach, mirroring LEI's recommendation, that utilities may apply for changes to their capital structure if they perceive increased risk is fundamentally unfair to ratepayers because it is asymmetrical. There is no reason utilities should be able to request increases in their equity ratio based on perceived risk, without a corresponding mechanism to require reductions in their equity ratio when risk decreases. This lack of symmetry denies ratepayers the opportunity to benefit from reductions in utility risk.

2.2.4 OEB Staff's approach is also similar to the case-by-case method currently applied to OPG and Enbridge. Even if it were symmetrical and required utilities to justify changes in their equity ratio based on evidence of business and financial risks, it would be unworkable for most electricity distributors. With over 50 distributors in Ontario, the costs of preparing such evidence and litigating these matters would be cost prohibitive for many. Contrary to LEI's claim, deferring these matters to individual rate applications undermines regulatory efficiency.

2.2.5 For 15 years, customers have waited for the OEB to reassess the capital structure for electricity distributors and transmitters. Many of the regulatory mechanisms introduced to reduce utility risk have resulted in higher rates for customers. The language from credit rating reports describing Ontario as credit supportive simply means they find that OEB is "supportive of cost recovery, including the mechanism by which one-off costs or over-spends are recovered, if at all."[65] It is only fair that ratepayers now benefit from

[62] M1-2-VECC-17 (K2.3, p.90); M1, p.74, 143

[63] M1-2-VECC-17 (K2.3, p.90)

[64] Tr.2, p.70; M1, p.140

[65] M2-0-SEC-32, Attachment 4, p.10

reduced utility risk through a lower equity ratio.

2.2.6 Given that the OEB recently determined in a full hearing that the appropriate equity ratio for Enbridge Gas is 38%, it should acknowledge the relatively lower risk faced by electricity distributors and transmitters by reducing their equity ratio to 37%. This aligns with the equity ratio adopted and reaffirmed by the Alberta Utilities Commission ("AUC") for Alberta electric utilities, which Concentric has stated are comparable in risk to Ontario utilities.[66]

[66] M4-CCC-1

3 RETURN ON EQUITY

3.1 ***OEB Staff's Triangulation Approach***

3.1.1 With the exception of removing the flotation cost premium, OEB Staff proposes that the OEB set the base ROE using "triangulation," effectively averaging the expert proposals.[67] They argue that "[i]t is neither necessary nor advisable for the OEB to pick one of the four expert recommendations in this case, or to make a finding on which methodology (e.g., CAPM, DCF or ERP) or which inputs are superior."[68] OEB Staff points to the 2009 Report, where the OEB averaged five expert recommendations to determine the base ROE, suggesting that a "broadly similar approach would be appropriate in this proceeding."[69] They propose a base ROE between 8.79% (based on a composite average of expert recommendations minus flotation premiums where applicable)[70] and 9.32% (based on a straight average minus flotation premiums where applicable).[71]

3.1.2 SEC strongly disagrees with this approach. OEB Staff's triangulation method undermines the purpose of the hearing process by uncritically averaging results. Significant time and effort have been invested in exposing fundamental flaws in the various expert approaches, and the OEB should make decisions on these issues, rather than avoiding them through averaging.

3.1.3 LEI's comments about the use of multiple models are equally applicable to multiple experts, "using multiple methodologies with unrealistic assumptions will not reduce uncertainties in estimating the ROE" and "it will add more noise to the data thereby obscuring a more reasonable and realistic ROE estimate."[72] Concentric's and Nexus's ROE models are flawed, relying on unrealistic forecasts and inappropriate comparators. Including these flawed models in any average does not yield an ROE that meets the FRS, which must balance fairness to both utilities and customers.

3.1.4 SEC is not suggesting that the OEB must identify the single most appropriate model or inputs. However, it should not throw up its arms and recommend an ROE that ignores

[67] OEB Staff Submissions, p.17

[68] OEB Staff Submissions, p.17

[69] OEB Staff Submissions, p.17

[70] OEB Staff Submissions, p.18-19, see fn 84 and 85

[71] OEB Staff Submissions, p.19

[72] M1-0-SEC-3, p.2

the concerns raised by the parties, as OEB Staff has done. Apart from the issue of flotation costs, OEB Staff does not address any of the substantive critiques experts raised about one another's approaches, or other parties elicited during the hearing, in their actual ROE recommendation.

3.1.5 OEB Staff's approach also sets a problematic precedent for future ROE reviews. It incentivizes parties to retain experts who propose increasingly divergent ROEs from the status quo, influencing outcomes if the OEB merely averages the results. This is particularly unfair to ratepayer groups, which have access to a smaller pool of experts. It also risks excluding alternative approaches, such as those presented by SEC in its Final Argument, which adjust experts' models and data to correct for inappropriate inputs and calculations.

3.1.6 Furthermore, an averaging approach does not make sense in the context of this proceeding where each of the experts' proposed applications of the ROE differ. LEI and Dr. Clearly propose that it be applicable to each utility segment (electricity distribution, transmission, natural gas utilities, and OPG). Concentric proposes that it be applied to all but OPG[73]. Nexus applies theirs only to electricity distribution.[74] The differing applications are important as they impact the experts' models. For example, Concentric did not include any pure or near pure generation utilities[75], whereas Nexus did not include any natural gas utilities[76], in their proxy groups, which have a major impact on their model results.[77]

3.1.7 Even if the OEB considers adopting OEB Staff's triangulation approach, its calculations use incorrect numbers and misinterpret what the OEB did in the 2009 Report.

3.1.8 First, OEB Staff's triangulation calculations incorrectly begins with a base ROE of 11.51% for Concentric, instead of its proposed 10%. This adjustment stems from Concentric's statement that its 10% recommendation was tied to its proposed increase in the deemed equity ratio. If the equity ratios remained unchanged, OEB Staff says Concentric would require a base ROE of between 11.38% and 11.63%, with 11.51% as

[73] M2, p.10

[74] Tr.5, p.3-4

[75] Compare Concentrics's proxy group with LEI's generation proxy group (M1, p.115)

[76] M3, p.61

[77] OEB Staff Submissions, p.15

the midpoint, depending on the utility type.[78]

3.1.9 The OEB should not accept the OEB Staff 're-leverage' adjustment to Concentric's proposal. Concentric's financial models used to calculate its recommended 10% ROE are entirely independent of the proposed capital structure. The proxy group inputs and final outputs are not re-levered to account for differences in equity ratios. If Concentric had assumed the existing equity ratios, its models would still yield a 10% ROE.[79]

3.1.10 OEB Staff also appears to misunderstand how Concentric derived the 11.38% to 11.63% range. These figures were not calculated by leveraging Concentric's recommended 10% ROE to account for differences in equity ratios (40% for electricity distributors and transmitters and 38% for Enbridge). Instead, Concentric used only its CAPM model, re-levering the betas of the proxy group, based on the equity ratios of their underlying operation companies, to reflect the OEB's existing capital structure.[80] This calculation was not intended as an alternative ROE recommendation, but as an illustration of a different CAPM application. Concentric explicitly noted that its ROE recommendation relied on CAPM results that were not adjusted for leverage differences.[81] SEC submits that this approach is further flawed because it assumes that the proxy group companies have the same risk as Ontario utilities, which SEC has demonstrated is incorrect.

3.1.11 Second, OEB Staff does not actually apply what the 2009 Report did. While the OEB averaged the experts' recommendations (which were often averages of different models), it actually averaged the implied (or explicit) Equity Risk Premium ("ERP") recommendations from each expert. Where experts provided a range of results, the OEB used the 'low' end of the range.[82] This was presumably to reflect the lower risk of Ontario utilities. The OEB then added the average ERP to the long-term Government of Canada bond yield to establish the base ROE.[83] OEB Staff notes this in a footnote, but then does not actually apply it in their triangulation approach.[84]

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[78] OEB Staff Submissions, p.18

[79] M2, p.71

[80] M2, p.72

[81] M2, p.72

[82] Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084), December 11, 2009

[83] Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084), December 11, 2009, p.37

[84] OEB Staff Submissions, p.17, fn 78

3.1.12 Both LEI and Nexus provided average, low, and high estimates for ROE recommendations.[85]

3.1.13 If the OEB were to take a simple or composite average of the recommendations (excluding flotation costs) and include the 'low' estimates, as was done in 2009, this would result in a base ROE of 8.58% (simple average) and 8.18% (composite average), based on the original recommendations. Using updated information to the end of September, the results would be 8.50% (simple average) and 8.10% (composite average). Applying the more comprehensive 2009 ERP approach, while removing flotation costs, would yield a base ROE of 8.12% (simple average) and 7.84% (composite average), and using updated September data, 8.10% (simple average) and 7.85% (composite average). SEC believes that composite average is more appropriate as it reflets a balance amongst expert perspectives.

Original Recommendations (Excluding Floatation Costs)					
ROE	**Low**	**Medium**	**High**		**ROE Source**
LEI	8.23%	8.95%	10.22%		M1, p.125
Concentric	9.67%	9.67%	9.67%		M2, p.158, minus 33 bps (Tr.3, p.27)
Nexus	9.86%	10.58%	11.31%		Nexus Table 5, M3, p.40, minus 50 bps
Cleary	6.55%	6.55%	6.55%		M4, p.10
Simple Average	8.58%	8.94%	9.44%		
Composite Avg (Utility Averaged)	8.18%	8.54%	9.09%		
Implied ERP	**Low**	**Medium**	**High**	**RF**	**RF Source**
LEI	5.04%	5.76%	7.03%	3.19%	M1, p.120
Concentric	5.87%	5.87%	5.87%	3.80%	Avg of US and Cdn risk free rates (M2, p.65)
Nexus	5.80%	6.52%	7.25%	4.06%	M3, p.39
Cleary	3.25%	3.25%	3.25%	3.30%	J5.3
ERP Simple Average	4.99%	5.35%	5.85%		
ERP Composite Avg (Utility Averaged)	4.71%	5.07%	5.61%		
ROE Simple Average (ERP + LEI Updated RF 3.27%)	8.12%	8.62%	9.12%		
ROE Composite Avg (ERP + LEI Updated RF 3.27%)	7.84%	8.20%	8.74%		

[85] See M1, p.125; M2, p.40

Updated Recommendations (Excluding Floatation Costs)								
ROE	**Low**	**Medium**	**High**		**ROE Source**			
LEI	8.16%	8.88%	10.15%		J2.2			
Concentric	9.54%	9.54%	9.54%		J4.8, minus 33 bps (Tr.3, p.27)			
Nexus	9.86%	10.58%	11.31%		J5.2, minus 50 bps			
Cleary	6.45%	6.45%	6.45%		J5.3, minus 50 bps			
Simple Average	8.50%	8.86%	9.36%					
Composite Avg (Utility Averaged)	8.10%	8.46%	9.01%					
Implied ERP	**Low**	**Medium**	**High**	**RF**	**RF Source**			
LEI	5.03%	5.75%	7.02%	3.13%	J2.2			
Concentric	5.76%	5.76%	5.76%	3.79%	Avg of US and Cdn risk free rates (J4.8, Attach 1)			
Nexus	5.80%	6.52%	7.25%	4.06%	M3, p.39			
Cleary	3.32%	3.32%	3.32%	3.13%	J5.3			
ERP Simple Average	4.98%	5.34%	5.84%					
ERP Composite Avg (Utility Averaged)	4.71%	5.07%	5.62%					
ROE Simple Average (ERP + LEI Updated RF 3.127%)	8.10%	8.61%	8.96%					
ROE Composite Avg (ERP + LEI Updated RF 3.127%)	7.84%	8.20%	8.74%					

3.1.14 OEB Staff justifies its triangulation approach by claiming that its results align with the status quo, which "has worked well," asserting that "the current ROE is working as intended", and that "[n]o evidence has been provided in this proceeding that Ontario utilities are currently failing to attract capital on reasonable terms, let alone that their financial integrity is compromised."[86]

3.1.15 However, this only demonstrates that the current ROE is not too low. If it were too high, utilities would still attract capital on reasonable terms, and their financial integrity would remain intact. The FRS requires that "utilities must be allowed, over the long run, to earn their cost of capital, no more, no less."[emphasis added][87] The "fair return" must balance fairness to both utilities and their customers. For the same reason, SEC disagrees with APPrO's recommendation to maintain the status quo.[88]

3.1.16 Contrary to OEB Staff's position, evidence indicates that the current ROE is not working as intended, because it is too generous to utilities at the expense of customers. The Price-to-Book ("P/B") ratio of Canadian utility stocks, including Hydro One (with a P/B ratio of 2.04), is well above 1.0, suggesting that utilities are earning returns above

[86] OEB Staff Submissions, p. 20

[87] *Ontario (Energy Board) v. Ontario Power Generation Inc*., 2015 SCC 44, para.76

[88] APPrO Submissions, p.2

what can be considered a "fair return."[89] Additionally, electricity distributors' actual equity ratios are on average higher than the deemed ratio[90], showing that shareholders are satisfied to some degree with receiving lower actual returns than they could achieve by assuming more debt.

3.1.17 A review of arguably the most similar jurisdiction, Alberta, demonstrates that the OEB's existing ROE is too high. The AUC's recently issued 2025 ROE is 8.97%[91], which similarly includes a 50 bps flotation cost premium[92], is 28 bps lower than the OEB's 2025 ROE.[93]

3.1.18 SEC is also concerned with OEB Staff's position, which acknowledges the possibility that the ROE may be too high, but argues against reducing it due to the "prisoner's dilemma" nature of regulatory decisions.[94] OEB Staff contends that "[u]nilaterally slashing the ROE – even if backed by sound theory – makes it harder to meet the comparable investment test."[95] SEC disagrees and maintains that its proposed ROE, as well as lower proposals from a number of the other consumer group intervenors would meet the comparable investment standard, as demonstrated in these submissions. More importantly, OEB Staff's position risks producing rates that do not meet the FRS. The OEB cannot set an ROE higher than what sound theory supports simply because other regulators, particularly in the U.S., might adopt a different approach in the future. Mr. Goulding, on behalf of LEI, noted that "there is arguably a degree of regulatory capture" by utilities in the U.S.[96] The OEB must, in exercising its statutory jurisdiction, base its ROE decision solely on the evidence before it to ensure that it would lead to rates that are just and reasonable.[97]

3.2 ***CAPM***

3.2.1 SEC continues to strongly support a CAPM model that uses raw, rather than adjusted,

[89] M4, p.107-108

[90] M1, p.97

[91] Alberta Utilities Commission, 2025 Return on Equity (Decision 29586-D01-2024), November 8, 2024, p.1

[92] Alberta Utilities Commission, Determination of the Cost-of-Capital Parameters in 2024 and Beyond (Decision 27084-D02-2023), October 9, 2023, p.31

[93] OEB Letter, 2025 Cost of Capital Parameters (October 31, 2024)

[94] OEB Staff Submissions, p.23

[95] OEB Staff Submissions, p.23

[96] Presentation Day Transcript, p.25

[97] *Ontario Energy Board Act, 1998*, s. 36(2), 78(3), 78.1(5)

betas. The EDA devotes considerable effort to arguing that betas should be adjusted to reflect the "widely-accepted and observable fact that betas will revert towards the mean of 1 over time."[98] Similarly, the OEA supports adjusted betas.[99] While it is true that company betas generally gravitate toward 1.0, the evidence does not support this for *utility* betas. Dr. Cleary's evidence, based on significant quantitative analysis, appropriately concludes that "the use of traditional adjusted betas is totally inappropriate."[100] This conclusion is supported by academic literature.[101] Similarly, LEI found that there is "[n]o empirical evidence... to justify the argument that the beta for regulated utilities moves towards one over the long term."[102]

3.2.2 Neither the OEA nor the EDA, nor their respective experts, provide evidence specific to utility betas. They primarily cite work by Dr. Blume from the 1970s, which focused on the broader stock market, not utilities.[103] The most recent evidence cited by Concentric, from Professor Fernandez[104], also fails to support their argument, as it only examined 30 companies in the Dow Jones S&P 500, none of which are utilities.[105] In contrast, a study by Professors Michelfelder and Theodossiou specifically on utility betas, found that utility betas do not converge to 1.0. They concluded that "the Blume equation for electric and gas utility betas is not appropriate."[106] SEC agrees with OEB Staff that "it defies logic to presume that utilities, which are inherently lower risk than the typical competitive enterprise, are inching inexorably towards the market-average risk level."[107]

3.2.3 The EDA's support for Nexus's use of U.S. Treasury bonds as the risk-free rate is flawed and should be rejected. EDA argues that the U.S. risk-free rate is appropriate for the North American market because "the law of one price" suggests that within a market, the same good will have a single price regardless of the buyer, and that differences between Canadian and U.S. risk-free rates will converge over time.[108]

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[98] EDA Submissions, para. 51

[99] OEA Submissions, para. 129-136

[100] M4, p.90

[101] M4, Appendix C, p.136

[102] M1-0-SEC-3

[103] M4, Appendix AF, p.47; Tr.3, p.137

[104] M2-10-OEB Staff-13b

[105] See Table 1 in the paper included at Footnote 1 to M2-10-OEB Staff-13b

[106] Undertaking J4.5, Attachment, p.67

[107] OEB Staff Submissions, p.22

[108] EDA Submissions, para. 57

However, this argument does not justify the use of U.S. Treasury bonds over Government of Canada bonds. If convergence occurs, there is no reason to assume it will favor the higher U.S. Treasury bond yields rather than the lower Canadian bond yields.

3.2.4 The purpose of this exercise is to set the ROE for utilities in a Canadian province, Ontario. The OEB should therefore base the CAPM risk-free rate solely on Canadian 30-year Government of Canada bond yields, ideally using the most recent actual yields for accuracy. This approach aligns with the use of the Long Canada Bond Forecast ("LCBF") in the current ROE adjustment formula[109], which no party, including Nexus, has contested. It is also consistent with the OEB's 2009 Report, which calculated the implied ERP using long-term Government of Canada bond yields.[110]

3.2.5 SEC agrees with VECC's submissions that Nexus's approach, including its Market Risk Premium ("MRP") estimate, is inappropriate.[111] A more appropriate approach to forecasting future growth using stock market returns data is to rely on historical market returns over a sufficiently long period. This is especially true given the volatility of year-over-year returns. Concentric itself acknowledged "substantial differences between the historical and forward market risk premiums."[112] Nexus's approach to setting the MRP through its DCF analysis compounds the flaws in its DCF methodology by basing it on an expected market return of 12.89%, which is unreasonably high.[113]

3.2.6 SEC believes that Dr. Cleary's approach, setting the MRP at 5% based on what actual investors expect the market to produce, is the most appropriate. If the OEB chooses to rely on historical market returns to forecast the MRP, it should consider both Canadian and U.S. returns over a sufficiently long period and avoid overemphasizing recent, atypical returns, as LEI appears to have done.[114] Additionally, it must ensure that the historical averages used are accurately determined. Dr. Cleary pointed out that

[109] M1, p.102; Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084), December 11, 2009, p.49

[110] Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084), December 11, 2009, p.37

[111] VECC Submissions, p.48

[112] M2, p.69

[113] M2, p.63

[114] See SEC Final Argument, para 4.2.17

Concentric's MRP calculations appear inflated and inconsistent with recent studies.[115]

3.3 ***DCF***

3.3.1 The most significant flaw in both the Concentric and Nexus DCF models is their reliance on analyst estimates for proxy group company growth forecasts. This results in unrealistic and upwardly biased growth rates, leading to unreasonable ROE forecasts. Concentric's multi-stage DCF model uses analyst growth forecasts of 5.98% for years 1 to 5, transitioning to a long-term nominal GDP growth rate of 3.99% after year 10.[116] Nexus's single-stage DCF model assumes perpetual growth of at least 6.31%.[117] These growth rates are not credible, producing inflated and unreasonable DCF ROE results. Nexus's DCF ROE estimate, before adding 50 bps for flotation costs, was more than *three* standard deviations above the average.[118]

3.3.2 LEI and Dr. Cleary agreed that using earning forecasts from analysts is highly problematic. LEI explained they are "inaccurate, tend to overvalue the cost of equity, and are consistently overly optimistic."[119] Dr. Cleary was more blunt stating, "I criticize the use of sell-side analysts' forecasts because those are inflated… [t]hey are trying to sell products."[120] This view is well-supported by evidence.[121]

3.3.3 The EDA, in trying to defend Nexus's proposal, argues that regulatory changes implemented by the Financial Industry Regulatory Authority ("FINRA") in 2015 requires financial firms to manage conflicts of interest in research to mitigate these risks.[122] However, a recent study found that "FINRA 2241 caused no significant improvement in market quality under each of ten separate objective and systematic metrics (indices of diligence, objectivity, quality, and accuracy by analysts and analyst firms, and six measures of market efficiency)."[123]

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[115] See SEC Final Argument, para 4.2.18

[116] M2, p.61, Table 11 (These referenced growth rates are for the North American Proxy Group)

[117] See Dr. Cleary attempted calculation in M4-0-SEC-83.

[118] M1-0-SEC-3

[119] M1, p.126; See also M1-O-SEC-3

[120] Tr.6, p.73

[121] For example, see all the studies cited in M1, p.126, ft 31; Also see, M4, Appendix BG;

[122] EDA, para 64

[123] Bhattacharya, Rajeev and Gupta, Mahendra R., Impact of Self-Regulation on Quality of Financial Markets (October 29, 2024)

3.3.4 SEC agrees with the OEA that Dr. Cleary's sustainable growth rate of 1.8% is too low, as it would result in a negative growth rate on an inflation-adjusted basis.[124] However, growth rates double the forecasted GDP, as proposed by Concentric and Nexus, are equally unreasonable. SEC believes that using forecasted nominal GDP is the most appropriate method for projecting proxy company growth in a DCF model. This approach, which Concentric itself uses as the long-term growth rate in its model, avoids the pitfalls of relying on "subjective future earnings growth estimates" from analysts.[125] These estimates are systematically biased and do not support the inclusion of the DCF model as part of the ROE forecast.

3.4 ***Risk Premium***

3.4.1 SEC supports Dr. Cleary's Bond Yield Plus Risk Premium ("BYPRP") equity premium methodology. Unlike the approaches used by Concentric and Nexus, it is rooted in market data by adding a risk premium to the long-term bond yield of utilities.[126]

3.4.2 The OEA and EDA criticize the 2.5% equity premium used in this methodology, arguing that its only support comes from a practice question in a CFA textbook.[127] However, the reasonableness of the 2.5% equity premium is not based on the IBM example in the CFA textbook, but rather on the detailed analysis provided in response to interrogatory M4-EDA-5. Dr. Cleary cites seven different sources showing that commonly used risk premiums range from 2% to 5%, with 3.5% as the average.[128] The 3.5% figure is consistent with LEI's finding of a 3.4% premium, when comparing the S&P/TSX Composite Index's average stock returns to average bond yields between 2001 and 2024.[129] Given this average risk premium, Dr. Cleary appropriately concludes that for A-rated utilities, which have significantly lower risk than the average company (as evidenced by their betas being less than half of the market's), a 2.5% premium over their cost of debt is a reasonable estimate of their cost of equity.[130]

3.4.3 Even if the OEB or others have minor qualms with the derivation of the 2.5% risk premium, these concerns pale in comparison to the flaws in the equity premium

[124] OEA Submissions, para 120

[125] M1, p.126

[126] M4, p.105

[127] OEA Submissions, para. 148-157; EDA Submissions, para. 141-143

[128] M4-EDA-5.

[129] M1, p.113

[130] M4-EDA-5

methodologies used by Concentric and Nexus. Their approaches rely on approved regulatory ROEs, making them inherently circular for estimating Ontario utility ROEs. The AUC has criticized this methodology, not only because approved ROEs are not strictly market data, but also because the methodology fails to incorporate observable market data on utilities' credit spreads, which are integral to the BYPRP methodology.[131] Recently, the AUC reaffirmed its rejection of this approach, stating, "the Commission continues to be of the view that the approved ROEs from other jurisdictions are not, strictly speaking, wholly market-based data and therefore, will not place any weight on the results of the government bond risk premium model."[132]

3.4.4 SEC acknowledges that the AUC also rejected Dr. Cleary's methodology, arguing that the 2.5% risk premium is subjective.[133] However, it is unclear whether the AUC had access to the detailed supporting information presented in this proceeding, such as interrogatory response M4-EDA-5. SEC disagrees that Dr. Cleary's risk premium is subjective. Rather, it involves professional judgment in interpreting various studies and research, no different from the myriad of methodological judgments required in every approach undertaken by the experts in this proceeding.

3.5 ***Flotation Costs***

3.5.1 The EDA opposes removing the 50 bps ROE premium for equity transaction costs (flotation costs), despite providing no evidence to support its members' actual flotation costs.[134] EDA's strenuous objection to its removal from the base ROE, in the face of such clear evidence of its inappropriateness, only reinforces Mr. Goudling of LEI's comment that it is no different than "when somebody gives you a gift at the holidays and then snatches it back that you're going to feel as if you lost something."[135] But as he rightly pointed out, "I cannot find under, you know, basic regulatory principles that there is any justification for the 50 bps adder."[136]

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[131] Alberta Utilities Commission, 2018 Generic Cost of Capital (Decision 22570-D01-2018), August 2, 2018, para. 392-393

[132] Alberta Utilities Commission, Determination of the Cost-of-Capital Parameters in 2024 and Beyond (Decision 27084-D02-2023), October 9, 2023, para. 166

[133] Alberta Utilities Commission, Determination of the Cost-of-Capital Parameters in 2024 and Beyond (Decision 27084-D02-2023), October 9, 2023, para. 168

[134] EDA Submissions, para. 36

[135] Tr.1, p.138

[136] Tr.1, p.138

3.5.2 SEC acknowledges that flotation costs represent real, recoverable costs for utilities, but the inclusion of a generic flotation cost premium in the ROE, especially as high as 50 bps, is unreasonable. As detailed in SEC's Final Argument, there has never been a robust empirical basis for the 50 bps figure.[137] Concentric attempted to justify it by referencing a study by Enbridge Inc., which estimated flotation costs at 5% of gross proceeds.[138] However, this would translate to only a 25, not 50 bps ROE premium.[139]

3.5.3 A proper analysis of flotation costs could have been conducted. In its U.S. testimony, Concentric typically provides detailed analyses of actual transactional and issuance costs for companies in its proxy groups.[140] These analyses have recently justified flotation cost adders at or below 2.64%[141], and in some cases as low as 2.39%.[142] Applying this methodology to its North American proxy group used here would result in a flotation cost premium of just 12 bps.[143]

3.5.4 The evidence shows that equity investments in utilities through share issuances, or other equity injections, are rare and infrequent after operations commence.[144] For municipally owned utilities represented by the EDA, the ownership structure raises questions about the applicability of flotation cost estimates based on publicly traded companies. By far the largest portion of flotation costs in public share issuances comes from underwriter fees, a cost that privately held utilities, such as those owned by municipalities or the province, do not incur.[145] Since most Ontario utilities do not raise equity through public markets, and those that do raise it indirectly through their parent companies, it is unfair for all ratepayers to bear a cost as though they did.

3.5.5 SEC proposes a more appropriate approach, establishing a generic deferral account

[137] SEC Final Argument, s. 4.5

[138] M2-10-OEB Staff-16 (K2.6, p.317)

[139] M2-10-OEB Staff-16 (K2.6, p.317)

[140] Tr.3, p.30

[141] Tr.3, p.30. See Direct Testimony of James M. Coyne, on behalf of the Florida Power & Light Company (Florida Public Service Commission Docket No. 20210015-EI), March 21, 2021, p.83 (K2.6, p.267). Underlying calculations set out in Exhibit JMC-10, p.1 (K2.6, p.272)

[142] Tr.3, p.32. See Direct Testimony of James M. Cone, for Duke Energy Carolinas, LLC (Public Service Commission of South Carolina, Docket no. 2023-338-E) January 4, 2024, Exhibit 9, p.1 (K2.6, p.243).

[143] Undertaking J3.3_Attachment 1, Tab 'Flotation Costs Ex. – NA PG'. SEC used 2.64% as the Flotation Cost Percentage, which produces a Flotation Cost Adjustment of 0.12%.

[144] M2-10-SEC-41c, p.8-9 (K2.6, p.294-295)

[145] See analysis in SEC Final Argument, para. 4.5.9

where utilities can record and later seek recovery of actual flotation costs when incurred. The account would not be limited to only legal or financial transaction costs, but could encompass other costs such as the difference between gross and net funds received by the utility.

3.5.6 The EDA makes several new or expanded unfounded arguments in support of retaining the 50 bps premium.

3.5.7 First, it claims that flotation costs must be included in the base ROE because the OEB sets the deemed cost of capital on a generic basis, "not what costs are actually incurred."[146] While SEC agrees that the OEB sets the ROE generically, this does not mean it must include all components generically. For example, the OEB establishes debt costs primarily based on embedded (actual) costs.[147] If flotation costs were included generically, evidence shows they should amount to only a fraction of the current 50 bps.

3.5.8 Second, the EDA argues that removing the 50 bps premium would amount to "effectively confiscating from utilities their as-yet-unrecovered past equity costs."[148] EDA provided no evidence of this, and given how much higher the current premium is than actual flotation costs, it is unlikely to be true.

3.5.9 Third, the EDA references the 2009 Report, where the OEB included the 50 bps flotation cost premium in the base ROE, suggesting the OEB should not, or cannot, deviate from this without justification.[149] Flotation costs were not a focal point of the 2009 consultation. The OEB's only comment was that the selected ERP "includes an implicit 50 basis points for transactional costs."[150] There were no substantial findings on the matter.[151] In this proceeding, the 50 bps premium, much like the base ROE itself, is

[146] EDA Submissions, para. 86

[147] OEA Submissions, para. 63, 71

[148] EDA Submissions, para. 92

[149] EDA Submissions, para. 6,

[150] Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084), December 11, 2009, p.37

[151] It is telling that the best EDA can come up with is that the panel of capital market analysts that have presentations during the consultation "did not oppose the inclusion of the flotation costs adder" (EDA Submissions, para. 93). This is a somewhat more accurate assessment than what the EDA said in its interrogatory responses, where it said that in 2009 the "Board appeared to convene a panel of capital market experts that provided evidence to support the 50 basis point equity flotation cost" (M3-10-OEB Staff-38, K5.1, p.79). The most accurate assessment is that the capital market panel did not opine, nor appear to be asked to even consider the question.

expressly at issue in this proceeding, and the evidence on actual costs (or lack thereof), demonstrates that it cannot be maintained.

3.5.10 Finally, the EDA attempts to distinguish the BCUC's recent decision to exclude flotation costs from the base ROE, arguing that it involved a specific utility (FortisBC), whereas the OEB sets the ROE generically.[152] It is unclear what implications the EDA draws from this distinction. Should flotation costs be litigated individually in each rate case? Unlike the broader cost of equity, flotation costs are observable, and the EDA has provided no evidence of actual flotation costs for its members. A generic 50 bps premium cannot be justified. SEC's deferral account proposal efficiently addresses actual costs on a utility-specific basis, while recognizing that these costs are generally recoverable.

3.5.11 Excluding flotation costs from the generic ROE is also not uncommon. Many U.S. regulators have rejected recovery of flotation cost outright, and others specifically as part of the ROE.[153]

3.5.12 Nexus's approach to including the 50 bps premium is particularly problematic. It applies the premium to all three of its models[154], even though its ERP model already includes flotation costs built into authorized ROEs from other jurisdictions, resulting in explicit double counting. Concentric, in contrast, does not add flotation costs to its equity risk premium model, avoiding this issue.[155]

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[152] EDA Submissions, para. 95-96

[153] See for example, Illinois Commerce Commission, Order, Northern Illinois Gas Company, October 2, 2019, p. 120: "Historically, the Commission rejects flotation cost adjustments unless the utility can show that (1) it incurred the specific amount of flotation costs for which it seeks recovery and (2) the specific flotation costs have not previously been recovered through rates."; Public Service Commission of the State of Montana, Final Order 7860y, NorthWestern Energy, October 27, 2023, para. 59: The Commission is also unpersuaded by NorthWestern's rationale for a 10-basis point addition to ROE for flotation costs….. the Commission is persuaded by intervenors' arguments that flotation costs are not actual "out-of-pocket" costs and the market accounts for flotation costs."; Kentucky Public Service Commission, Order, Case No. 2022-00372, Duke Energy Kentucky Inc., October 12, 2023, para. 41: "The Commission reiterates that it continues to reject the use of flotation cost adjustments, financial risk adjustments and size adjustments in the ROE analyses." Washington Utilities and Transportation Commission, Avista Corporation, Order 07, April 26, 2019, para. 76: "We agree with Mr. Garrett and Mr. Gorman and reject Mr. McKenzie's proposed adjustment for flotation costs as a component of our determination of Avista's authorized ROE. While these costs may be legitimate adjustments made during the underwriting process, we are not persuaded they should be included as a component of Avista's authorized ROE…… We also agree with Mr. Gorman that Mr. McKenzie has failed to demonstrate the level of costs, if any, that Avista actually incurred during the test year, and developed his proposed flotation cost adjustment on information derived from other utilities."

[154] M3, p.40

[155] Tr.3, p.27-28

3.6 ***SEC's Base ROE Proposal Remains Appropriate***

3.6.1 SEC's proposed base ROE of 7.58%, detailed in section 4.6 of its Final Argument, is the most appropriate estimate that satisfies the FRS, and should be applied to electricity distributors, electricity transmitters, and natural gas utilities.

3.6.2 The proposal is based on an average of multiple approaches (CAPM, DCF, and equity premium), uses a proxy group consisting of both Canadian and U.S. companies, and excludes those with generation assets or material unregulated operations (Concentric's North American Combined Proxy Group from Undertaking J4.2). It also addresses specific deficiencies in the inputs. For the equity risk premium approach, the proposal relies on Dr. Cleary's BYPRP methodology, which is far superior to the authorized ROE approaches used by Concentric and Nexus. Additionally, the proposal appropriately excludes flotation costs.

3.6.3 SEC maintains that the ROE and capital structure for OPG should be determined in its next payment amounts proceeding. OPG faces unique risks as the only generator regulated by the OEB, but also benefits from unprecedented regulatory support compared to other OEB regulated utilities and utilities across North America. These unique risks and regulatory protections require a more detailed assessment than has been conducted on a generic basis in this proceeding.

3.7 ***Annual ROE Formula***

3.7.1 The major area of disagreement among the parties on the ROE formula concerns the proposed adjustment factors. The OEA supports its expert, Concentric, in its recommendation of a 0.40 adjustment factor for the LCBF and a 0.33 factor for the utility credit spread, based on a regression analysis comparing U.S. utility approved ROEs with U.S. Treasury 30-year bond yields and utility credit spreads.[156] OEB Staff has accepted Concentric's criticism of LEI's recommended adjustment factors.[157]

3.7.2 SEC continues to support maintaining the current 0.5 adjustment factor for both the LCBF and utility credit spread factors. SEC agrees with OEB Staff that LEI's proposed adjustment factors are too low and suffer from issues raised by Concentric.

[156] OEA Submissions, para. 198

[157] OEB Staff Submissions, para. 29

3.7.3 Concentrics's adjustment factors have their own problems. First, they are based on a regression analysis of U.S. data, including U.S. ROEs, U.S. Treasury long-term bond yields, and utility credit spreads. It provides no analysis of the relationship between Canadian ROEs, Government of Canada bond yields, and Canadian utility credit spreads, which is what is included in the formula.[158] Second, even within the U.S. data, Concentric's regression shows a relatively weak correlation between the variables.[159]

3.7.4 It is unclear how running a regression analysis between these variables and ROEs can provide real precision in determining the appropriate adjustment factor. Regulatory decisions on ROEs are influenced by numerous factors, and while there may be some relationship to bond yields and utility credit spreads, it is not necessarily direct. The range of expert recommendations on the base ROE in this proceeding demonstrates the complexity and variability of these relationships.

3.7.5 SEC agrees with Dr. Cleary's observation that ROEs have not sufficiently declined in response to reductions in government and utility bond yields over the last two decades.[160] OEB Staff's criticism of Dr. Cleary for not observing this through a historical regression analysis misses the point.[161] The inadequacy of ROE reductions in line with declining bond yields suggests a fundamental issue regarding the relationship between the two, and underscores, that relying on historical relationships is unsuitable for determining specific adjustment factors.

3.7.6 The existing 0.50 adjustment factors strike a reasonable balance between ensuring year-over-year stability in the ROE and providing sufficient responsiveness to changes in the LCBF and utility credit spreads.

3.7.7 There is also dispute as to the specific calculation of the LCBF and utility credit spreads. Since those are common to the calculation of the Deemed Long-Term Debt Rate ("DLTDR"), SEC's reply is included in section 4.1.

[158] M2, p.103-104; M4, p.46

[159] Tr.4, p.102; M2, p.106

[160] M4, p.45

[161] OEB Staff Submissions, p.29

4 OTHER ISSUES

4.1 ***Long-Term Debt***

4.1.1 SEC maintains its position, that using the most recent actual 30-year Government of Canada bond yields remains the most accurate way to forecast the LCBF for both setting the DLTDR and as part of the annual ROE formula. The only difference between SEC's recommendation and Dr. Cleary's is that SEC suggests using the average 30-year Government of Canada bond yield over a slightly broader range (e.g., five days) instead of a single day. This would mitigate daily fluctuations that are unrelated to significant macroeconomic factors, such as changes in interest rates.[162]

4.1.2 Dr. Cleary's analysis demonstrated that from 2011 to 2023, using actual 30-year yields for the subsequent period, was more accurate than the existing forecast methodology.[163] Over that 13-year period, the current forecasting method introduced an upward bias of approximately 0.4%.[164]

4.1.3 Incredibly, the OEA argues that this upward bias is not a "compelling reason to alter the current approach."[165] They argue that since the LCBF is part of the forecast for future long-term debt costs then a forecast should be used to estimate it. SEC agrees that the purpose is to forecast the LCBF.[166] The issue is that the evidence shows the most accurate way to do so is to use the prevailing rate, not the current methodology.

4.1.4 In contrast, SEC does not have as strong view on the appropriate length of time to calculate the utility bond yield spread over the LCBF. OEB Staff and the OEA propose changes from the existing 30-day average to 12 months[167] and 90 days[168], respectively, as recommended by their experts.[169] A longer period may be appropriate to reduce natural volatility that is unlikely to persist into the next year. However, lengthening the period could also diminish the impact of market changes that are likely to persist into the next year.

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[162] See SEC Final Argument, para 5.2.6-5.2.7

[163] M4, p.25

[164] M4, p.25

[165] OEA Submissions, para. 77

[166] OEA Submissions, para. 77

[167] OEB Staff Submissions, p.12

[168] OEA Submissions, para. 195

[169] M1, p.93; M2, p.96

4.2 ***Implementation***

4.2.1 SEC submits that changes to the cost of capital components (ROE, DLTDR, and DSTDR) for specific utilities should be implemented in their rates at their next rebasing application, unless the rebasing is for 2025 rates and the adjustment is explicitly permitted under an approved settlement proposal.[170]

4.2.2 SEC recommends this approach, even though it is arguing for a reduction in the cost of capital, because it reflets good rate-setting practice and it is consisted with the OEB's established policies in similar circumstances. For example, when the OEB updated the cost of capital parameters in the 2009 Report, the changes were incorporated into utility rates only through cost of service applications.[171] Similarly, when the OEB last adjusted the default working capital allowance from 13% to 7.5%, a change that, all else being equal, would lower rates, it ordered that, "[c]hanges to working capital allowance costs will be implemented only in cost of service and Custom IR applications unless otherwise determined by the OEB in a prior decision."[172] The rationale was that this approach "will allow for all of a distributor's costs to be considered at the same time.[173] The OEB also noted that it "adopted the same approach when it amended its cost of capital policy in 2009."[174]

4.2.3 The OEA argues that waiting until rebasing would force utilities to continue operating with an ROE that does not meet the FRS.[175] SEC agrees with VECC, that during an IR term or rate plan, "there are likely to be changes to a number of the utility's cost components, with cost of capital only being one of them," and that it should not "be treated any differently than changes in other cost components of the revenue."[176] Changes in costs (or revenues) during an IRM term or rate plan may result in a utility over or under-earning, causing its actual ROE to deviate from the level embedded in rates, which was deemed to meet the FRS. Unless these variances reach +/-300 bps, the OEB does not typically intervene to consider rate adjustments. This approach is

[170] SEC Final Argument, section 6.3

[171] Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084), December 11, 2009, p.61

[172] OEB Letter, Re: Allowance for Working Capital For Electricity Rate Applications (June 3, 2015), p.3

[173] OEB Letter, Re: Allowance for Working Capital For Electricity Rate Applications (June 3, 2015), p.3

[174] OEB Letter, Re: Allowance for Working Capital For Electricity Rate Applications (June 3, 2015), p.3

[175] OEA Submissions, para. 267

[176] VECC Submissions, para. 347

consistent with established jurisprudence, which requires only that utilities be given the opportunity to "over the long run, to earn their cost of capital." [emphasis added][177]

4.2.4 With respect to utilities rebasing for January 1, 2025 rates, if the utility specific OEB decision or approved settlement proposal explicitly provides for the implementation of the outcome of this generic proceeding in 2025 rates, then those impacts should be recorded in the relevant generic variance account.[178] SEC recommends that the OEB require those utilities update their base rates to include any changes as part of their next adjustment process to avoid significant balances (credits or debts) in the variance accounts and minimize intergenerational equity.[179]

4.3 ***CWIP***

4.3.1 Three Fires Group and Minogi Corp. ("TFG/Minogi") have raised concerns that the OEB's CWIP policy acts as a barrier to Indigenous equity participation.[180] Most First Nations must borrow funds to purchase equity in large infrastructure projects, often before construction is completed, and the interest rates on such borrowing are typically higher than the prescribed CWIP rate. Additionally, for large capital projects, it may take several years before construction is completed, during which it is not recovering those costs.[181] To alleviate these barriers, TFG/Minogi propose that the CWIP interest rate be set at the weighted average cost of capital ("WACC")[182] and that concurrent cost recovery be allowed.[183]

4.3.2 This is an important issue, both to facilitate Indigenous participation in energy projects to further reconciliation and respect for Indigenous rights, objectives that SEC strongly supports.

4.3.3 From the OEB's perspective, this issue raises complex questions of ratemaking, regulatory and energy policy, all of which must be balanced while addressing the

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[177] *Ontario (Energy Board) v. Ontario Power Generation Inc*., 2015 SCC 44, para.76, see also para. 16

[178] See OEB Letter, 2025 Cost of Capital Parameters (October 31, 2024), Appendix B; OEB Letter, Re: Updated Inputs to the OEB's Prescribed Interest Rates and Cost of Capital Parameters ((July 26, 2024), Appendix A

[179] This should not be too difficult as it would only require utilities to update their 2025 rate models to establish "new" 2025 rates that it could then use to apply their 2026 IRM or Custom IR rate adjustment parameters to.

[180] Three Fires Group and Minogi Corp, Submissions, para. 151

[181] Three Fires Group and Minogi Corp, Submissions, para. 160-161

[182] Three Fires Group and Minogi Corp, Submissions, para. 158

[183] Three Fires Group and Minogi Corp, Submissions, para. 176

barriers identified by TFG/Minogi. For instance, while TFG/Minogi propose setting the prescribed CWIP rate at WACC to account for higher borrowing costs for First Nations, this is not a traditional cost of capital question, which focuses on the utility's cost of capital rather than that of its shareholders. If an exception is to be made, and that may be warranted, it should be clearly identified and acknowledged as a broader question of regulatory policy.

4.3.4 Similarly, the long-standing principle that ratepayers do not bear costs for physical assets in their rates until those assets are used or useful must be considered.[184] Again, while exceptions to this principle may be justified, not only to encourage Indigenous reconciliation and economic participation, but also to lower project risks to the benefit of customers[185], any change must be carefully designed and implemented.

4.3.5 The concerns raised by TFG/Minogi merit serious attention, but it may be more appropriate to address the specifics through a separate focused process, such as a generic hearing or consultation, specifically aimed at Indigenous participation in electricity system construction and ownership. This would allow the issues to be examined comprehensively while ensuring that ratepayers bear appropriate costs in their rates.

4.3.6 In the interim, the OEB should make clear the importance of these issues, and that utilities or project proponents considering Indigenous ownership can request deviations from the existing policy in rates or leave to construct applications to address any barriers. The OEB would then evaluate such proposals based on their specific merits.

All of which is respectfully submitted.

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[184] *See Decision and Order* (EB-2020-0290), November 15, 2021, p.50-51

[185] See First Nations Major Project Coalition, National Indigenous Electrification Strategy: Strategy to Accelerate Indigenous Ownership of Net Zero Infrastructure in Canada (2024), p.39, 50