ONTARIO ENERGY BOARD

FILE NO.:	**EB-2024-0063**	**Generic Proceeding - Cost of Capital and Other Matters**

VOLUME:	**Presentation Day**	
DATE:	**September 5, 2024**	
BEFORE:	**Michael Janigan**	**Presiding Commissioner**
	Lynne Anderson	**Commissioner**
	Pankaj Sardana	**Commissioner**

EB-2024-0063

THE 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

Presentation Day held in person and by videoconference from 2300 Yonge Street, 25th Floor, Toronto, Ontario, on Thursday, September 5, 2024, commencing at 9:34 a.m.

PRESENTATION DAY

BEFORE:

MICHAEL JANIGAN	Presiding Commissioner
LYNNE ANDERSON	Commissioner
PANKAJ SARDANA	Commissioner

A P P E A R A N C E S

IAN RICHLER	Board Counsel
FIONA O'CONNELL TINA LI KEVIN MANCHERJEE ANTONIO JOHNSON LILLIAN ING	Board Staff

PRESENTERS:

SEAN CLEARY	Association of Major Power Consumers of Ontario (AMPCO)
JAMES COYNE DANIEL DANE JOHN TROGONOSKI	Concentric Energy Advisors
AJ GOULDING AMIT PINJANI SHASHWAT NAYAK	London Economics International (LEI)
RALPH ZARUMBA FRANCIS PAMPUSH	Nexus Economics, for Electricity Distributors' Association (EDA)

PARTICIPANTS:

IAN MONDROW SEAN CLEARY SHELLEY GRICE	Association of Major Power Consumers of Ontario (AMPCO)/ Industrial Gas Users Association (IGUA)
CHRISTINE LONG MICHAEL LISTER ELENA YAMPOLSKY PAUL RAWLING	Alectra Utilities
DT VOLLMER	Caldwell First Nation

A P P E A R A N C E S

TOM LADANYI	Coalition of Concerned Manufacturers and Businesses of Canada (CCMBC), Energy Probe Research Foundation
LAWRIE GLUCK	Consumers Council of Canada (CCC)
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TIM HESSELINK JACYN KOSKI	EPCOR
TRACY REHBERG-RAWLINGSON	Halton Hills Hydro Inc.
YOON KIM KALEB RUCH BRITTANY CALHOUN	Hydro One
KELLY O'NEILL APRIL BARRIE	Hydro Ottawa
RANDY MURPHY	Kingston Hydro Corporation
NICHOLAS DAUBE	Minogi Corp., Three Fires Group (TFG)
VINCE BRESCIA RUTH YORK McCREA	Ontario Energy Association (OEA)

A P P E A R A N C E S

AMY LONG SUZANNE PRESSEAULT	Orangeville Hydro
HERMAN MO STEVE ZEBROWSKI MATT KIRK	Ontario Power Generation (OPG)
BOHDAN DUMKA	Society of United Professionals (SUP)
MARK RUBENSTEIN JAY SHEPHERD	School Energy Coalition (SEC)
AARON BLAZINA	Synergy North Corporation
MARK R. JOHNSON TRACEE COLLINS	Upper Canada Transmission 2, Inc.
MARK GARNER BILL HARPER	Vulnerable Energy Consumers Coalition (VECC)

I N D E X O F P R O C E E D I N G S

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NO UNDERTAKINGS WERE FILED IN THIS PROCEEDING.

Thursday, September 5, 2024

--- On commencing at 9:31 a.m.

MR. JANIGAN: Good morning. Welcome to presentation day. In this proceeding, we are considering the cost of capital and other matters to set rates for electricity transmitters or electricity distributors, natural gas utilities, and rate-regulated electric generators.

My name is Michael Janigan and I will be Presiding Commissioner in this proceeding. With me on this panel is Commissioner Lynne Anderson on my left, and Commissioner Pankaj Sardana on my right.

Before we proceed to the land acknowledgement I would briefly speak to the procedure we hope to follow. We will not take appearances in the usual manner but I will call upon counsel for each of the four parties presenting evidence in turn to introduce their witness or witnesses. The Panel has had the benefit of reviewing the background of each of the four experts and we don't require any further introductory information concerning their qualifications in this proceeding today.

Only the members of the Panel will be providing questions to each witness following their presentation. There will be no affirmation required of the witnesses. However, today's proceeding will be transcribed. To that end, try to please speak clearly and try as much as possible to avoid speaking too quickly to enable the court reporter to transcribe accurately.

This presentation day is being held for the purpose of

clarity, to ensure the Panel understands what each witness is advising and how that conclusion was reached. The Panel will not be testing or challenging the evidence, and the questions asked by the Panel or not asked by the Panel do not necessarily indicate any disposition of a Panel member towards content or conclusions in an expert report.

Can we proceed with the land acknowledgment, please.

LAND ACKNOWLEDGEMENT

MR. JOHNSON: Good morning. The Ontario Energy Board acknowledges that our headquarters in Toronto is located on the traditional territory of many nations including the Mississaugas of the Credit, the Anishinaabeg, the Chippewa, the Haudenosaunee and the Wendat peoples. This area is now home to many diverse First Nations, Inuit and Métis peoples. We also acknowledge that Toronto is covered by Treaty 13 with the Mississaugas of the Credit. We are grateful for the opportunity to gather and work on this land and recognize our shared responsibility to support and be good stewards of it. Thank you.

MR. JANIGAN: Thank you. I would now ask Mr. Richler to present his witnesses for presentation.

MR. RICHLER: Thank you, Commissioner Janigan. Good morning, Panel. My name is Ian Richler. I'm counsel for OEB Staff. If I may, I'll just quickly introduce the other people sitting at the Staff table. To my left, Fiona O'Connell, Tina Li, Antonio Johnson, Kevin Mancherjee, and Lillian Ing behind me. And our witnesses from LEI, to our left, AJ Goulding, president, Amit Pinjani, director, and

Shashwat Nayak, senior consultant.

And before I just hand it over to them, Commissioner Janigan, in your hands, but if you would like, we could mark the presentation that was filed as an exhibit.

MR. JANIGAN: Yes, please.

MR. RICHLER: So, LEI's presentation, we will call that Exhibit KP1.1. And with that, I would turn things over to LEI.

EXHIBIT KP1.1: LEI PRESENTATION

MR. PINJANI: Thank you. Let's share the screen.

LEI PRESENTATION

PRESENTATION BY MR. PINJANI

Good morning, Commissioners. We have organized this presentation in three sections. First is a brief summary of overarching messages and key takeaways. In the second section, we expand upon key areas of differences between LEI's and one or more experts' recommendations. And third is an appendix summarizes LEI's recommendations across the 22 issues. Given the 30-minute time slot, we will focus on the first two areas today. The third section can be reviewed by commissioners later, the contents of which are consistent with the executive summary in the LEI report filed on June 21, 2024.

Going to the next slide. This slide lays out the five key principles underlying LEI's recommendations across the list of issues being discussed in this proceeding. These principles are as follows: meeting the fair return standard;; administrative simplicity, relative to status

quo; transitioning from status quo only if observed benefits are material; fairness and approach to both utilities and consumers; and transparency and predictability.

Overall, LEI has recommended that several aspects of the status quo be retained. A few examples include adjusting the authorized capital structure only when a significant change in risk profile is assessed by the OEB, upon application by relevant parties. Second, ownership structure is not relevant when determining cost of capital parameters. And third, maintaining annual updates for key cost of capital parameters, along with reassessing the cost of capital policy every five years in a process similar to the ongoing proceeding.

Where relevant, LEI has also suggested modifying certain aspects relative to status quo. Examples of such recommendations include introducing proactive impact assessments prior to implementing material regulatory changes, requiring forward cash flow modelling and scenario analysis associated with impact on key credit metrics when proposing a change in authorized capital structure. And replacing the 50 basis points for transaction costs associated with equity issuances with cost based treatment, similar to the BCUC regulatory treatment in their most recent general cost of capital proceeding as of 2023.

Moving to the next slide. This slide presents a few overarching messages that LEI believes are important to state upfront. First, risk is a function of timing and

likelihood of recovery. As such, while energy transition is in process, there is no evidence that energy transition impacts either timing or recovery of cash flows for the regulator utilities, particularly in the upcoming regulatory period. That is 2025 to 2029.

Second, there is no evidence that OEB regulated utilities have been unable to raise capital on reasonable terms.

Third, risk is a function of the activity and not dependent upon the nature of the investor, meaning size, type of organization, or community status are less relevant if within the control of the investor.

Fourth, change in compliance burden associated with LEI recommendations, for example, reporting new debt and equity issuances and mandating cash flow modelling is minimal given such information already exists with the utilities.

Fifth, LEI believes that unique issues associated with First Nations and Indigenous groups are critical, however are best addressed in a separate proceeding. To this end, LEI has previously reviewed case studies associated with First Nations participation in a separate report from 2023.

Sixth, while some experts have emphasized differences between Ontario authorized returns and U.S. authorized returns, it is arguable whether some U.S. regulators are more generous than justified.

Finally, for ROE determination, while LEI believes there is no academic justification averaging multiple

methodologies, we recognize there may be pragmatic reasons for the regulators to do so.

On the top right-hand side of the slide, we explain why LEI's recommendation associated with mandating cash flow modeling for assessment of capital structure is consistent with LEI's views against over-reliance of analyst earnings when determining authorized ROEs. There are a few underlying reasons. First, regulated utilities themselves have more accurate information than analysts. Second, forward cash flow modelling is consistent with analysis that banks would conduct themselves and/or require the utilities to conduct prior to financing. Third, this requirement does not rely on whether external analysts cover a specific company or not. And finally, the objectives are different. That is cash flow modelling is associated with assessment of capital structure, while over-reliance on analyst forecasts is associated with ROE determination.

Moving on to the next section. LEI has expanded upon seven key areas of differences of opinion between LEI's and one or more expert's recommendations. While there are some additional aspects as well, LEI has focused on the most relevant ones for today. These areas include, first, LEI's recommendation associated with mandating scenario analysis for impact on key credit metrics when assessing capital structure. Second, why allowing incremental 50 basis points and authorized ROE for transactions costs associated with equity issuances is not justified.

Third, use of Canadian risk-free rate is consistent with LEI's methodology for estimating market risk premium.

Fourth, why LEI's estimate of MRP or market risk premium is reasonable in light of the information at hand.

Fifth, beta estimation, and why the use of Blume adjustment inflates beta.

Sixth, why utilization of CAPM makes most sense, instead of averaging multiple methodologies.

And seventh, why a comparison between electricity distributors achieved ROE and authorized ROE does not imply increased regulatory risk.

Moving to the next slide, LEI believes forward-looking scenario analysis showing impact on key credit metrics is necessary to provide a full picture to regulators regarding the impact of change and equity thickness proposed by applicants.

Such analysis is also critical for both investors and rating agencies. As discussed briefly earlier, lenders already require such an analysis to be performed by companies prior to closing on lending transactions. Credit rating agency also perform similar analysis when reviewing ratings for companies on a periodic basis.

In an IR response Concentric has acknowledged that cash flow modelling is one of several perspectives that form business and financial risks. While Concentric notes that this is a partial indicator of forward-looking risk that should be factored into equity ratio considerations, LEI believes this is one of the most important elements

that regulators need to consider.

In previous proceedings associated with assessment of capital structure, LEI has performed such analysis, which is kind of shown in the snapshot here on the slide. We believe it would be significantly more efficient if utilities performed such analysis themselves, for evidentiary record in such proceedings.

Moving to the next slide. LEI has recommended replacing the 50 basis points adder for transaction costs associated with equity issuances with cost-based treatment. Equity issuances do not happen with predictable regularity, which makes it appropriate for these costs to be recovered as and when the utility incurs such expenses.

While some jurisdictions have allowed a 50 basis points adder in the past -- sometimes we are referencing to other regulatory decisions -- it is notable that the BCUC predicted the adder in its 2023 generic cost of capital proceeding, stating the following, I quote:

> "The Panel finds that the proposed flotation cost adder is too vague to be a just and reasonable expense recoverable from ratepayers. These expenditures, if and as incurred, can be recovered from the ratepayers following review and approval as part of each utility's revenue requirement process in the normal course."

LEI has not seen any empirical evidence to justify the 50 basis points adder. In LEI's view, such an adder is likely to overcompensate utilities. To Illustrate via an

example, LEI reviewed reported total equity in the rate base from Enbridge Gas between 2019 and 2023, as shown on the graphic here on the slide.

Based on the data reported by Enbridge Gas, LEI estimated new equity added to the rate base in the range of $141 million to $281 million annually over this period. Allowing the 50 basis point transaction cost adder means allowing transactions costs in the range of $24 million to $28 million annually. That is approximately 10 percent to 17 percent of estimated new equity issuances.

There is no evidence to suggest that Enbridge Gas has actually incurred 10 to 17 percent in transaction costs associated with new equity issuances each year.

In fact, an IR response by the OEA states, "Recent research by the Enbridge treasury team found that the average flotation costs for a sample of Canadian and U.S. utilities were equal to slightly more than five percent of gross proceeds." While LEI is not privy to this research, this example illustrates overcompensation.

LEI believes that cost-based treatment as approved by the BCUC makes most sense for such transaction flotation costs.

Moving to the next slide. In determining ROE, via the capital asset pricing model, or CAPM, LEI has selected a risk-free rate utilizing Canadian data that is a long Canada bond forecast, or LCBF.

However, LEI's estimation of market risk premium, or MRP, utilizes U.S. data. To explain this approach, LEI

started out with considering Canadian data for estimating both the risk-free rate and the MRP.

For risk-free rate, the LCBF was considered to be appropriate for multiple reasons. First, Canada and the U.S. have comparable sovereign credit rating, with no relative country-risk premium.

Second, the LCBF term of 30 years is consistent with the long-term nature of assets and liabilities of Ontario utilities.

And third, the current deviation between the U.S. and Canadian 30-year bond yields is unusual, and one of the factors driving the difference is timing, or example, with the Bank of Canada reducing benchmark interest rates sooner than the U.S. Federal Reserve.

It is notable that the last 30-year average difference between U.S. and Canadian 30-year bond yield is insignificant, as observed by the graphic on this slide.

With regards to the MRP, LEI initially considered the TSX total returns index. The MRP based on this index resulted in 2.81 percent, which in LEI's opinion is inconsistent with investors' risk premium and return requirement expectations.

Investors are likely to consider their MRP opportunity cost based on the U.S.-Canada integrated capital markets. However, LEI does not see any compelling reason to reject the LCBF as an appropriate proxy for risk-free rate, given the same investors that would reject the low MRP based on TSX index would accept LCBF as the relevant risk-free rate.

Moving to the next slide. LEI has recommended an average market risk premium of 8.32 percent based on reviewing the last 30-year market data, that is, data for S&P 500 total returns, minus U.S. 30-year treasury bond yields.

For MRP, there are reasonable justifications to consider the 10-year, 20-year and 30-year market data. These include the following: First, the investor expectations of MRP for the next five years are likely to be shaped by the high market returns observed in the last 10 to 15 years.

It is notable that the total annual market returns, including dividends, for S&P 500 have exceeded 13 percent in nine years out of 15 years since 2009. That is annual market returns have exceeded 13 percent in approximately 60 percent of the time, since 2009.

Second, while the recent market data is certainly important to consider, LEI does not believe it makes sense to ignore the data from the 1990s and 2000s. For instance, since 2001, federal reserve policy rates, annual GDP growth rates and unemployment rates align with rates observed in the 1990s and 2000s. As such, LEI believes it is reasonable to consider the 1994 to 2023 period in its MRP estimate.

Moving to the next slide. To estimate the beta, LEI utilized a three-step process. First, LEI populated the raw data for peer companies.

Second, the raw betas were un-levered using the

operating -leverage of each of the peer companies, which was done to diversify away the firm-specific unsystematic risk.

And third, the average un-levered beta of the peer group was re-levered, using the OEB-allowed deemed capital structure. This is a reasonable approach, as un-levering beta removes the impact of a peer company's debt, theoretically isolating the business risk from financial risk. This gives a clearer picture of the inherent risk of the company's operations and allows for a fairer comparison between companies with different capital structures.

Further, re-levering beta adjusts the un-levered beta to deflect the company's actual or target capital structure.

LEI believes that Blume adjustment is not required, particularly for regulated utility sectors because of the following reasons:

First, no empirical evidence is presented to justify the argument that the beta for regulated utilities moves towards 1.0 over the long term. In fact, the observed average beta between 1968 and 2023 for regulated electricity utilities is 0.49, as shown in the graphic here on the slide.

Second, the weights applied in the Blume adjustment, that is, two-thirds weight towards raw beta, and one-third weight towards 1.0, are typically justified by citing a study from June 1975, which states, and I quote:

"Companies of extreme risk, either high or low,

tend to have less extreme risk characteristics over time."

In LEI's view, the regulated utility sector cannot be classified as extreme risk, either low or high.

Finally, in an IR response, OEA refers to studies by Professor Fernandez between 2009 and 2023, which compare the actual stock returns of 30 Dow Jones industrial companies against the returns of S&P 500, and concludes that beta of 1.0 is a superior estimate for all companies, except two.

LEI notes that none of the 30 Dow Jones industrial companies are regulated utilities and all reflect the risk attributes of regulated utilities. As such, LEI believes that the Blume adjustment for regulated utilities results in inflated best beta estimates by arbitrarily adjusting the beta towards one.

Moving to the next slide. LEI has recommended that the ROE to be determined utilizing CAPM only. Using multiple methodologies does not necessarily result in superior ROE estimates. There are a few reasons for this assertion. First, CAPM with reasonable beta and market risk premium inputs sufficiently accounts for real world uncertainty. Second, CAPM is a flexible model. If a risk is not accounted for in the standard CAPM model, for example Country Risk Premium, there are well established methodologies to just the standard model.

Third, CAPM is the most widely used method to determine ROE. Dr. Cleary, for example, notes in his

evidence that CAPM is more heavily relied upon in practice due to its conceptual advantages. It is also notable that regulators in many advanced international jurisdictions, such as the UK and Australia, use only CAPM to determine the appropriate ROE. Using multiple methodologies with unrealistic assumptions will not reduce the uncertainties in estimating the ROE. On the other hand, such a method can add more noise to the data, thereby obscuring a more reasonable and realistic ROE estimate.

Finally, circularity is another concern. For example, the risk premium approach utilizes already approved ROEs as a key variable in determining an appropriate measure for approved ROEs.

Moving to the next slide. LEI believes that the discounted cash flow or DCF methodology is unsuitable for the determination of ROE. This is for multiple reasons. First, the DCF method's reliance upon estimates of future growth of cash flows is a key weakness. Analysts' earnings forecasts tend to overvalue the cost of equity and are consistently over-optimistic. And second, when valuing a company or an asset to using DCF methodology, a terminal value is frequently considered to capture the value of a business beyond the prediction period, which is typically 10 to 30 years as using a steady state growth over the long-term. As such, DCF methodology is poorly suited for ROE determination using only a 5-year forward-looking outlook and is likely to result in an unrepresentative estimate of the ROE.

Even in this proceeding, the ROE estimates using the DCF model, that is 10.77 percent by LEI, 10.92 percent by Nexus and 11.09 percent by Concentric, are approximately three standard deviations above the average ROE authorized by North American regulators. This implies a probability of less than 0.15 percent in a normal distribution. Overall, the DCF methodology typically tends to push up the ROE estimates relative to just and reasonable returns.

Moving to the final slide, I believe. The purpose of this slide is to emphasize that underachievement of ROEs relative to authorized ROEs does not imply increased regulatory risk. It is not prudent to conclude from the available data associated with achieved ROEs for electricity distributors that Ontario's regulatory mechanisms have not reduced risk.

A few noteworthy points need to be made. First, since 2015, the achieved ROE for electricity distributors has been generally stable, ranging between approximately 8 percent to 9 percent, other than in 2020, which was impacted primarily because of COVID-19.

Second, while several distributors on average have under-earned relative to deemed ROE, between 2015 and 2022, multiple distributors on average have over-earned as well. This can be observed by the chart on the bottom right-hand side of the slide. Dr. Cleary also points out in an IR response that the largest Ontario distributor, Hydro One, which accounts for approximately a third of all Ontario distribution, earned above its allowed ROE every year over

the 2019 to 2023 period, with an average earned above allowed ROE of 1.17 percent between 2018 and 2023.

LEI notes that if certain distributors consistently under-earn, setting a higher authorized ROE would not resolve the underlying reasons for achieved ROE levels. If there is reasonable evidence that there has been a significant change in the risk profile, the option exists to apply for an assessment of their equity thickness via an application to the OEB. I believe that's it. Thank you, all.

This concludes our presentation for today. Thank you for your attention.

MR. JANIGAN: Thank you, Mr. Pinjani. I'll ask members of the Panel if they have any questions of LEI on this matter.

QUESTIONS BY THE BOARD

MS. ANDERSON: I do, and I'm trying to decide whether they cross over into what we'll talk about at the oral hearing. I mean, there's a couple things. One, you've mentioned certain compliance things that you're recommending certain filings. So, what are you anticipating that we do with those filings if every utility is filing every time they issue debt, that kind of thing? Are you envisioning that's just part of our annual review or our regular review of cost of capital or -- so what are you thinking? Because when something gets filed, we only want it filed if we're going to do something with it.

MR. GOULDING: Do I need to push a button? Apologies.

I think that position is certainly in accord with ours of only imposing an administrative burden when there is a value to doing it. I think our starting point was that this would be an annual filing that's only triggered if there's an actual issuance. And the reason for doing so is to have actual data that allows for a check against the inputs that are being used in the generic cost of capital.

And so, it's not meant to be a mindless filing. It's also not meant to be a difficult filing in the sense that this is information that would already be included in a utilities financial reports. I mean, I'm anticipating it's, you know, one page, effectively. It's not new information that has to be processed. So, from that perspective, the idea is, okay, you know, are we seeing trends in issuance costs increasing? Right?

And while, you know, obviously our preference is that issuance costs be incorporated into the overall revenue requirement, having some understanding of whether, and we don't believe this is going to be the case, you know, whether there is some kind of a perverse incentive that issuance costs are going to rise because utilities aren't going to be paying attention to getting competitive quotes, I really don't believe that that's going to be the case, but it can give a sense of whether the market is moving faster in a different direction than the adjustment mechanisms that are built into the framework can cope with. So, it's not meant to be anything, you know, terribly obtuse. Right? It's meant to be a check that says, okay,

you know, this is the way that the formula works. Here is some actual data and let's just be mindful. Is there a problem or not? And my anticipation is that in most circumstances, in most scenarios of market conditions, this is just going to reaffirm that there isn't a disconnect.

But we think, particularly because of the diversity in the degree of publicly available information from the various utilities, this would give the OEB some additional inputs. And if those filings need to be confidential, they certainly can be.

MS. ANDERSON: Okay. Thank you. Since you're talking about the issuance costs or transactions costs, and so, yes. Your recommendation that it be part of the revenue requirement instead of part of, I guess, the debt, and I know that will be a subject at the oral hearing, but first of all, just on the math basis, can you help me understand the translation between the 15 to 17 percent that you come up with to the 50 basis points, just a high level?

MR. PINJANI: So, just to cover that point, we're not able to come up with that math. So the 10 to 17 percent is our estimate of what was allowed, because of 50 basis points adder. So, if you take the 50 basis points and multiply that by the ROE allowed in that period, that gets you that 14 -- the dollar number. And you divide the dollar number by the total issuance. And that's how you get the 14 to 17 percent.

MS. ANDERSON: Right. And then you compared that with actual costs?

MR. PINJANI: We don't know the actual costs.

MS. ANDERSON: You don't know the actual costs. Got it.

MR. PINJANI: What we only know is a statement in IR response, saying that these costs are around five percent.

MS. ANDERSON: Right. And so I know you are not the only ones that have suggested the 50 basis points was high; others think it's fine. But did you consider just a proposal that would simply lower the 50 basis points and include it in that interest cost? Or you just thought this was a cleaner approach of getting to the actual cost?

MR. PINJANI: In my personal view, it's a cleaner approach to do this on a revenue requirement, because they can be infrequent as well, so even if you lower the number to, let's say, 25 basis points.

MS. ANDERSON: And then were you envisioning that there would be a deferral account, or something to record it in, if this happens in the middle of a term, so that then it would be -- that would be recovered at the time of rebasing? Is that what you were thinking?

MR. PINJANI: Yes.

MS. ANDERSON: Okay. Thank you. The other question, and it's probably one that might come up with the other presentations, as well, and, you know, there's peer companies that are picked out to do the analysis. And I often wonder when I look at the Ontario sector, we are setting this cost of capital for 70-some odd utilities. You know, they range from a few -- well, we've got about

eight, seven or eight that have less than 5,000 customers. We have, you know, several that are over a million.

And so, do all of these proposals that you have work for the little guys and the big guys? I mean, I think we often, when we are looking at this, we are talking about debt issuers, but many of ours have, you know, debt with their municipality. Most of the utilities are government owned. So do all your proposals work when I'm looking at, you know, the range from those with 3,000 customers to those with over a million?

MR. GOULDING: I think the underlying policy question would be is it appropriate were the customers of a utility with 3,000 customers to pay more because that utility has not consolidated, or not?

What we have tended to do is to take the position that, overall, risk is determined by the activity, and that all of these utilities are engaged in similar activities.

Now, in addition, because there are some aspects of the cost of capital framework that are based on actuals, up to a deemed cap, right? There is some variation for the fact that if you are a 3,000-customer utility and you are raising funds, it's going to cost you more on a percentage basis. Right? Your interest rate is likely going to be a little bit higher, and so forth, just because of the small quantity of funds that you are raising.

So, I think that there's a balance. And some of these questions you can address with financial theory. Others are a matter of policy. And what we have tried to say is

if your policy is that we are not going to reward being small, right? That that's a choice that the municipalities themselves make, and they may have good reasons for doing so. That, in that particular case, allocating them a higher return on equity isn't a just and reasonable outcome. But your policy objectives may well lead you to different conclusions, depending on what you want to incentivize.

MS. ANDERSON: So it's not an economic question, it's a policy question more than --

MR. GOULDING: Yeah. I would say it's only partially an economic question. I mean, financial theory would say we focus on the risks of the activity, and that's what we compensate.

But, from a policy perspective, if we want to say, look, we really like having municipal control and having utilities that are hyper-responsive to local needs, and so we are going to give them a little bit more on their return on equity, then that objective isn't really a financial objective. That's a social objective.

MS. ANDERSON: Thank you. And just moving on, just a clarification on the cash flow modelling that you have talked about, your proposal is only when someone is looking to move from a deemed capital structure? So, you are still proposing that there be some kind of deemed capital structure. And then -- but if you want to move from it, then you have to -- then you propose they do cash flow modelling? Do I have that correct?

MR. GOULDING: Yes. I would state it slightly differently, and my colleague Mr. Pinjani can step in at any time if I give a view different from his. But what we are talking there is really about the equity thickness. Right.

MS. ANDERSON: Yes.

MR. GOULDING: And so, at any time, a utility can come in and say, my risks are very, very different. and I believe that I require more equity to compensate for those risks. And a proceeding can be started.

And I think that gets back to the fact that this framework has both generic and utility-specific aspects that help serve as shock absorbers, if you will, if indeed there are some unique aspects that can be tested that would justify a different equity thickness for a particular utility.

MS. ANDERSON: Right. So, for instance, if we establish a certain equity thickness that is generally applicable, and someone wants something different, then you can come in with your cash flow analysis?

MR. GOULDING: Yes, that's correct.

MS. ANDERSON: Okay. And then I guess my last question: Obviously, there are a lot of comparisons to the States. You've picked some Canadian data, as well. I think it's probably generally correct to say that most of the utilities in the States, or at least many of them, are privately owned. Many here in Ontario are government owned. Does that make any difference to you?

MR. GOULDING: So I think when we think about Ontario utilities, they are government-owned, but they are corporatized. So, in theory, they are acting like, you know, any Ontario commercial entity that is a for-profit entity. They just happen to have a non-profit shareholder.

So while in the U.S., depending on your metric in terms of customers or assets, approximately maybe 70 percent of customers are served by investor-owned utilities -- subject to check, but I think I'm in the right ballpark. I think that the right benchmark, I wouldn't want to go in and try and look at co-ops, for example, in the U.S., which have a completely different regulatory structure, or municipal utilities in the U.S., generally regulated by council. The Ontario framework of having an economic regulator is consistent with the framework that those comparators face.

Now there are differences in terms of the application of PBR, whether or not a market is liberalized. So there are definitely differences that are reflected in the different choices that various experts make in terms of comparators.

But I think that fundamentally, because Ontario utilities are themselves for-profit entities, that I would not critique the use of comparators that are investor-owned utilities. I think that is the right approach.

MS. ANDERSON: Okay. Thank you. Those are my questions.

MR. JANIGAN: Thanks, very much. I have a question

that follows up on your observation that the regulatory treatment in terms of rates in the United States tends to be more generous than that of regulators in Canada. And I may have missed this in the evidence, but your conclusion is based on a general review of the data? Or is there specific data that you have referenced in relation to making that comparison?

MR. GOULDING: So, I'll leave Mr. Pinjani to supplement, but I think we have referenced ROEs in our work and we've also responded to some IRs in that regard. And so, I think there's probably broad agreement amongst the experts that the ROEs in Ontario are on the low end, as noted, there are challenges in pulling together comparators. We have chosen to use pure plays and then create a synthetic vertically integrated Ontario utility. An alternative as we mentioned is to look only at vertically integrated utilities. But nonetheless, I believe the data is both in our report and certainly other experts have provided different views, but some similar data.

MR. PINJANI: And I think it's to do with not just the ROE, but also capital. On both sides, you'll see that observed data shows that U.S. in general has a higher average authorized equity thickness as well as higher average ROE.

MR. JANIGAN: Now, do you expect if the OEB adopted your recommendations that those rates would move closer together or would stay pretty much the same in terms of

difference?

MR. GOULDING: I mean, that's partially a question to the periodicity of rate cases in the sense that, you know, not every utility in the U.S. goes for a rate case every year. Now, given that many utilities are arguing for substantial increases in capital investment, we are seeing more rate cases more frequently. So, I think that in the U.S., you still have affordability concerns and you have the potential for declining rates, so I would not say that I would expect convergence to Ontario levels, but that I would expect that the jurisdictions that are currently similar in terms of the allowed returns in the U.S. will continue to be similar to Ontario.

So, I'm not expecting a broad divergence among those that are close. The challenge is in, let's say jurisdictions with special risks, California. Right? So, California has a unique wildfire liability regime that results in a different risk profile. They have kind of worked that out a little bit, so maybe the allowed returns are eventually going to fall because there's a different kind of insurance coverage.

But the other thing that we see in the U.S. is that there is arguably a degree of regulatory capture. Right? You have utilities like Georgia Power that serve the bulk of the state, that serve both electric and gas that have nurtured relationships with their regulators for decades, and until something goes wrong, and even Plant Vogtle didn't disrupt the relationship between Georgia Power and

its regulators, I would expect those jurisdictions are going to be a little bit more on the higher side in terms of allowed returns.

MR. JANIGAN: Okay. Thank you very much. Those are all the panel's questions. Perhaps we could have the next panel seated. I believe Mr. Smith --

MR. SMITH: Yes. Good morning, Commissioners. Pleasure to see everyone. Yes, we have -- it's Crawford Smith on behalf of the OEA.

MR. JANIGAN: Well, we'll have two or three minutes here to sort of change the guard.

MR. SMITH: Sort it out. I'll just ask the folks from Concentric to come forward. And I don't know whether we have name tags for them or not, but that would be great.

MR. JANIGAN: Okay. I think we can commence.

MR. SMITH: Yes, please.

MR. COYNE: I think we're good to go on this end if the Board is?

MR. JANIGAN: Yes, please proceed.

CONCENTRIC PRESENTATION

PRESENTATION BY MR. COYNE

MR. COYNE: Well, good morning, Board members, Staff, and parties to this proceeding. Just to go back to introductions, my name is Jim Coyne and together with my colleagues, Dan Dane to my left and John Trogonoski to my right, we will be presenting the findings and recommendations from our report and study that address the full list of issues identified by the Board in this

proceeding.

In addressing you today, I'm mindful of a similar presentation we gave to this Board 15 years ago in the Board's last major consultation on these issues. And in that presentation we highlighted five major conclusions. The first of those was the current formula does not satisfy the fair return standard. The second was government bond yields do not track equity costs in all market conditions. The third, U.S. utilities and Canadian utilities are comparable. The fourth, the formula needs to be rebased and a new adjustment mechanism adopted. And the fifth, government-owned utilities and investor-owned utilities should receive the same cost of capital.

We were pleased that after deliberations by the Board, the Board concurred on each of these major conclusions and charted a course that we believe has served the Board, the industry, and stakeholders well over the past 15 years.

If we could go ahead the next slide. Then, as today, we believe the industry in its regulation are at an inflection point. In 2009, it was in the wake of the financial crisis and the Great Recession of 2007 and 2008, when capital markets were in turmoil. Today, as I'll discuss in a moment, it's an industry-specific challenge, but our conclusions will reinforce those we reached back in 2009.

Our focus will be on our key findings and recommendations with a slightly deeper dive on the key issues of ROE, equity thickness and carrying costs on

deferral and quick balances. Our presentation materials include an appendix which address each of the 22 issues raised by the Board and contrasts our position with that of the other experts.

If we could go to slide four, please. Thank you. At the outset, I would like to highlight seven key findings and recommendations based on our analysis and broader assessment of Ontario in the context of the North America utilities industry, economy, capital markets and the regulatory environment.

First, as I mentioned, the OEB is investigating the cost of capital and inflection point. There is no better way to describe this than the words of the credit rating agency, DBRS Morningstar, where they state:

> "The industry's ongoing allocation of substantial capital towards initiatives such as climate adaptation, modernization and energy transition has reached unprecedented levels, with many utilities rolling out capital expenditure programs that are 10 percent to 20 percent greater compared with previous cycles."

So, clearly it's not business as usual. The demands of the industry to meet low growth transition and less reliance on fossil fuels and to modernize the infrastructure will require unprecedented levels of both public and private capital.

Secondly, Ontario utilities raise capital in an integrated North American market in which U.S. and Canadian

utilities are viewed as comparable by investors. We have done considerable research on this topic and now, more than ever, investors see the market for utilities as a North American one.

Thirdly, the current Ontario formula ROE of 9.21 percent and equity ratios of 36 to 40 percent are insufficient to meet the requirements of the fair return standard. Business risks have increased, as have capital costs for utilities. While the Board's existing formula has worked as designed, it is not current meeting the fair return standard for Ontario's electric distributors, transmitters, and gas distributors.

Our analysis shows that an ROE of 10 percent and a minimum equity ratio of 45 percent will satisfy the requirements of the fair return standard and allow Ontario's utilities, excluding OPG, to effectively compete for capital with their North American peers over the coming years.

Fifth, we also conclude that Ontario utilities are not recovering their full cost of capital through deferral and variance accounts and on CWIP. Our recommendations address this imbalance.

Sixth, a cap on debt costs, as proposed by some experts, would not fully recover the prudently incurred cost of debt for all Ontario utilities.

And finally, taken together, our recommendations will provide continued access to capital at reasonable rates and financial flexibility for Ontario's utilities to meet the

current and foreseeable challenges facing the industry.

Next slide, please. One cannot discuss the cost of capital, of course, without recognizing the legal requirement of meeting the fair return standard. Emphasizing the importance of this point, the Supreme Court of Canada summarized in a 2015 decision, and I quote the Supreme Court:

> "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 not be able to expand its operations or even maintain existing ones. This will harm not only its shareholders, but also its customers."

It's important to recognize that the fair return standard encompasses both the ROE and the capital structure. While all the experts recognize the fair return standard, we believe it's important to understand it is a three-pronged test, and this Board was very clear in its 2009 report when it indicated that, and I quote the Board:

> "The Board agrees with the comments made to the effect that the cost of capital must satisfy all three requirements which can be measured through specific tests, and that focusing on meeting the financial integrity and capital attraction tests without giving adequate consideration to

comparability test is not sufficient to meet the fair return standard."

We do not believe that all the experts in this proceeding adhere to that standard established by this Board in consideration of its legal requirement.

Next slide, please. We recognize that while this Board has a legal requirement to set the cost of capital to meet the fair return standard, it also has a broad responsibility to serve the public interest. While these might be thought of as in conflict, in fact, they are compatible.

It's a difficult decision for any board to approve an increase in consumer costs, which would occur if the Board follows our recommendations, unless it also believes it is acting in the public interest.

Let me explain why we believe our recommendations are aligned with the public interest. Our recommendations would accomplish the following things: one, provide a solid financial foundation for Ontario's utilities; two, will allow Ontario's utilities to compete for capital on favourable terms with their North American peers over the coming years; three, assure that Ontario's utilities will have the resources required to meet the current and foreseeable challenges facing the industry; fourth, recognize that Ontario operates in a North American economy, a North American utilities industry and North American capital markets.

The balance of interest between consumers and

shareholders who require a compensatory return are met by these recommendations.

To drive home this point, the next slide, please: I would just like to cite two reports that were just released over the course of the past week. A study just released by the management consulting firm, McKinsey, in a decision by the Massachusetts Department of Public Utilities underscore these points of alignment. McKinsey points out that while significant progress has been made over the past 15 years, there is a gap in deploying renewable energy technologies that would achieve public policy goals in energy transition. And they go on to cite all the reasons why that gap exists. But financing the projects necessary to achieve these goals is key among them.

And the Massachusetts utility regulator, in approving electric sector modernization plans just this past week, found that these investments would ultimately provide net benefits to consumers.

So this is the context of the inflection point that we mentioned. Substantial new investments are required in each segment of the industry and unprecedented levels of capital from both public and private sources will be required to meet common public policy goals in Canada, in the U.S. and globally.

Providing the appropriate returns to public and private investors is in the public interest, and recognizes the importance of meeting these goals.

Next slide, please. Let me now turn to the return on

equity. The next slide, please. One back. Thank you.

Concentric recommends a base ROE of 10 percent for Ontario's regulated electric and gas distributors and transmitters. We arrive at this recommendation with the perspectives of multiple models and multiple proxy groups, and also relying on our experience using these models extensively before regulators both in Canada and the U.S. at both the provincial, state and federal levels.

Our observation is that no proxy group or model is perfect, but you can see the range of estimates here is fairly tight, between 9.36 and 10.62 percent, and converges around 10 percent, which is the basis of our recommendation.

Based on our analysis, we are confidence that this ROE and recommended minimum equity ratio will satisfy the three tests of the fair return standard.

The way to meet the fair return standard and balance the interests of consumers is not to take away any aspect of the fair return standard, but to adopt a conservative approach in meeting them, as we have in our analysis.

Next slide, please. Contrasting our recommended ROE with those of the other experts, there is a surprisingly wide range, from 7.05 percent to 11.08 percent. To understand these differences, you need to examine the proxy group selected, the models employed, the inputs to those models and the reasonableness of the result. This is a challenge within our allotted time, so I will hit some key points.

Next slide, please. Similar to our analysis, and I will begin with Nexus here, Nexus also uses multiple models and a North American proxy group, but appears to assume the existing 40 percent equity ratio in its analysis and the 11.08 percent recommended base ROE. Because Nexus accounts for financial leverage in its analysis, we assume that their recommendation would be much closer to our 10 percent if they had assumed our recommended 45 percent equity ratio, but I would defer to Nexus to comment on that.

Let me turn to LEI. LEI recommends, as we just heard, resetting the base ROE to 8.95 percent within a range from 8.2 to 10.22 percent. We point out several areas of disagreement between our approach and LEI's in our report. Among them, Concentric disagrees with the following aspects of LEI's analysis. One, primary reliance on a single model to estimate the authorized ROE rather than multiple methodologies. Two, certain inputs to the CAPM analysis, including LEI's use of raw betas rather than Blume adjusted betas and also the level of the market risk premium employed. We disagree with LEI's concerns with the DCF model to estimate the cost of equity for regulated utilities, and the exclusion of an adjustment for flotation costs and financial flexibility, which is a departure from the OEB's past practice of allowing an adjust for 50 basis points. However, if LEI were to adopt its alternative number 6 presented in its report where it averages the results of all three models, the DCF, the CAPM and the risk premium, and include the 50 basis bullet point adjustment,

LEI's base ROE would be 9.79 percent, very close to our 10 percent.

Turning our attention to Dr. Cleary, his use of a small Canadian proxy group and his judgments concerning model inputs yield an untenable result. Dr. Cleary's recommendations of 7.05 percent is 145 basis points below the lowest authorized return for any other Canadian utility and does not meet the requirements of the fair return standard on that basis alone. Unless he could somehow demonstrate that Ontario's utilities were of a completely different risk class, which he has not done.

Let me now turn to my colleague Mr. Trogonoski, who will elaborate on the North American perspective of utility investors and our specific recommendations to adjustments on the ROE formula. Next slide, please.

PRESENTATION BY MR. TROGONOSKI

MR. TROGONOSKI: Thank you, Mr. Coyne, and good morning, Panel members. It's a pleasure to be here with you again this morning. I would like to talk briefly about the North American perspective and the importance of that viewpoint. The Board was really a leader in 2009 when it recognized the value of including both Canadian and U.S. companies in the proxy group for purposes of establishing the cost of capital for Ontario utilities. And whenever we talk with equity investors or equity analysts or credit rating analysts about their views, we repeatedly hear from them how they consider the utility industry to be a North American industry.

And this is really a critical point, because it means that Canadian companies are competing for capital with similar risk companies in both Canada and the U.S. So, if Ontario utilities have a lower authorized ROE or a lower deemed equity ratio than their North American peers of comparable risk, it places them at a disadvantage in competing for capital at a time when significant investment is required in the industry. And it's important to go back to the fair return standard here and remember that it requires the return, and the return includes both the ROE and the deemed equity ratio, that return must be comparable to that available to investors in companies with similar risk.

And Dr. Cleary is the only expert in this proceeding who limits his analysis to a group of five Canadian utility companies and, by contrast, we believe it's reasonable to include both U.S. companies and Canadian companies because they do have comparable business, operating, and regulatory risk. The industry has seen a number of cross-border investments in the last 20 years, especially with regard to Canadian companies acquiring utilities in the U.S., and we've worked on several of those transactions between U.S. and Canadian investors and the deals are just further market evidence that investors do consider investments on both sides of the border as they assess their alternatives.

Furthermore, we would note that some have questioned on whether Ontario utilities have raised capital in the U.S. market, but that's not really the most important issue

here. What matters more importantly is that investors do have options on both sides of the border, and they are seeking comparable returns on their investments. So, if they can get a higher return in a different company in a different country, they will do that if the risk of those two companies is equivalent.

And finally on this point, I believe the regulators in both British Columbia and Alberta have both recently concluded that using a North American proxy group is their preferred approach and, in particular, the BCUC had a nice summary of this point that we have here on our slide where they say:

"We find that having a proxy group of North American comparators trumps any jurisdictional or structural differences and in making this determination we rely on the fact that financial and capital markets are highly integrated and that utility regulatory regimes in North America are sufficiently similar for the purpose of establish a comparable ROE."

If we can go to the next slide, please. So, here we have a summary for you of the current OEB formula parameters. At the top of the slide and below that are recommended changes to those parameters. And, as you know, there are really four parameters that are included in the formula. We are recommending refinements to certain of those parameters to reflect more recent updated market data and also several modest changes to several of those parameters.

So, the four parameters are the base ROE, which as Mr. Coyne discussed earlier, we recommend be reset at 10 percent. The second parameter is the long Canada bond forecast, or LCBF. The third parameter is the utility credit spread. And the last parameter are the adjustment factors that are used to adjust for changes in government bond yields and utility credit spreads.

So, turning first to the LCBF, similar to the recommendations from LEI, we're also recommending moving to a different source for the long Canada bond forecast. Currently the formula uses a consensus economics forecast of a 10-year bond, and it adds a spread between the 10- and 30-year bond to that forecast to make it a 30-year bond forecast. Our recommendation is to use a 30-year government bond forecast that's available from several major Canadian banks, and this avoids the problem that has occurred in recent years with using the 10/30 spread that has been inverted due to conditions in capital markets during the inflationary period of the last couple of years.

Secondly, turning to the utility credit spread, as we say in our report, this value has been within a fairly narrow range since it was adopted by the Board. So, since 2010 it has ranged from approximately 1.35 up to 1.50 percent. The spread is important, however, because it does reflect the business risk profile of utilities in the debt market, and we recommend updating the value of the spread to reflect current market conditions. As we show there on our slide, it would be approximately 1.41 percent as of the

end of May of 2024.

And finally, with regard to the adjustment factors, we're recommending modest changes to these values to reflect the fact that correlations between authorized ROEs and government bond yields and utility credit spreads have declined to some degree in recent years. In our report, we ran a regression analysis based on the relationship between authorized ROEs and government bond yields and A-rated utility credit spreads, and that regression showed that the adjustment factor for the LCBF should be reduced from the current 0.5 down to 0.4. And for the utility credit spread, the adjustment factor would be reduced from 0.5 down to 0.33.

So, that finishes our summary of the ROE section of our presentation. And back to Mr. Coyne now.

MR. COYNE: Thank you. And Mr. Dane will be completing our discussion by summarizing our recommendations on equity thickness and returns on deferral and variance balances and on CWIP.

PRESENTATION BY MR. DANE

MR. DANE: Good morning. I would like to reiterate that the fair return standard encompasses both the ROE as well as the deemed equity ratio. Ontario uses a generic ROE, as we know, and equity thickness is used to recognize differences in risk. We recommend retaining that model, although we believe that at each rate setting application, an analysis of the comparability of Ontario's equity ratios should be performed, not solely an analysis of whether risk

has changed.

In this proceeding in our assessment of equity thickness, we address two main questions. The first was does the risk ranking as measured by equity ratios continue to be reasonable? And two, do the equity ratios as a class meet the fair return standard and, specifically, the comparable return component of that standard?

To answer both questions, we analyzed several utility risks, including those relating to energy transition, climate risk, cybersecurity risk and regulatory risk. We also reviewed those risks in comparison to our peer groups of North American utilities, finding that, in aggregate, the business risk profiles of the North American proxy groups reflect similar risks to Ontario utilities, except OPG.

And our conclusion is also that the risks for Ontario utilities have increased over time, driven primarily by energy transition, climate and physical risks, as well as cybersecurity risks.

As on example of our analysis, we looked at risks related to the energy transition, which is one of the questions the Board had in its issues list, and which is leading to a transformation of all aspects of the industry. Energy transition creates significant planning risks and capital needs for electric companies, it contributes to OPG's pursuit of highly intensive and first-of-a-kind nuclear projects. And energy transition also means that Ontario's natural gas distributors are facing the prospect

of declining demand and stranded asset risk.

And yet, despite our findings of comparable risks to the peers that we reviewed, as well as increasing risk for Ontario utilities, Ontario's equity thicknesses fall below those of its peers, as shown in this chart. Therefore, we recommend equity ratios be adjusted in this proceeding to address this disparity.

And while arguably, given our conclusions regarding the need to compete for capital across North America, that adjustment could reasonable be made at 50 percent or more. Our recommended 45 percent minimum equity ratio is a conservative measure of equity thickness.

To that point, the 45 percent is the minimum appropriate equity thickness to meet the fair return standard, and it forms on integral part of our recommendations, coupled with our ROE recommendations that my colleagues just discussed.

Can we move to the next slide, please. In terms of the risk ranking of Ontario utilities, which has gas utilities at the bottom of the spectrum, electrics in the middle and OPG as the highest risk segment, we find that natural gas has become riskier than electric distribution, driven primarily by energy transition-related risks.

OPG as the only pure-play regulated generator in North America, with a large nuclear presence, continues to reflect a distinct and elevated level of risk.

And while we find that gas distribution is riskier than electric distribution and transmission, we disagree

with Dr. Cleary's recommendation to reduce Hydro One's equity ratio. This would only exacerbate the equity ratio gap that I discussed on the previous slide, while also sending a negative investment signal at a time of increasing capital needs. And it would also threaten credit deterioration at Hydro One.

Can we move to slide 18, please? I will wrap up with a discussion of carrying costs on deferral and variance accounts, and on construction work in progress, or CWIP. DVAs, as they are called, and CWIP, represent longer term deferrals and delayed recovery of significant costs for utilities. And so, at a fundamental level, a key consideration is that the cost of capital associated with those delays be recovered by the utilities.

And when we are talking about the manner in which utilities finance these deferrals, it's on their balance sheets, which is done with a mix of debt and equity, not purely short-term debt, as is currently assumed in the carrying costs for DVAs, and not purely with long-term debt, as is currently the assumption with CWIP.

In particular, when we look at the capital costs during construction, which is the carrying costs on CWIP, the approach in most jurisdictions in the U.S. and Canada is to apply the weighted average cost of capital or some variant of the weighted average cost of capital, which reflects both debt and equity components, not only a long-term debt rate, as is currently done in Ontario.

And so, we recommend that the weighted average cost of

capital, or WACC, be applied here, allowing that for shorter term deferral in variance accounts, the prescribed interest rate may continue to be reasonable.

Application of the WACC to these accounts provides the opportunity for utilities to recover all costs associated with a utility's invested capital which, as we discussed, is of critical importance at this inflection point for the industry.

That concludes our discussion, our presentation. I will just reiterate that we provided an appendix with our presentation that summarizes the issues, along with areas of alignment and disagreement among experts.

So thank you, and we will take questions.

MR. JANIGAN: Thank you, very much, panel. Mr. Coyne, do you have something to add?

MR. COYNE: No. Just getting ready for your questions.

MR. JANIGAN: Okay. I am sorry. Mr. Sardana.

QUESTIONS BY THE BOARD

MR. SARDANA: Good morning. I just have a couple of questions. Mr. Coyne or Mr. Trogonoski, leaving aside some of the larger Ontario LDCs, in particular Enbridge, how many Ontario LDCs actually compete for capital outside of Canada? I mean, I would even put Hydro One in that situation. Hydro One has issued in the U.S., I believe, but how many Ontario LDCs would practically issue or get money from outside of Canada?

MR. COYNE: I think we answered an IR on that question

and, John, I don't know if you recall better than I do, but we were asked that very question. And my recollection was that there were two or three companies that actually raise debt and/or equity capital cross-border. And...

MR. TROGONOSKI: I believe both Hydro One and Enbridge have issued debt capital in the U.S. And other companies in the Canadian proxy group have as well, including Fortis and AltaGas. So it does happen.

MR. COYNE: Coupled with that point, the one that we wanted to emphasize was that even for companies that aren't issuing capital cross-border, their investors, who we work with -- let's just say Ontario Teachers, for example, or the BC Pension Fund, et cetera, we work with them, looking actively at investments in U.S. utilities as well as Canadian utilities.

So the investors themselves have the option of buying Toronto Hydro debt or buying Southern Company debt or Georgia Power debt. So that's where the market clears, in our view, is at the investor and not necessarily with the utility, although some are raising capital on both sides of the border.

MR. SARDANA: Yes, that's a fair point. But of the companies, the larger utilities, say Toronto Hydro and others, have they had any trouble with their issuances in terms of attracting capital? I mean, most of these issues seem to be well oversubscribed.

MR. COYNE: Not that we are aware of. We have not documented difficulties raising capital. We are aware that

Enbridge at this point in time is on a negative credit watch, so maybe there are concerns there concerning impacts of transition as well as financial leverage.

Our point is not that the companies have had a difficult time raising capital in the past; it's that we're in a new world, and they will be deploying significant amounts of capital to meet the challenges of energy transition and beyond. And in order to stay abreast with their North American peers, they need stronger balance sheets than they have today.

MR. SARDANA: Okay. Thank you. And maybe that's a bit of a segue into my next question. You mentioned the McKinsey study, and you mentioned that, you know, they were having trouble with financing some of these projects. Was the financing trouble that they were having a function of the capital structure or the inherent project risk underlying these projects?

MR. COYNE: As I read the study, they pointed to investor uncertainty regarding future returns for these projects and on certain policies, so those coupled with technology uncertainty have made it a more challenging investment environment than McKinsey thought was necessary to meet these aggressive climate goals. So, it was three pronged. It was technology related, policy relied and just concerns amongst investors as to what those future returns would be.

MR. SARDANA: Okay. Thank you.

MS. ANDERSON: Yes, I do. So, there's one slide where

you talk -- I'm not sure who was it in saying that we might have growth in the order of the 10 to 20 percent because of the energy transition, so it gets me thinking about it from a shareholder's perspective. And a 10 to 20 percent growth, one would assume, is going to increase rate base, which is going to result in significantly increasing net income that would then lead to dividends to the shareholder even at the current ROE.

So, you know, looking at it from that perspective of the fair -- I mean, a fair return standard is the return on invested capital, yes, but from a shareholder's perspective, you know, even with the growth, aren't they looking potentially to get greater dividends even at the ROE as it is? And so increasing, you know, what's the impact now? You're the customer. The impact is you get to a 45 percent equity and a 10 percent ROE. Now there's even more net income potentially going to dividends to a shareholder.

So, like, we look at it from the fair return standard on invested capital, but what about from the shareholder's perspective? Aren't they, you know -- With this growth in transition, we talk about the risk, but what about the reward side of it, is increased rate base? So, how do I take that into account?

MR. COYNE: Sure. Yes, I think you pointed out the two prong aspects of increasing investment to meet challenges. The expectation is that, yes, the utilities will be investing additional quantities of both equity and

debt as long as the returns are compensatory to do so. And our point to the Board is that if the Board is providing returns that are competitive from a North American standpoint, then utilities will want to make those investments because they will be receiving a compensatory return, and that investors and debt likely will also feel as though these are good investments in Ontario, as they have felt in the past.

But in order to do so and to make those investments, our point to you is that there is some increase in that return that's required. Otherwise, Ontario's utilities are raising capital at a disadvantage, and that appears two different ways. One is if you're in equity markets and you go to your investors and you say, look, I can offer you a 9.21 percent return in Ontario or I can offer you a 10.75 percent return in Florida, they're going to say, thank you very much, I'll take the Florida return. I find that to be better.

And so, what we're looking to establish with these recommendations is an equilibrium for Ontario's utilities that will not put them at a disadvantage when it comes to raising that capital. But yes, if they do make those increases, increased investments in rate base, it will increase those earnings over time. That's correct.

MS. ANDERSON: Okay. Thank you. And my next question is around your views of no cap on the debt rate. That's one of your recommendations, not to set a cap on the debt rate. And did you take into account -- were you

considering that based on external debt or did you take into account that many, many utilities have promissory notes with their municipal shareholders, that kind of thing, and so it's a related-party transaction, as it were? So would your views change at all from that perspective?

MR. DANE: I believe the extension of the cap is recommended by other experts was to Enbridge and OPG. And so, our focus is really on whether that's applicable for them. And we provided evidence in an interrogatory that shows that, for instance, even at a similar credit rating, OPG's expected credit spreads are above others in the industry. So, the concern from our perspective is really that one cap won't necessarily apply to all utilities, particularly if it's set at a benchmark that's not reflective of the individual risks of the underlying companies. So, it's more from that perspective that we're focused.

MS. ANDERSON: So, you didn't really consider the perspective of a promissory note from a municipal related party? You didn't analyze that perspective?

MR. DANE: Not specifically. I think our point here is more generally applicable regardless of the source of the debt, is that the deployment of that debt is into companies of certain levels of risk. And even at -- whether it's from a municipal or from a public market, they still have to analyze the risks of the entity and would demand similar returns based on those risks.

MR. COYNE: And I must say that based on our North

American rate experience, and I would ask my colleagues if they have any different experience than I do in this, but I'm not aware of any regulator that caps debt as suggested here. The traditional approach, as you're aware of, is to examine the prudence of those costs. Were they raised under reasonable terms and things of that nature. But a cap is difficult to impose because, especially in Ontario, as you mentioned, commissioner, you have 70 plus utilities with different credit ratings and they raise capital and debt capital at different times and through different channels. So, to us it represents a very blunt instrument for something that requires more individual care as these entities come before you for rate cases.

MS. ANDERSON: Okay, thank you. Moving on to the three pronged test, so one of the tests is financial integrity. So, I'm not aware of any experience in Ontario where kind of the financial integrity of one of our regulated entities has been in question. So, is that -- so, what do you mean by financial integrity when you're thinking about the fair return standard?

MR. COYNE: We think of it, for a utility, it typically means maintenance of an investment-grade credit rating in Canada and able to access debt and/or equity capital under all market cycles. And, at a more fundamental level, about to meet its debt obligations on an ongoing basis. So, I think financial integrity is one of the minimum thresholds of the fair return standard.

MS. ANDERSON: Would you equate that to financial

viability, or is that, like -- in other words, viabilities you're about to go bankrupt or...

MR. COYNE: I would, yes.

MS. ANDERSON: Okay, thank you. Slide 7 just got me raised and I haven't researched these quotes, but both of the quotes sort of twigged in me that they talk about technologies and solar and the energy transition. And so, when you're looking at some of these, were these about the generation side of, you know, the sector? And were you distinguishing between vertically integrated utilities and the fact that here we mostly, other than OPG, mostly T&D? So, the scaled deployment of all these technologies made me think they were talking more along the lines of generation and energy transition, that kind of thing.

MR. COYNE: Maybe I could speak to the left-hand portion of the slide and ask Mr. Dane if he would speak to the right-hand side. In terms of the McKinsey study, you know, like McKinsey does, it was a fairly global view of the issue. So they were looking at the energy and regulated utility sector in fairly broad terms. And so, they were speaking primarily to the deployment of renewable energy resources. And I think of those probably as focused on the generation and production side.

But it is also the case, as we know, that in order to accommodate those resources, massive investments are required in the transmission infrastructure as well as the distribution infrastructure in order to be able to manage new types of generation resources, and also non-traditional

generation assets that are being deployed across the system.

But I think that the McKinsey study is more focused globally on how much renewable energy is going to be required to get to net zero by 2050 and the gap that they see existing there.

So, theirs wasn't a sector-specific focus. But I think if you read between the lines, it is focusing on the gap on the renewables side.

MS. ANDERSON: Thank you.

MR. COYNE: Let me ask Mr. Dane if he could address the Massachusetts decision was purely related to the T&D companies in the state.

MR. DANE: That's correct. The Massachusetts Department of Public Utilities here, in approving the electric sector modernization plans, those are for distribution companies, the three electric companies in Massachusetts. And those plans focus on the next five years, both in terms of the utilities' plans for increased reliability of the system, as well as about $2.5 billion in spending on the system. And, again, this is for distribution only.

And just a little bit of further context there. The DPU, or the department, as they're called, cost recovery is still being worked out in terms of the ESMPs, as they’re called, but they did allow, or they did approve a short-term reconciling recovery mechanism to start the utilities on their way in terms of these plans. So to your question,

it's for distribution only in that case.

MS. ANDERSON: Distribution, thank you. So my last question gets into my trying to get my head around the recommendation on WACC applying to DVAs and CWIP. So, let's talk the DVAs in particular.

Yes, I get that it's a deferred cost on the balance sheet. Actually, under IFRS, I guess it does flow through, a flow-through, the statements; I will have to get up on my accounting, there.

But the nature of them, does that not matter, the nature of what those DVAs were? Most of them, and I know there's some that are capital related, but most of them are an operating expense, or the difference between a revenue and an expense of, like, a variance account. And I know you said the recommendation is only for things that last more than a year; I think you said short term should be the status quo. But I am trying to get my head around applying a WACC to something that was an operating initially, if it had been recovered in that year.

So, can you help me understand why you would get a profit on something that was a deferred operating cost?

MR. DANE: Sure. I mean, to your question about the short-term, long-term nature, we answered some interrogatories on that as well, and we recognize that there may be some practicalities there. So, while we still would -- our recommendation would be the WACC to DVAs, we recognize that there could be a differentiation, for example, between group one and group two, group one being

more readily reconciled versus group two, et cetera.

But our focus is really on the commitment of capital by the utilities in those cases. And so, in the midst of a rate plan, they could be committing capital that they had to spend on those operating expenses. But then it gets hung up for a number of years, potentially, until it's dealt with in the next rate setting application.

So our focus is really on the fact that that capital is tied up for a longer period of time. And, as we say in our report, and I mentioned a few minutes ago, that's used with a -- that is done with a mix of debt and equity. And so tying those all together forms our recommendation about weighted average cost of capital return for those accounts.

MS. ANDERSON: Okay. And then just the other question was a clarification on, I think it was your slide 18, it mentions CWIP in rate base. And so, not AFUDC. Can you explain?

MR. DANE: In the quote?

MS. ANDERSON: Yes. It says rate base is defined as net plant, property, working capital and the construction, like CWIP, in rate base.

MR. DANE: Right. And I think that's specific to this quote where Bonbright is describing the concept between sources and uses of funds. And so I read this to be for those jurisdictions that allow CWIP in rate base --

MS. ANDERSON: Okay.

MR. DANE: -- whether you wouldn't earn a return, which is not the case here. So I think that's -- we didn't

want to put a partial quote in.

MS. ANDERSON: I got it.

MR. DANE: But I could see that would be confusing.

MS. ANDERSON: Yeah, okay, No, thank you. That's it, from me.

MR. JANIGAN: Thank you. Commissioner Mr. Sardana has one more question.

MR. SARDANA: Sorry, I should have asked this earlier. Clearly OPG is in a construction cycle and a refurbishing cycle right now; it is probably going to last a few more years. But once that cycle is over and they are operating these new refurbished reactors and perhaps the SMRs as well, would your view of their risk change at that point, when they turn from a construction -- you know, where there's a lot of risk in your view, and others, to more of an operational company now, for the next 30 or 40 years?

MR. DANE: Yes. No, it's a good question, and I think ultimately we would want to assess their risk at that time. And I think that's part of our recommendation about revisiting cost of capital every five years, rate setting plans being generally made for five years.

So certainly, if OPG is through its -- through this capital plan time period, that would affect their risk. But things change over time, so I wouldn't want to necessarily commit that it would change as an overall picture. But certainly we would want to take that into consideration.

MR. JANIGAN: Thank you, very much. Panel, I have no

questions for you. And we will take a break until 11:25. And we will at that point in time hear the Nexus presentation.

--- Recess taken at 11:08 a.m.

--- On resuming at 11:26 a.m.

MR. JANIGAN: Were all three presentations marked as exhibits?

MR. JOHNSON: Yes. I was going to say just before I -- in my haste to get out of the way, I forgot to mark my own presentation as an exhibit.

MR. RICHLER: So, we can mark the Concentric presentation as Exhibit KP1.2 and then while we're at it, we can mark the Nexus presentation as KP1.3, and Dr. Cleary's presentation as KP1.4.

EXHIBIT KP1.2: CONCENTRIC PRESENTATION.

EXHIBIT KP1.3: NEXUS PRESENTATION.

EXHIBIT KP1.4: DR. CLEARY'S PRESENTATION.

MR. JANIGAN: Okay. Ms. Stothart, could you introduce your Panel, please.

MS. STOTHART: Yes, absolutely. Pleasure to be here. Sarah Stothart on behalf of the Electricity Distributors Association. I'll also be joined by my colleague, Peter Ruby, later on in this proceeding, but he wasn't able to join today.

Turning to my panel, I have on the left Dr. Frank Pampush, and on the right, Ralph Zarumba. They are both from Nexus Economics, and with that, I'll turn it over to them for their presentation.

MR. RICHLER: Sorry, sir, just please make sure the green light is on your microphone and speak directly into the microphone, thanks.

NEXUS PRESENTATION

PRESENTATION BY MR. ZARUMBA

MR. ZARUMBA: Is this better? My apologies. We have been retained by the Electricity Distributors Association in this matter to address some of the issues in this proceeding, but not all. We are primarily focused on the ROE issues and some implications from the ROE issues and some of the variables that impact it.

Where are we today? We do not believe that the OEB is meeting the fair return standard with the current ROE based on the existing mechanism. We further respectfully disagree with London Economics that their proposal would meet the standard.

Two, we believe that the Board issued a very strong document with quite a few guidelines, we believe, that are appropriate and proper -- could we move to the next slide, please -- that should be recognized and retained in the future. After reviewing the filings of the other experts, we find that some consensus exist in areas. I think that should be recognized and it might streamline the process.

We would like to emphasize that we believe that Canada and the United States are a single capital market. In trying to differentiate between the two in terms of calculating the returns is incorrect and would simply introduce what we economists would call a disequilibrium.

Last, a word about the energy transition, which I believe Mr. Coyne, quoting from McKinsey report, talked about an inflection point. We believe this introduces a strategic risk into -- for the electricity distributors. Have we adjusted the ROE for the strategic risk? No. But we do want to point out that we believe that some of the other regulatory mechanisms which the OEB provides to the utilities needs to be reviewed to reflect is this change in the industry. I'll go into a little bit more detail on that later in the presentation.

Next slide. As I mentioned earlier, there are some areas of consensus in the approach to calculating ROEs, and then I've also compared it to some of the findings of the 2009 Board decision. For example, all parties, except for London Economics, agrees that the transaction cost should be included in the ROE calculation. That is consistent with the 2009 Board decision. All parties, except for London Economics, agree that multiple models should be used to calculate the ROE. Again, this is consistent with the 2009 Board decision. Last, with the exception of Dr. Cleary, all experts accept that U.S. utilities should be included in the list of comparable firms.

Next slide. We've already had a significant amount of discussion about the fair return standard, so I'm just going to briefly go over this slide and remind you that there's an opportunity cost, a comparable investment. And I'm going to go back to the point about there being a single capital market between Canada and the U.S. and

recognize that if Ontario does not provide a reasonable investment with all other variables being held equal, the utilities will be put at a disadvantage for attracting capital. There is the financial integrity standard. There's been some previous discussion and questions about is there problems with utilities attracting capital? Are they having problems? My comment to that question is: At the point where utility is having problems attracting capital, that is equivalent to not that a smoke alarm is going off; that is equivalent to the house is on fire. I have seen in my career utilities that were unable to attract capital, and it's only the rather extreme situations when that occurs.

Next slide, please. We have provided a graph that shows a benchmarking -- this is from our report -- of what we consider to be U.S. and Canadian utilities and what they have received in terms of authorized ROEs. We've re-levered this to 40 percent equity thickness so that everything is comparable. I have further identified firms that I believe are similar to Ontario in terms of adopting a more aggressive stance towards the energy transition. Those are the bold lines in the graph. The dots in the lines are the Canadian utilities, the Canadian peers. The blue line in the bottom is Ontario.

So, what could we determine from reviewing this graph? Ontario is significantly lower than many of the peers. The narrow blue lines are United States utilities that we did not identify as being peers in terms of behaviour; they're

just the rest of the group of companies. The thick lines are California, Massachusetts, New York, which we believe are similar to Ontario in many ways. They have multiyear rate plans, similar to Ontario. They have adopted aggressive energy transition policies, similar to Ontario.

The dots are Canadian utilities. The reason that they are dots and they're not lines is that we only have a single year of information for those companies. It's not that they're being treated any differently, but you notice, again, that our conclusion is that Ontario is below what we would consider to be peer benchmarks. That would indicate that Ontario may not be achieving the fair return standard. With that, the next several slides will be addressed by my colleague, Dr. Pampush.

PRESENTATION BY DR. PAMPUSH

DR. PAMPUSH: Yes. Good morning. It's an honour to be here. Thank you. I'll walk through several of these graphics that are quite similar in their look, their appearance, and they show different things, but let me start off with this one. I'll sort of give you a walk through of it.

I have the Nexus Economics result, my 11.08 percent, and I also have others, Dr. Cleary, what I call LEI has filed their 8.95 percent, Concentric, 10.0. And then it's really, I call it, LEI consistent with 2009 Board order. Understand that this is me, Nexus, Frank Pampush, who has looked at the LEI report and said, well, if you do this and this, here is what the result would be. So it's me, you

know?

But for summary purposes, I'm pulling it from the LEI report and that is what I would refer to it. And I'll go into detail on that in a moment.

I also want to just walk you through this in the sense of those red vertical lines. What are they showing us? What I did with all of my calculations is I computed confidence intervals on them, 95 percent confidence. And those things are based on something that I think all of us are a little bit more familiar with, and that's the term margin of error.

In a political season, we have heard plenty of examples: Candidate A is pulling at 50, candidate B is at 49, but that's all within our margin of error of plus or minus 3 percent. It's not an error. That's just what they call it. It's not really a mistake. They just understand that, when they are polling, they are not asking every single person in the whole world what they think. They are asking a sample, and all samples have margins of error.

My confidence limits, based on the 95 percent level of confidence is the mean, 11.08, minus the margin of error, and that comes to 10.39. That's the left-most vertical bar. And the right-most vertical bar, 11.81, is the mean plus my margin of error. And I computed those based on the variability of my own data.

For example, when I had the capital asset pricing model and I have a group of comparable, risk-comparable firms, their betas are different. So I can see the noise

in that data and, from that, I can compute margins of error. And that's what I do.

So the purpose of that is saying let's take, for example, what I call the LEI consistent with 2009 Board order at 10.4 percent. If it's within the margin of error, just like those politicians polling at 50 and 49, I cannot say it's different than my result. We have microscopes, and we are trying look in, and we can't focus them any stronger than what they are.

So, at 10.4, it might be in there. Concentric, this is very interesting. Their computations, Concentric's computations, are based on equity thickness of 45 percent. I didn't address equity thickness. I accepted it as parametric, and so I used the existing 40. If I were to use 45 instead of 40, my 11.08 goes down, my confidence limits shift left.

Alternatively, if I were to say, okay, Mr. Concentric, we're going to re-lever you to 60-40 instead of to the 45, theirs would bump up. Would it be inside that limit? I don't know, I haven't done it. But I just wanted to give you a sort of a sense of what's going on.

And, of course, Dr. Cleary's results are just outliers, just far different.

May I have the next slide, please? So, here, this is my computations of LEI. And I want to make sure that my friends at LEI understand that I am not trying to put words in their mouths or anything like that. I have the LEI as filed, 8.95.

Then I said, to make this in my view consistent with the 2009 Board order, I am going to make just two adjustments: I am going to add back in transactions costs, and I am going to evaluate multiple models, both of which have firm justification, firm reasoning.

First, I just add in the transactions cost. That's the 50 basis Points, 8.95 to 9.45. Now I am going to pull those back out, and I am going to go to multiple models. LEI had their capital asset pricing model. They had a DCF for electrics; it was either 10.53 or 10.35. But they had DCF result, and they had their annual adjustment mechanism econometric equation. And I looked at that and I said, oh, they're using an econometric equation to forecast authorized returns -- using the S&P database on U.S. electric utilities, they are forecasting authorized returns based on interest rates.

Well, I have some interest rates right now, right here, that I could populate that model with and see what it implies. And my view was if this is good enough for the annual adjustment mechanism, why not also see what it implies for the base ROE?

So I populated it, and that was my third result that I am averaging in to get the LEI multiple model's, 9.9. Then I add in the transactions cost, get to the 10.4; it is within my margin of error, that left-most one, at 10.36.

And then I just adjusted the risk premium model for leverage, because U.S. electric utilities tend to average 50-50. So, once again, I just said, well, if this is going

to apply to Ontario, and if Ontario were to maintain the 60-40 debt equity split, it would imply the 10.59.

So, those were basically -- the purple line is the 10.4 that you saw in the prior graph.

May I have the next, please. The three models, these are very popularly used, as I have seen in a variety of jurisdictions, the capital asset pricing model. You know, by the way, I had to dig it up from my first year of graduate school textbook in econometrics, Henri Theil, 1971; so we are going back aways: "Models are to be used but not believed." He understands as an econometrician that we have to use models, but that each model has its weak point. That's the reason.

And you can read it at page 21 of the 2009 Board report. It discusses why multiple models are useful. Each model has its own idiosyncrasies, places where in the particular capital market it works better than the other. The unfortunate thing is one of the most important numbers in all of economics and finance is the cost of equity, and we can't see it. We have to infer it from these imperfect models.

Another quote: this is from Eugene Fama, a Nobel Prize winner in economics, who was talking specifically about the cap model. He was pointing out one issue after the other in the application of the cap model. But he said all interesting models involve unrealistic simplifications. It's a complex world we live in, and we just can't handle -- we need to think through clearly based on foundational

principles what we are looking at, and then we can add complexity to it. So each one of these models is going to have its issues.

Cap model says the only thing that matters is what the marginal investor thinks of the mean and variance of expected returns. That's it. And then it evaluates. It's a single line. It takes all of the capital market uncertainty and places it on a single line and says, you know, if it's just an average investment, it's going to get the average return, the average equity return, which is the market risk premium plus the risk-free rate.

If there's a little bit less risk, and that little bit less risk is measured by the beta that we are all familiar with, then you move up or down that line. But you never leave the line.

You know, all of these models depend on discounted cash flow model. That is based on the fundamental theory of value. It says all economic assets, the value of those assets is equal to the expected future cash flow that those assets will generate, discounted at the relevant risk-adjusted rate of return. That's the fundamental theory of value.

We, as practitioners, sneak in and we pull out the value and we put in the price. We assume markets are efficient. We assume that investors are rational. We assume that price at all points in time is equal to value. And if those things are true, then the DCF model works.

Risk premium model, that's really sort of an ad hoc

thing. Concentric, Nexus did pretty much the same thing. LEI, with their annual adjustment mechanism, that impounded and put to work as a base ROE calculation. I liked what they did. I thought, oh, this is interesting. I'm going to do what they did. But they regressed authorized returns on risk-free rate and Moody's BWA to get that variability. The only twist is I did with it is I put everybody on the same leverage and then made my calculations. So, you had three approaches even in this one.

May I go to the next slide, please. CAPM results, again, you have multiple parties, multiple methods, well, a single method here, really, multiple parties, multiple data sets, a lot of congruence in the results. What I did here with the LEI as filed as the 8.95, here I was looking at this more as a practitioner, as a forecaster, a prediction analyst. The market risk premium was based on U.S. data. The betas were based on U.S. data. I said, well, don't swap in a Canadian risk-free rate. Use the U.S. risk-free rate in that instance, and that's where I got the 9.80 from. The rest, Concentric using historical MRP, I could not tell the difference statistically between my result and theirs.

May I have the next slide, please. This is my discounted cash flow and, again, you can see that there is some harmony there. Again, way different people. Now, so way different people, way different modelling experiences and different data sets. The only one that's a significant outlier is Dr. Cleary. I haven't done a total deep dive on

why that would be the case, but it's just statistically significantly different than the rest, let's just say.

The next, please. And finally, the risk premium, there's some similarity. The Concentric U.S. electric, LEI, I did one thing. I computed -- well, I did two things. One is that figure 69, I computed what it implied for authorized returns based on their regression equation. And then, because those U.S. utilities are by and large 50-50, I levered it to the 60-40 debt equity, and that's my LEI adjusted for leverage. Once again, my numbers and I just, you know, wanted to keep it short and sweet as far as labelling this graphic. And that was the 10.80. Again, Dr. Cleary was substantially different than the rest.

May I have the next slide, please.

MR. ZARUMBA: This graph addresses our claim that the Canadian and U.S. financial markets are going together, essentially a single market. And what this graph shows is information on the Canadian 10-year bond and 10-year U.S. treasuries from 1962 to the present.

Now, you'll notice that in 1993 there's a green vertical line. That marks when the North American Free Trade Agreement was enacted. So, we look at the period pre-NAFTA, the difference between Canadian and U.S. 10-year bonds is about 102 basis points, 1 percent. However, if we look at the period post-NAFTA, the difference averages to be 1.3 basis points, 1/100s of a percent. So, that would suggest that there really should be no, in the long run, there should be no difference in the risk-free rate between

the two countries, that the two have aligned. They could have short-term differences, short-term differences triggered by all sorts of events that I would characterize as noise, but this essentially supports, you know, the harmonization of the two economies.

There is a graph in the appendix, which is just additional information. That also shows the balance of trade between Canada and the U.S., where Canada is -- the U.S. is Canada's primary trading partner, over 70 percent of the trade. If we did it other way around, it's not as dramatic, but Canada, I believe, is the third largest trading partner to the U.S. So, we're very highly linked and to think that there is a significant difference, I think, is an incorrect assumption.

The next slide addresses choices of peers, and in this slide we will respectfully disagree with Dr. Cleary, who chose Canadian utilities as peers, five Canadian utilities. I looked at three of those Canadian utilities. In fact, I think I worked for all three of these firms at one point in my career. And I took a look at how much of their revenues is derived from Canada, the U.S., or outside of Canada and the U.S.

Emera, Fortis and Algonquin received the majority of their revenues, over 50 percent, from U.S. investments, which begs the question: What is a Canadian utility? We essentially are, you know, a single market, and they're investing cross border. Algonquin, at 3 percent, I believe that's entirely attributable to one small natural gas

distribution company in New Brunswick. The rest of Algonquin is a utility in Bermuda. So, you know, what is a Canadian company? What is a U.S. company? It's, you know, we have to look at a group of peers that captures companies from both countries.

My last slide in the presentation addresses strategic risk, which I consider to be a very important issue for the OEB not only in this proceeding, but just in all other matters, and I would like to note that it's my understanding that the OEB has opened up a proceeding looking at the incremental capital mechanism, which I think is, you know, an excellent move forward, although I would also suggest you look at the other regulatory mechanisms, like the IRM. And the reason I make that recommendation is I looked at capital investment between -- I think somebody might have a mic on and may not intend to. Look at capital investments historically and what we believe will occur in the future. You look at the historical time period.

THE STENOGRAPHER: Sorry, but the presenter is muted. I can't hear anybody now.

MR. JANIGAN: Sorry about that. Would you continue, Mr. Zarumba?

MR. ZARUMBA: My pleasure, and no apologies are necessary. I am going to start over with slide 13.

Slide 13 illustrates investment trajectories, historically. And what we are projecting based on some analysis performed by the Electricity Distributors Association which was, with the foundations found in the

IESO forecast. So these are official Ontario numbers.

I am going to point out two interesting findings. Historical investment has pretty much tracked the number of customers, and that is not surprising. And I am quoting a 2014 Navigant Consulting report for work done on behalf of the OEB that basically stated that customers -- at this time, it was residential customers -- either had flat usage per customer or declining use per customer. And that was across pretty much all of the distributors at that time. I think there were maybe three or four outliers that actually had some growth.

However, we move into the future -- different scenarios. You have some very significant growth, per customer growth, which implies growth per customer.

So what is going on here? This basically is reflecting the changes in customer behaviour, changes in market. What does this imply? In my opinion, it implies greater risk. As I stated before, we did not adjust our ROE analysis to take into account strategic risk. However, I think that this does suggest that some of the mechanisms that the OEB employs may need to be updated because, for example, the total factor productivity analysis is based on number of customers. But implied in that analysis is that the kilowatts per customer are staying relatively stable. And that is probably not true in the future.

Is this analysis just simply speculation on the part of the Nexus project team? I will point you to slides 40 and 41, which is some information from a filing from

National Grid Massachusetts that showed their summer kilowatt per work order, what has happened historically for the last several years. It has increased significantly, and this is just more of the energy transition from a jurisdiction that, in my opinion, is very similar to Ontario.

So I am going to conclude that in lieu of any type of an ad hoc adjustment to the ROE, that the IRM and the other regulatory mechanisms should probably be revisited. They were periodically revisited in the past. I believe it's been well over 10 years, so it's due.

That concludes our formal presentation.

MR. JANIGAN: Thank you, very much. Are there any questions? Commissioner Sardana?

QUESTIONS BY THE BOARD

MS. ANDERSON: Thank you, Mr. Janigan. Just maybe one exploratory question on this very slide, on the load growth: Did you get a chance to take a look at load growth versus GDP over the same time period, and even a forecast of GDP? Did the EDA or the IESO provide that?

MR. ZARUMBA: No. And I think, since we are in a transition, I don't believe that metric would be a strong metric. If you have a stable state where the industry is not changing, that maybe would not be a bad approach because GDP would be correlated with customers. And if load per customer was staying relatively flat, okay.

This is a change in the industry, and I would like to point out that I think I have seen two other changes like

this in my career, which is now getting kind of long. In the 1990s, with the introduction of wholesale market changes and retail open access, and the introduction of nuclear power generation, which I captured at the beginning of my career in that 1980s, when we were trying to figure out how to pay for those plants, because there were the issues about overbuilding, and the fact that these plants came in at higher costs than anticipated.

So I think that's maybe a little long-winded answer to your question, why we looked at it in the way we did, and the fact that we have to recognize that the industry is changing.

MR. SARDANA: Okay. And then perhaps this is a follow-up. There seems to be a presumption, then, that all utilities are at capacity right now and that, you know, the next kilowatt is going to require oodles of capex. Are most utilities at capacity in their infrastructure?

MR. ZARUMBA: I did not do that analysis but if, you know, in terms of a -- I am working for the Electricity Distributors Association. Electric distribution systems, you know, grow incrementally to serve customers and increase load -- both, as you well know as formerly being from a distributor.

MR. SARDANA: Mm-hmm. Thank you.

MR. JANIGAN: Ms. Anderson?

MS. ANDERSON: So, confidence levels. I understand the concept. I probably need to do some more reading of your work. Can you reference a particular place where I

could understand more of how you came up with those numbers? Because, I mean, I understand you mentioned things like variations in beta, which would be related more to CAPM and I looked at your slide 6, which has confidence levels on sort of the overall ROE, then looked at the confidence levels sort of very similar to the confidence levels on slide 10, which was the risk premium methodology, but they're very different levels for the discounted cash flow.

Like, did you do them individually and then average them somehow or -- I'm trying to understand the sort of the mechanism to come up with those confidence levels?

DR. PAMPUSH: Right. I did do them individually. So on the cap model, for instance, the primary variability in my analysis was the different betas across the different firms. I would have loved, but I did not do, the variability in the market risk premium. So, that would probably have, for the cap model -- and sort of I'll hop over to your second question on that. So, on the cap model, I had my confidence limits for the cap model.

Then when I ran over to the DCF model, I had differences in growth rates, and that was the primary driver of variability there. And I put the -- on that graph, that would be just -- those vertical lines, those confidence limits there, were based on just the DCF.

So, you're right. For the overall -- and I'll tell you how I get to the overall in a second. But for the overall, I had that. And then for each individual, I had

something different.

Now, what I did to get the overall is something that they use in what are called meta studies. The Centers for Disease Control, they have to look at all these different studies that might be going with a drug or something. Some of them have just a few patients, some of them have lots of patients, some of them have little -- so they have methods. Their primary method for saying, well, this is how I'm going to aggregate these studies and see what they're telling me is to use what's called the inverse variance approach.

So, when I computed these confidence intervals, upstream from that I had computed the variability in that data. And then, so I took, like, one over the variance or -- it wasn't actually one over the variance it was one over the standard error, but point being one over the variance for my cap model, one over the variance for my DCF, one over the variance of the risk premium, and then I aggregated those together. So, you know how oftentimes you'll see, well I did it 0.3, 0.3, 0.3, you know, one-third, one-third, one-third for each of them? I did it by I'm going to put the most weight on the procedure, you know, the method that had the least variability. And in mine, if the least variability was on the cap model, I think that got in the 40s. The DCF was next, also maybe in the lower 40s percent I'm talking. And then the risk premium had a lot more scatter associated with it. And if I recall, it got 12 or 14 percent weight. And that's how I

came up with my overall average and also how I came up with my overall confidence limits that are different. They're a weighted average, if you will, of those other three -- of the three primary methods.

MS. ANDERSON: Okay. So, if I would summarize it, you put more weight on those with less variability, is probably the key takeaway, when you were, you know, coming up with the overall confidence for the ROE on slide 6?

DR. PAMPUSH: Correct.

MS. ANDERSON: Okay. Thank you. So, with slide 12, you talk about the fact that Canadian utilities operate -- if I can find my slide 12 now. Yes. Canadian electricities compete with U.S. utilities for capital and three of the five are largely U.S. utilities in their operations. So, the point you're making is for the peer group, you think you should use both Canadian and U.S.? I think that's the point to take?

MR. ZARUMBA: That is correct.

MS. ANDERSON: What do I take from the fact that that, you know, is that true of the Ontario market? Is where my kind of questions come. I don't know. I mean, there are some that obviously operate outside of Ontario, but out of my 70 regulated utilities, they don't. Most don't. So, does that change my thinking of whether you're using both U.S. and Canada for the peer groups?

MR. ZARUMBA: Well, this has to do with the peers and what your statement is saying is, well maybe I need a special peer group just for Ontario, but is Ontario really

different than everybody else? I think, you know, they are electric utilities of one variety or another, and therefore the peer group should be the broader group.

I mean, I used these three to show that when you narrow it down to just Canadian utilities, you could argue these three utilities, these three companies, should not be included in the analysis because they're more U.S. than they are Canadian. And there was an argument made that U.S. utilities have higher betas. Well, these companies then probably shouldn't be included. And then I'll point out that if we stay with it, okay, we're now we're down to a peer group of two Canadian utilities and one of them is already in Ontario, so you can make the argument they should not be included in the analysis because of their circularity. Well, now you're down to a peer group of one, which I think everybody agrees is probably inappropriate.

MS. ANDERSON: Okay. I think it was slide 13 you talk about -- maybe it was just prompted me on slide -- you talked about the risk, the fact that we've got this growth risk and related to energy transition, you're calling it strategic risk. But with growth, is it all risk or is there some reward as well?

MR. ZARUMBA: Well, let me point out one thing. These projections are based on what somebody, you know, some very smart people think the world will look like in the next 25 years, but it's not based on any sort of historical patterns, which to me it adds uncertainty, which is not risk. It's something much more difficult to manage.

In terms of rewards, there was comments earlier today about, well, these utilities are growing, they should be happy. Yes, but the issue is, you know, what if the growth doesn't come when it's supposed to? What if the growth never comes?

In our report, I reference some work from the U.S. energy information administration that dates back to nuclear power adoption, you know, many decades ago in the United States. And a lot of that was developed based on assumptions about load growth and they had load forecasts that occurred in the 1960s which had incredible amount of growth, then load growth forecasts in the 1970s, not quite as much growth. And then let's go to the 1980s. Oops, almost no growth. And that is, you know, the type -- we don't have very good information right now about the future because we are trying to figure out what the new world is going to look like, which is why, you know, everybody in this room is facing that challenge. And it's going to be very exciting times, but it's not -- there is no easy answer. To say is that going to reward utilities?

In the past there have been something called disallowances because assets were not used and useful. And I think that there are those possibilities in the future. And that's why I think we need to take a broader look. You know, ROE is one thing, but outside of cost of capital issues, at regulatory mechanisms in general and how they are managed. You know, take a look at some other jurisdictions have abandoned TFP. They're looking at, you

know, other mechanisms to address capex. As a possibility, I'm not advocating a solution, I'm just saying I think it's time for everybody to start thinking.

MS. ANDERSON: Okay. So, I'm clear, you haven't incorporated strategic risk. Your view of strategic risk is the energy transition in general, so you haven't incorporated that sort of future of energy transition into your numbers. Is that correct?

MR. ZARUMBA: That is correct.

MS. ANDERSON: And I saw that it looked like others were incorporating that as part of business risk?

MR. ZARUMBA: And I respectfully disagree with the other experts. I think business risk is associated with day-to-day operations of an organization that is relatively stable. And, you know, very small incremental changes, which would be the period that was captured in the Navigant study in 2014.

What's happening? Customers are using about as much as they used to, maybe a little less, but everything is a function of customers. And I am arguing we are at -- as the McKinsey that Mr. Coyne quoted, we are at an inflection point.

And what makes things uncertain is we are not quite sure how people are going to behave. It is all based on prognostication of things that we don't have experience with.

MS. ANDERSON: Okay. Thank you.

MR. ZARUMBA: Thank you for your good questions.

MR. JANIGAN: Thank you. I just have one question. I am confused as to the impact of potential energy transition on essentially the recommendations here. My understanding was that because of the likelihood of energy transition, that it was imperative that the ROE match the ability to attract capital for that energy transition, even though it's not happening now. Would that sort of be a summary?

MR. ZARUMBA: I think the ROE should be based on the analyses that have been put on the record in this proceeding. I obviously think that the recommendations that we prepared are appropriate, and there's some debate; that's fine.

I think we need to recognize that the energy transition will occur. We have not incorporated that into our analysis, but we wanted to alert this issue to the Board because we believe that it could impact the other regulatory mechanisms which you have authority over, the IFM, the -- you know, basically all of the mechanisms.

A big question in my mind would be should you retain a total factor productivity approach, or, like many in what I consider to be similar jurisdictions, move to a partial factor productivity approach and handle capital in some other way that helps manage the risk.

MR. JANIGAN: Okay. Thank you, very much for that. Those are all my questions. And I believe we will take a lunch break now and come back at 1:20.

--- Luncheon recess taken at 12:19 p.m.

--- On resuming at 1:21 p.m.

MR. MONDROW: Just before I do, and I've spoken with a couple of my colleagues, there was mention a few times this morning of the McKinsey study and the Massachusetts decision and I think they were even reflected in some of the slides, and I was going to suggest if it's all right with the Board that those documents be filed in due course. And I don't believe that the OEA, Mr. Smith, nor Mr. O'Leary have any objection.

MR. SMITH: No, perfectly fine.

MR. MONDROW: Thank you, sir. And so, with that, I'll introduce you to Dr. Sean Cleary who is in the witness box, as it were. I know him as -- and I know we're not doing qualifications, I know him as a Ph.D. finance in Smith School of Business, but apparently he's also an outlier and substantially different. So, with that very brief introduction on behalf of AMPCO for the purpose of this this evidence and supported by the customer groups, we're happy to have a different opinion before you. Dr. Cleary.

AMPCO PRESENTATION

PRESENTATION BY DR. CLEARY

DR. CLEARY: Thank you having me here today. I'm happy to speak about my evidence and how it compares with those of the other experts involved in the proceeding.

So, if you could go to the next slide, I'll just give you a quick overview of what I'm going to discuss. ROE matters, at a high level, some notes on allowed ROEs, and then the base ROE estimates, which I think most of the experts have talked about and I will as well. And also the

LCBF and utility spread factors, how to estimate them, the adjustment factors, and then a little bit in conclusion on allowed equity ratios.

So, if we could go to the next slide. And I think most people involved in these proceedings would agree that, and certainly every proceeding I've been involved in, that the market as a whole, regulated operating utilities are less risky than the market as a whole. So, I think it's interesting with all the references to me being the outlier and whatnot that none of the other experts make any reference to their expected market return and how their recommendations stack up with real market data. I provide some evidence showing, you know, experts managing tens of trillions of dollars, over 25 of them predict about 6.1 percent over the next 5 to 10 years. Historical evidence suggests about 8.5 percent if you take the real returns and add about 2 percent expected inflation, and I come in somewhere in the middle there about 7.5 percent.

So, if you turn to the next slide, you can see that if we consider that 7.5 percent of mine as the upper bound for what the required return on equity is for regulated operating utilities, my estimate comes in slightly below that, which is what you would expect if they're less risky than market, whereas the estimates of LEI, Concentric and Nexus are considerably higher than that. So, that, to me, suggests that they believe that regulated operating utilities in Ontario should be earning more than what market participants expect on the market going forward over

the next 5 to 10 years.

So, if we go to the next slide, please, I'm going to talk a little bit about Concentric's and Nexus' recommendations in particular, and I guess the reason their estimates come in so high is they seem to be gravitating to the allowed ROEs particularly in the U.S. that are much higher than in Canada as I think we're all aware of by now, and, you know, somewhere in the nine-and-a half to 10 percent range. And there's heavy emphasis on that in their models with the various inputs and assumptions they make, which I'll discuss later, and upcoming into support them that they always kind of should be around what the U.S. allowed.

And in particular, if you look at Concentric's ER recommendations of 45 percent, it recommends that's to bring it in line with U.S. utilities when their own evidence even shows it's right in line with the Canadian utilities.

So, if we could actually just go to the next slide and I'll pick up on just a couple other points. Back to that 10 percent recommendation of 45 percent equity ratio recommendation by Concentric, that's higher than what they recommended for Newfoundland Power, you know, just 10 months ago. And even in those proceedings they noted several risks that Newfoundland Power faced due to its small size, due to its weak macro and demographic conditions and potential issues with future demand and slow potential growth, which is in contrast to they're arguing

it's a big risk to the Ontario utilities that they have this opportunity to grow fast.

I have also noted, inconsistent I would say with their Alberta recommendations, again, just about 15, 16 months ago of nine-and-a-half percent, which is lower than 10 percent they're recommending for Ontario utilities, and 40 percent equity ratio. But at the time, the recommendation was to bring the deemed equity ratios in line with the comparable risk in Ontario.

So, if they thought Alberta utilities were a comparable risk to Ontario utilities 15 months ago, then why are they now suggesting that Ontario -- implicitly suggesting, I should say -- are riskier because they have a higher ROE and 5 percent extra equity thickness?

Okay. So, now a little bit, if you can move to the next slide, please, thank you. A couple of comments on allowed ROEs and I'll get into the estimates themselves. If you look at this chart which is in my evidence, the top line in the blue line, that's the allowed ROE since 2004 in Ontario, and of course since 2010s would be when the formula was adopted. And what you can see there is it's fairly steady. It started at 10 in 2004 and it went all the way -- sorry, then it's down to 9.21 percent, so it has come down somewhat. But if you look at the bottom lines there, the RF would be the 30-year government yield, the purple line on the bottom. And the green line, which is the A-rated utility yield, which has a direct bearing on the cost of equity to utilities because the cost of equity

will always be your cost of debt plus a risk premium. We will argue over what that risk premium should be, but definitely that's basic Finance 101. Right? Because the same entity, their debt is less risky than their equity.

And if you look at that chart, you can see that there was a significant decline along that chart on the bottom but not a corresponding decline in terms of allowing ROEs. And as a result, the A-rated utility spread has changed from 3.8 percent in 2004 and 4.6 percent spread over the allowed -- over risk-free rate to what it sat at when I prepared this analysis, 4.5 percent for the A-rated spread, so that increased 80 basis points, and 5.9 percent for the spread over government utilities, so that increased 140 basis points, which is a significant increase.

Next slide, please, and I'll just kind of follow up a little bit on this. These are just kind of noting those stats that I noted. If you look at the bottom line there, it tells you the average ROE spread over that period was 6 percent over the risk-free rate. Now, if you put that into a CAPM model, which we're all getting kind of used to listening to, that corresponds to a market risk premium of 12 percent if we use a beta of 0.5 for the utilities. Or if we use a beta of 1, it's a risk premium -- market risk premium 6 percent, which is also at the high end of market risk premiums. So, it's just created a situation where, according to CAPM, the allowed ROEs have been too high. And I think the point has been made here and all of the experts do use the CAPM, so I think it's an important point

to recognize. Nobody is disputing the reliability of it or the fact that it's a legitimate model. Let's put it that way. You also see the average ROE spread was 4.6 percent. Now, in the bond yield plus risk premium that I use that's used widely by CFOs and financial analysts, it's in the CFA curriculum, that is at the upper end of that typical spread of 2 to 5 percent that you usually use with 3 being for an average risk utility, so that also indicates excess compensation.

Next slide, please. And finally, you know, this point, that means that if you're basing, as the OEB formula does, you're basing the cost of equity on two important factors that affect its cost of equity, government rates and the rates they can borrow at, A-rated utility yields, and those are both declined but the allowed ROE hasn't, then something is going wrong here. And it's not unique to Ontario. It's across Canada. It's even more prevalent in the U.S., and I cite a couple of studies there that note that. Okay?

If we just go to these hearings, and we refer to allowed ROEs in other jurisdictions, then it becomes a circular argument because if they haven't had a hearing and we are having one, they haven't lowered their ROE first. So, I recognize it's difficult to be the first to start to lower it, but the bottom line is that kind of resistance, you know -- what do you call it, inertia, if you will -- has led to the fact that they just gradually, through time, these costs -- these inputs into the cost of equity have

declined, but the allowed ROEs have not declined in step.

So, one last point on this. And if you could turn to the next slide, please. Where are we seeing evidence that this is the case? And one of the things -- I look at the price-to-book ratio analysis in my analysis. I don't include the cost of equity estimates in my final estimate, but I look at it as a way to think, what does the market think is going on here?

And the fact that the -- you know, if the allowed ROE is exactly equal to their cost of equity, then the price-to-book ratio should be 1.0. Okay? It means it's allowing -- it's earning enough profit and it's earning zero economic profit, which means it's earning enough in accounting profit to account for its reinvestments and so on and so forth.

With it sitting at 1.45 for Canadian utilities and having averaged 1.65 over the recent seven-year period, that suggests there's some economic excess economic rent going on there.

And if you look at Hydro One, which is, as pointed out earlier, the mostly pure-play regulated operating utility, it was 2.04. And they are subject to the OEB formula and the allowed ROEs here. So it doesn't seem to suggest that the market thinks that they are earning too low an allowed ROE.

In the U.S., of course, we see a little bit higher, which is consistent with the allowed ROEs we see there, and the higher allowed equity ratio. Okay.

To the next slide, please? So the other thing and, again, this is a topic that has come up this morning. The heavy reliance on U.S. comparators by all three of the other groups of experts, LEI, 83 percent by my count, Concentric, 76 percent in its North American proxy group, which relies most commonly --

Sorry, I just saw on the screen, it's Dr. "Clearly" up there, instead of Dr. Cleary. Sorry, this is a family joke because so many of the IRs, I see "Dr. Clearly says this." Anyway, my apologies.

Nexus, 88 percent. So, you can see they are heavily weighted, you know, over four-fifths of their sample is based on U.S. utilities. But Appendix B of my evidence shows they have higher business risk. Appendix C shows they have almost double betas. So by putting those betas, 80 percent of them are U.S. betas. That means they are going to get, by definition, higher beta estimates than me.

Moving to the next slide, please. So, where does this put us in terms of -- let's go through the three different types of models. First of all, the CAPM that we have already talked about. So, you can see the model. Really, there's only three inputs in there. You need a risk-free rate, a beta and a market risk premium. Okay?

The market risk premium I think it kind of gets lost in Here, that it's actually supposed to measure the expected return on the market minus the risk-free rate. Okay? Sometimes, it is just more convenient to look at the MRP.

Okay. So if we look at the Rf estimates, we can see that, not too much difference until you get to Nexus, because Nexus uses the U.S. risk-free rate as opposed to the Canadian risk-free rate.

Concentric and LEI base it on forecasts, which I am going to talk about in a second. But today, the forecasts are pretty much flat, so it's not much difference. In some proceedings it can make a significant difference, so I stand by my guns on that, in terms of usual actually GOC. And I actually put in that the actual was 3.19 as of August 29 and, as of yesterday, it was 3.17, so after the Bank of Canada announcement. So it's still right in there.

Next slide, please. Now I use the actual, because I believe it's the most -- you know, that was as of June. If you are going to do it for the next test period, I would say you use as close to the end of 2024 as is feasible for you, administratively -- September 30 or even October 31, if it's possible.

LEI uses 3.19 percent, the average of the 30-year forecast. Concentric uses the 10-year forecast from Consensus Economics. And then for some reason adds the historical spread of 0.33 percent, even though that spread is around zero today, and was negative at the time of their evidence. That is one of the problems of using those 10-year forecasts and adding a spread to it. This spread varies through time.

Nexus for some reason uses 4.06 percent, which is the average of 30-year U.S. yield forecasts.

The problem with using those forecasts is, in CAPM -- this is not really considered by the other experts -- the model itself as it's derived, it's supposed to be the risk-free rates you can earn today. The fact you think they are going to be 3.45 a year from now doesn't mean you can buy a risk-free investment today and earn 3.45 percent. Okay? The U.S. one I would argue is not the appropriate one, and also entails foreign exchange risk.

So the other thing, with this notion of using forecasts instead of using the actual, well, if you look at Appendix A of my evidence, I show that there's a 40 -- over a significant period of time, I can't remember it offhand, there's a 40 percent upward bias estimate. Those forecasts tend to always say that rates are going up. Not always, but over -- more consistently than going down. And it's actually identical to the number that Concentric found in their evidence when they were looking at the borrowing rates for utilities. So, it was complete consistent with a 40-basis point upward bias.

So my question is why do we go through all this trouble to use forecasts? And I would cite some other studies; it is not just my evidence, but there are all kinds of studies in the academics where they look at U.S. bond rate or U.S. risk-free rates, showing that this bias exists, and you are betting off to use the actual.

That is by the way why the Bank of Canada just doesn't forecast the future dollar of the Canadian dollar, because they used to forecast. And they said, using the existing

always works out better. Now I know it's apples and oranges, but it's the same kind of logic.

Also, it's a lot more work and, I think in the long run, it doesn't work as well.

So if we go to the next slide, please. Let's talk about the MRP Estimates, because there are three estimates in CAPM. And the second is -- well, the second or third, however you organize it -- is the MRP. And what you see on the left there is I put in the MRPs, the historical MRPs from the Dimson et al. study, which is 116 years of evidence that shows, in Canada, the arithmetic average was 4.2 percent. The geometric average is actually much lower, 3.1. And, in the U.S., it is 5.8 percent. Okay?

You look at the Fernandez 2024 study, and I think someone referenced some of his work earlier today, but he updates these forecasts for future. Like, what are you using in your CAPM models for MRPs. And he surveys professionals, he surveys academics, and puts them all together, and usually has a large sample size.

And, for Canada, for 2024, at 5.2 percent; for the U.S., it's 5.5 percent. And those are typically between 4 and 6 percent somewhere, which is what I know from practice that analysts always use when they use their CAPM. But, you know, maybe three in seven in extreme circumstances, but almost always between four and six.

If you actually did it the other way and looked at my forecasts for the expected return on the market of 6.1 percent for Canada and 6.8 percent for the U.S., and

subtracted the existing risk-free rate from that, you would get an even lower number of 3.0 to 2.74 percent.

You can see that I am right in line with that, at 5 percent. And that's, you know, the typical analyst, what they do. And you talk about, you know, accessing capital and that. Well, guess what? It's the people who are managing the trillions of dollars who are the ones who are going to estimate what they are willing to pay for your stock, which in turn estimates your cost of equity. Right? It's not what we argue in this room; it's what they do when they are doing their analysis.

So, I took the 5 percent, recognizing it's kind of like a medium-risk situation now, an average risk, if you will. Yes, we have some subsiding risks of inflation offsetting with some minor risks of maybe not quite a soft landing. But it's not like if I look at the numbers, the price earnings, ratios, the dividend yields, the yield spreads, they're all pretty typical with what you would expect for capital market conditions today, and I think the A-rated yield spread was exactly at the average when I prepared my evidence, which kind of tells you it's still pretty -- and I think it's still pretty close.

In contrast, you see these talking about outliers of, you know, 8.3 percent, 8.8 percent, which, you know, if you combine 8.8 percent with the -- and they use U.S. risk-free rate, so I think it was four-and-a-half percent or something they had, so that's like an expected return on the market of 13 percent, which just doesn't fly. It's

just not what the finance professionals would consider a reasonable estimate. And Concentric is somewhere in the middle. I think I put both of theirs there, but they did use the 5.68 percent as opposed to the 7.1 percent.

So, next slide, please. So, I kind of said most of this when I was talking to the graph there, but mine is consistent with common practice, long-term averages of 4.2 percent, current forecasts. And LEI, theirs is inflated because they used the recent 10, 20 and 30-year periods to estimate the MRPs. Now, as I've mentioned in my evidence, the last 30 years has been kind of an unprecedented period for U.S. stocks. Okay? Some would argue that's why they have slightly inflated PE ratios and could be due for a slight correction, although who knows if that will happen. But the bottom line is the most recent 10-year period has been extremely, extremely high and they weight that period three times. Right? Because it's in their most recent 10 years, it's in their most recent 20 years, it's half of that sample and it's also one-third of the sample with the most recent 30 years.

Concentric comes up with a historical of 5.68 percent. Again, you know, that's out of line with that 4.2 percent, you know, that long-term evidence, even though they have huge overlap in period, and that's because they use income only returns as opposed to total returns on bonds, and that's not the appropriate approach.

Nexus on the other hand completely ignores -- says historical evidence is not important and we look at the

forward-looking U.S. MRP and get 8.83 percent, along which they estimate with an expected long-term growth rate to infinity of 11.49 percent. I would add that they have used the sustainable growth model to come up with that estimate even though I get criticized for using the sustainable growth model, but it's clearly widely used in practice. I'll come back to that later. The other thing is here is an example of a model output and the I heard Nexus speaking this morning that models, you know, you can't always rely on the thing, but here is an example where the model output to me just makes absolutely no sense. They expect North American companies, utilities for that matter, to grow at more than almost three times expected nominal GDP growth. So, let's just kind of conclude on the CAPM. Sorry, we have the betas to go through yet.

Sorry, next slide. In my mind I said next slide. So, here on this slide you see that I provide the long-term Canada beta estimates that I produced in Appendix B or C. Also, the 0.55 that was over the 1970 to 2020 period from Sikes 2022 study, and I used the 0.45. I kind of adjust up that long-term average for Canada, not necessarily to bring it in line with the U.S. but just based on judgment. LEI used 0.69, as I heard them speak this morning, we're in agreement on the use of raw betas. And actually they provided an interesting slide that showed, in fact, that since 1970, betas have never been anywhere near 1 with an average of 0.5. I think the highest was just over 0.8. So, I thought that was very interesting because their

sample goes back to 1968, I think, which is a long period. So, they made the correct argument that why would you then use the Blume adjustment to bring that beta towards 1 when they don't go towards 1? If you're going to adjust anything add it to .5, the long-term average.

Anyways, Concentric and Nexus, both use adjusted betas, which I disagree with. Also, I would note that the betas for these other groups are higher by definition because of that heavy weighting in U.S. firms.

So, if we go to the next slide, I think I'm -- sorry, before I get to that, I'll come back to the next slide. It kind of sums up what I did. The next slide, please. This is a chart, and this is actually, if you look at the top one, it's very similar to the one that LEI included in their presentation today. And if you look at it, it looks really strange because you see the beta for utilities going slightly below 0 in 2001, 2002. Right? So, if we're to use, we're going to ignore historical information and long-term trends and just look at the estimates today and that's the world today, remember these are estimates, then back in 2002 our CAPM estimates would have been we're going to use the risk-free rate. Okay? That doesn't seem right to me. I would never have done that. I would have said, no, that's a blip. The blip was caused by the IT boom then crash. So, the betas across all the market has to be 1 by definition. Okay? So, if the betas for the IT is going to 2, then the banks, which typically has a beta of 0.9. They're at 0.5 and the utilities that have betas of .4,

that's where they're going to 0 there. Right? So, my point is, and as Nexus mentioned earlier, using the models is one thing, but applying judgment to what they spew out is another thing. So, if I get beta estimates like that in 2002, I would probably be using 0.4 or .5, somewhere in there like I am today. And you can see similar in the U.S. evidence, the other point of this graph is to show you that nowhere near did they ever come near 1 in Canada or the U.S. over the period.

So, to kind of conclude on betas go the next slide, please. And you see I used .45 and I've talked about the reasons for the others and pointed to some evidence. So, we can skip on to the next slide very quickly here. As a result of those issues that I talked about using the U.S. forecast for RF, using U.S. weighting in the betas, and the adjusted betas, and the MRPs not being reasonable in some cases, you can see that again comparing their CAPM estimates to the market of seven and a half percent or somewhere between 6.1 and 8.5, they're all well above it.

On to the DCF, the next slide, please. Here, the main issue, I don't think there's huge issues in terms of estimating dividend yield, but the main difference in the model estimates will be with respect to future growth. I use the sustainable growth rate that's in standard practice by analysts in almost every finance textbook, including my own, it's in the CFA curriculum, Nexus used it in their MRP estimate even. But LEI, Concentric and Nexus, first of all, they're all focused heavily on U.S. utilities, and

second of all, they use sell side analyst growth forecasts. It's important to note they're sell side analyst growth forecasts. Buy side analyst growth forecasts would never be that optimistic, but you never see them. They're proprietary, so the pension funds and the large institutional investment managers, their growth funds, I have seen some of their reports, but they're always proprietary and they're using, like, 3, 4, 5 percent, like most analysts do, not these extremely high 9, 10 percent that you see, and you see me citing a study there by Easton and Sommers that shows the optimism bias in growth forecasts.

So, if we go to the next slide, then, the other point to note in the single stage DCF, that growth rate you're assuming is supposed to be to infinity, the way the model is constructed. Everyone, you know, downplays that, I guess, but if you have companies that are going to grow 10, 6, 7 percent higher than the nominal growth GDP, especially mature operating utilities. That's a handy trick. They're going to subsume the economy, mathematically you can show that, but that's a technical point.

Anyways, as a result of that, I thought I would note that in Alberta, they consistently reject the use of growth rates above the expected nominal GDP growth rate in their estimates.

So, if you turn to the next slide, with regard to multistage, I use the H model, which assumes linear gravitation to a long-term rate over two or four years.

LEI and Nexus don't use any. Concentric uses a multistage that has 10 years of high growth followed by to infinity. So, five years at the higher growth that's based on analysts' estimates, then linearly decreases over the next five years. And then GDP at the end. So essentially, this model inherently assumes higher growth than GDP from now to infinity.

Next slide, please. So put all these together and again, you see that my estimate is right in -- well, a little bit high, actually, if I think of 7.5 percent for the market, but slightly below. And the other ones are above.

So, let's go to the risk premium models. As mentioned before, I used the bond yield plus risk premium. Company bond yield plus the risk premium, that intuition I talked about before. And it conforms to the basic principle that investors require high returns for assets with greater risk. And that company bond yield already has a risk premium built into it. It is determined in the bond market, which many would argue is much more efficient than the stock market. So, that's one of the advantages of it.

Flip to the next slide, please. The risk premium models used by LEI, they use an equity risk premium approach. They use the risk-free rate, which loses the advantage of the information in the bond market in terms of spreads. And then they estimate an ERP, and I am not quite comfortable with the estimate, of the 5.5, although it's not completely out of line with -- well, it's better.

Let's put it that way.

So let's go to the other two risk premium models, and it is Concentric and Nexus who get around their estimates, 10 and 11.08. These are based on regressions of U.S.-allowed ROEs, and U.S. government yields and U.S. corporate bond yields. The U.S.-allowed ROEs are not market data, they are not determined at regular hearings all the time. Sometimes it's only upon appeal. Sometimes they are, sometimes they have formula, sometimes they are not. But it's not something that day-to-day market data. Like every year, when you update it and you look at the A-rated utility spreads and the risk-free rates.

Also, the use of U.S. government yields and corporate yields, although there could be a relationship there with the Canadian costs of equity, I do not believe that is so.

So, as a result, if you go to the next slide, I can finish up this discussion fairly quickly, hopefully not too quickly for the court reporter. But, again, we see that their estimates are above the expected return for the market.

A couple of other things about the formula here, if we can just go to the next slide? Can we go to the next slide, please? Yes. So, kind of a repeat of what I said before, about the use of actuals versus forecasts. But there's also another point here in terms of estimating the LCBF and utility spreads. I prefer a point estimate as to looking at 30 days, 90 days or even 365 days, as I think one expert recommended, just because it reflects the most

current information. Okay?

If I take the yield and the yield spread 90 days ago, it doesn't reflect the fact that the Bank of Canada reduced the yield -- you know, the bank rate yesterday. Today's rate does. Okay? So I think overall you are going to see that using the most current is most reflective.

Next slide, please. So, that is basically saying that, so I'll just kind of flip over it. I recognize I am getting around the end of presentation time here. So, if we go to the next slide. So, that is that point.

The other is that evidence, and this is from one of the figures in Appendix A of my show, that show that 40 percent upward bias by using forecasts as opposed to actuals.

So we could go to the next slide now, having made that point, and then I just have two more points to make. And I recognize I am the last person of the day.

So the current adjustment factors for both the LCBF and utility adjustment factors are 0.5. I recommend to increase that to 0.75. I provide some evidence in that figure; if we had more time, you can always look at it later if you're really bored. But it shows that when you use 0.75 adjustment factor, it is a little better; that spread in allowed ROE to Rf and A-rated utility yields, not quite as big, but also not at extremely volatile in the allowed ROE, okay? - less so than if we used 1.0, for example.

The adjustment factors, if you go to the next slide, I

think these -- I don't even know what these mean in terms of these regressions. They're regressing U.S.-allowed ROEs on U.S. government bond yields and U.S. corporate bond yields. And I really, as I said, U.S. allowed ROEs; it's not even market data, and I don't know quite what that has to do with the impact of long-term Canada bond rates in Canada, and A-rated utility spreads on the cost of equity for Ontario utilities. I just think it's nice you got the coefficients, but I don't really know what they mean.

Next slide, please. The equity ratio recommendations, I did, as one of the groups mentioned. I recommended that Hydro One could be reduced to 38 percent, and gradually to 36 percent. So it was in line with my recommendation of 36 percent for EGI last year, when actually at those proceedings, it was actually sitting at 36 percent.

The recommendation and my 2023 evidence provides support for the 36 percent for Enbridge Gas, so I won't repeat it. But, for Hydro One Inc., you know, they have strong ratings, as you can see, by three rating providers. They are identified as having excellent business risk and low industry risk by S&P, reasonable regulatory support by DBRS Morningstar, and those are strengths.

They are able to attract debt capital at attractive rates around the A-rated utility rate and below some of the comparable operating utilities in Canada. And they have been allowed to -- they have been earning allowed ROEs at or above those allowed for the most recents. And also, they have strong credit metrics, with two of them falling

in the A-range and one consistently in the AA-range. So, there's room to move that down a little bit.

Finally, the last slide here, and then I will conclude. So Concentric on the other hand recommends an across-the-Board increase in 45 percent. And, as discussed before, mainly they're arguing that to bring it in line with the U.S. utilities. They don't really provide any metric analysis to suggest that that is necessary or that they're having trouble attracting capital today. And, as mentioned before, it is inconsistent with the recommendations for allowed equity ratios in Newfoundland and in Alberta.

So I apologize if I went over, but that's it for me. Thank you.

QUESTIONS BY THE BOARD

MR. SARDANA: How does Hydro One's price to book compare with U.S. utilities' price to book? You mentioned that Hydro One is over 2.0.

DR. CLEARY: Yes.

MR. SARDANA: And I can accept that. But how does that compare to, say, you know -- and I am just throwing this out of the air -- American Electric Power or, you know, some large U.S. utilities?

DR. CLEARY: Yeah. I think it's right on line and actually, one of the -- if you look to the section in my evidence that does it, I think the average for the U.S. over the 2017 to 2023 period for the U.S. was 2.05. And then Hydro One was 2.04, so it's kind of bang on, in that

sense.

MR. SARDANA: So in your estimate, would there be economic rents being earned across the board? Or is this just the way these utilities operate?

DR. CLEARY: Now that's a great question. The answer is apples and oranges. That's why the U.S. equity, that's why I argue the U.S. utilities are riskier. By saying they are a comparable investment is not the case. They are perceived as being riskier, hence their investors require a higher return on them than regulated operating Ontario utilities.

And so it's not quite apples and oranges but it's, you know -- it's different brands of apples you are comparing, for sure. So...

MR. SARDANA: It is certainly a fruitful discussion.

DR. CLEARY: Yeah.

MR. SARDANA: Thank you.

DR. CLEARY: Good one.

MR. JANIGAN: Commissioner Anderson.

MS. ANDERSON: So what you have said is that the spreads between ROE and yields have been increasing. What's your take on why?

DR. CLEARY: Yes, thank you. I think it's something I touched upon briefly in my presentation. I think there's a fair bit of inertia that's built into it, because we come to these proceedings and you look around and there's pressure from debt rating agencies to be viewed as a support of regulatory body. Right? And okay, so then but

even when the market data is telling you something different, you don't want to be that different from the others. I think there's a little bit of a resource mismatch at a lot of these proceedings, certainly the ones I've been involved in, in terms of the experts that they have provided. Sometimes in Alberta there's three on the other side, sometimes there's me and, you know, and I asked a question of them one time and one time one of the groups used 2500 hours. And, you know, if I told the utility consumer advocate I need 2500 hours, they would, you know, just look at me like I have got five heads. But I think a lot of it just has to do with it just seemed right when it was nine-and-a-half percent. Even when the bond rates went from, you know, 6 percent seemed right in 2004 or maybe even higher. Right? But 3 percent seems closer to right now, or 3 to 4. Right?

And that's not, probably not going to change a whole lot. Right? We saw them go up when we had the inflation spike, but now the inflation is coming down, we're seeing the bond yields. They don't go toe-to-toe with the Bank of Canada rate. Right? Or the Fed fund rate. But the bond yields, they're long-term investment and they're rooted in inflationary expectations. Right?

And now that those inflationary expectations are underlined, there's a link to the Bank of Canada rate, but they're more concerned with -- sometimes you see the Bank of Canada rate go up and bond yields go down because they think that's fighting inflation. Right? So it's

definitely not, like, a 0.8 correlation or something.

So there's a, you know, it's hard. You're used to nine-and-a-half percent, and you just, you know, because I can remember in Alberta in 2013 it went to 8.3 and you could just -- it seems weird, but it was still too high in my opinion, of course. But, you know, it did come down and, you know what, all the utilities maintain their A-ratings and, you know, some had A-minus and they were still able to attract capital at good rates and so on and so forth. The world didn't come crumbling down, it just brought them more in line. Then things change and, you know, the rates change. So...

MS. ANDERSON: Okay. So, you talked about the utilities in the U.S. being higher risk, so there's another why question for you. Why are they higher risk?

DR. CLEARY: Well, it's a great question and of course one I get a lot, obviously, every time I'm involved in these proceedings. Because a lot of those publicly listed ones are holding companies. And I do recognize the same is true for the Canadian holding companies. Right? But also I think the regulatory setup in the U.S., and I'm certainly not an expert on it like some of, you know, the U.S. colleagues involved in these, but I think it's a different kind of scenario than the ones in Canada. I think actually, I can't remember, someone mentioned this morning specific risk to California and Georgia and, you know, like that. Okay. Well, in Canada we could have some jurisdictions like that, but, you know, Ontario is not one

of them, Alberta is not one of them. Right? You know, and so, therein lies some of the issues. Right? And I don't think BC is either. So, there's that part of it. And they're in the U.S. capital markets and there's no doubt there's integration of the capital markets.

But the bottom line, and I showed in my evidence is that there's a home bias. In Canada we are 3 percent of the equity market, 3 percent of the fixed income market globally, yet our investors own, average investor in Canada, 42 percent in equity, of Canadian equities. I mean they talk about the -- even the big pension plan is 25 percent and they get criticized for that and say, but actually we're overweight, you know, like a lot. Right? And then the fixed income market is really home bias. It's, like, 84 percent. So, most of the Canadian, you know, if you float bonds in Canada, most likely, and someone mentioned earlier, I think one of the Board members, you know, that when Ontario companies issue bonds, they're over-subscribed. Right? And that's indicating these are pretty high quality bonds. And you ever notice we get that A-rated utility index? That's lower than the A-rated index. Right? That shows you something. It's interesting to note if you actually download the two, it's not a big difference, but it shows you that A-rated utilities are viewed as less risky than just your average A-rated company, and that's because, you know, monopoly, you get to pass through cost to customers, you know, if you're in a strong geographic area, you know, those things

that make them less risky than the average company in the market that has to fight for demand, that doesn't get to pass on their costs to the consumers and so on and so forth. Right? But that's a big part and, you know, as to why, I think the betas are a little bit higher because of the holding company nature of them. You see that also in some of the Canadian holding companies. Enbridge Inc., I don't think, is a good one because it's too risky because they have some regulated, you know, operating utilities, low risk, like EGI. Right? But then they also have a lot of pipelines in a lot of U.S., so in some sense I would view that they use some of that stability from their cash cows with the lower risk and then they undertake more risky operations, which is their prerogative. Right? But then that means they're going to get lower debt ratings, you know, than some of their operating companies. I don't know. Sorry, long answer. I don't know if I answered your question or not.

MS. ANDERSON: One of the issues seems to be the inclusion of the flotation costs in the debt and your recommendation is to put it into the actual rate, but you also used the 0.5 and then we did hear that some people thinking that was a bit rich and I don't see that you have commented on the use of 0.5.

DR. CLEARY: Yes. Thanks. That's also a good question, because I thought about it a lot as I read the evidence. And LEI makes a good point that it is a little bit high because companies don't issue equity on a regular

basis. They do issue debt on a more regular basis, although I think there was an IR response maybe even for the big ones, one to two times a year, you know, probably not more than that, in some years, none. Right? Now, the flotation costs on debt would be lower probably than 50 basis points. The flotation costs on equity would be higher. Right? You know, 1 to 2 percent depending on, you know, the market. Right?

So, if you recognize that they're going to issue the equity -- and remember the ROE is supposed to be the cost of equity. I think it's appropriate to include a cost in there, but I think if you use 2 percent, that would be kind of assuming they're issuing every year. Right? So, 50 basis points maybe is a reasonable compromise, and maybe also reflecting that you're maybe paying a little bit, maybe 20 bps on debt issues during the year, too. So that was my thinking on that, although I appreciate LEI's approach as well.

MS. ANDERSON: Okay. Thank you.

MR. JANIGAN: Yes, Dr. Cleary, I just have one question and it deals with energy transition. And energy transition has been cited as a possibility hazard in the future in the event that ROEs do not match the ability of utilities to raise the appropriate money to spend in that area. What is your opinion on that?

DR. CLEARY: Yes. Thank you. That's a great question because I did hear it come up this morning, so I kind of thought about it on my drive in here, and actually in

preparing my evidence as well, I should say.

So, I have a couple of different thoughts on that. The first is we discussed this at quite some length during the EGI rebasing proceedings last year, and I think, you know, the -- I don't know there's ever a consensus. But anyways, my takeaway was that, yes, there's energy transition coming. It's not coming today. It's starting or it's in process. It's moving fairly slow, but it's moving. So, that creates both opportunities and risk, and the opportunities, of course, are increased demand. Right? The risks, okay, are they not operationally efficient? Can they not deal with these increase in demand? I don't see a lot of evidence of that. Are they going to have trouble attracting capital? No evidence of that. If their issues are over subscribed in their price-to-book ratio, using Hydro One, the only one I can reference, 2.04, no indications of that. So, the argument you need to do this to prepare for it, okay, so I don't know why today's ratepayers need to finance financing that the utilities may have to come up with three or four years from now, especially when there's no indication they're having problems financing it today. Right?

So, if their bonds are oversubscribed today, why do they need to increase their equity thickness and increase their ROE because they can clearly, if they're oversubscribed, they can issue more debt? And if their debt is oversubscribed, they can probably issue more equity, too.

And if we see that the rates are out of line, then it's wrong. But I don't think it's something that you need to do preemptively, and let five years of consumers pay for five years for risks that may or may not materialize.

You also have to realize that growth opportunity. If the investors think it's a great growth opportunity, they may not want a higher compensation for it. You know, they may say, they've got all this growth opportunity, they have made solid plans that are in place; I could actually accept a lower return on them, because, as was mentioned by one of the Board members this morning -- sorry, I can't remember -- that includes an increase in your rate base and an increase in future income and potential increase in dividends. Right?

So, it could have exactly -- you know, it could have the opposite effect, or it might just be we have already factored a lot of that into what we are charging you today which, if the markets are efficient, you would assume is the case. And so it's not going to be impacted.

MR. JANIGAN: Okay. Commissioner Anderson had another question to ask.

MS. ANDERSON: Sorry, I forgot to ask my question about size and the market in Ontario. And it was twigged by your slide on the Newfoundland case, and the fact that the argument was that that faced significant risk because of their smaller size. And here in this province we have 70-ish, some very small, some larger.

DR. CLEARY: Mm-hmm.

MS. ANDERSON: We heard this morning that that was more of a policy, a social policy decision as to how you deal with that -- I mean, not mostly, but partially.

So what's your take on the fact that we have some with a few thousand customers, like 3,000 customers, and some with over a million?

DR. CLEARY: Yes. No, it's a great -- because you have, you know, the Big Four, if you will. Right? And then you have a lot of others. I mean, there's some other big ones, but I am thinking, like, Hydro One, EGI and OPG. And then you have, like, Toronto Hydro and Ottawa. And they are big players, as well. But then you do have a lot of smaller ones.

And my take on that is that, yeah, they do. You know, size is a factor. But one of the things you can do to adjust for that is through their equity ratio, is one way of adjusting for it. And I think -- I can't remember who said it, but it was interesting, saying even if you increase their allowed ROE, they may not be able to make it anyway.

And that is kind of consistent with the policy of, you know, setting a flat ROE and adjusting the equity ratios as appropriate. So I believe that's a reasonable practice.

MS. ANDERSON: And then the question is should you do that?

DR. CLEARY: Should you what?

MS. ANDERSON: Should you adjust the capital structure based on the size because, you know, that's -- I guess

that's the policy question part of it.

DR. CLEARY: Yeah. I think that's an appropriate approach to doing it, if it -- not just because they're small. If they are very profitable in a great region, that's one -- you know, what I mean.

But if that's creating an excess risk that you see in their ability to operate and attract capital, then I would say yes, that would be an appropriate adjustment.

MS. ANDERSON: Thank you.

MR. JANIGAN: Okay. Well, thank you, very much, Dr. Cleary, and thanks to all the experts and the counsel and support that appeared today. This proceeding was very helpful to the Panel members, and I hope it's helpful to the parties who are participating in this hearing, which will take place later this month. So, thank you.

--- Whereupon the proceeding adjourned at 2:16 p.m.