January 30, 2018

BY RESS AND COURIER

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Box 2319
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Alectra Utilities – Application for Distribution Rates and Other Charges Effective January 1, 2018 (EB-2017-0024) – Applicant Reply Submission

In accordance with Procedural Order No. 3, issued by the Ontario Energy Board on November 17, 2017, please find enclosed Alectra Utilities' Reply Submission. The Final Reply Submission has been filed on RESS and a copy served on all parties.

Two hard copies will follow via courier.

If you have any questions, please do not hesitate to contact the undersigned.

Yours truly,

[Original Signed By]

Indy J. Butany-DeSouza, MBA
Vice President, Regulatory Affairs
Alectra Utilities Corporation

Encl.

cc All Parties, Crawford Smith

2018 ELECTRICITY DISTRIBUTION RATES

Alectra Utilities Corporation

EB-2017-0024

APPLICANT'S REPLY SUBMISSION

January 30, 2018

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

AND IN THE MATTER OF an Application by Alectra Utilities Corporation to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of January 1, 2018.

REPLY SUBMISSION OF ALECTRA UTILITIES

January 30, 2018

A. INTRODUCTION

Alectra Utilities Corporation ("Alectra Utilities" or the "Applicant") filed an application with the Ontario Energy Board (the "OEB") on July 7, 2017, under section 78 of the *Ontario Energy Board Act, 1998*, seeking approval for changes to its electricity distribution rates for each of its Horizon Utilities, Brampton, PowerStream and Enersource rate zones ("RZs") to be effective January 1, 2018 (the "Application").

In accordance with Procedural Order No. 3, issued by the OEB on November 17, 2017, Alectra Utilities filed its Argument-in-Chief on December 22, 2017. Submissions were filed on January 16 and 17, 2018 by OEB staff, as well as six intervenors – the Power Workers' Union ("PWU"), the Vulnerable Energy Consumers Coalition ("VECC"), the Association of Major Power Consumers in Ontario ("AMPCO"), the Consumers Council of Canada ("CCC"), the School Energy Coalition ("SEC") and the Building Owners and Managers Association of Greater Toronto ("BOMA"). This is Alectra Utilities' Reply Submission.

B. OVERVIEW

In the sections that follow, Alectra Utilities responds to the submissions of OEB staff and the intervenors in detail, issue by issue. Here, Alectra Utilities provides an overview of those submissions and sets out its views of the important considerations for the OEB in deciding the Application.

Annual Distribution Rate Adjustment

OEB staff was the only party to file submissions in relation to the appropriateness of the annual distribution rate adjustments proposed by Alectra Utilities for each of its four rate zones. OEB staff agrees with the proposed adjustments. These should be approved.

Incremental Capital Module

This is an important Incremental Capital Module ("ICM") application. In it, the OEB is being asked by opposing parties to "rethink", or significantly modify its *Handbook to Electricity Distributor and Transmitter Consolidations*, dated January 19, 2016 (the "MAADs Handbook") generally and the December 8, 2016 Decision and Order of the OEB on the Alectra MAADs application in EB-2016-0025 (the "MAADs Decision"). This invitation should be rejected. It would be unfair to Alectra Utilities. It would also undermine completed transactions, current negotiations by various parties in the province that are developing transactions relative to the policies and guidance set out in the MAADs Handbook, and, inevitably, the OEB's stated objective of promoting consolidation in the electricity distribution sector.

In the MAADs Handbook, the OEB confirmed that the ICM is available to consolidating distributors. It repeated this confirmation, over intervenor objections to the contrary, in the MAADs Decision. The OEB reiterated that the ICM affords consolidating distributors, such as Alectra Utilities, an opportunity to finance capital investments without having to rebase earlier than expected. Notably, the OEB did not limit the availability of ICM to post-2019,[1] despite knowing that this was the earliest date by which Alectra Utilities could file a consolidated DSP,[2] nor did the OEB impose any restrictions on the types of projects that would qualify for incremental funding. Despite being aware of the potential need for Alectra Utilities to file multiple ICM applications, the OEB did not advise that Alectra Utilities should be required to file a Custom IR application for its three eligible rate zones (Brampton, PowerStream and Enersource). Rather, in all material respects, the OEB confirmed its relevant guidance as set out in the MAADs Handbook, the *Handbook for Utility Rate Applications*, dated October 13, 2016 (the "Rate Handbook"), the *Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, dated September 18, 2014 (the

[1] The date suggested by some intervenors.

[2] Alectra Utilities MAADs Application (EB-2016-0025), Oral Hearing Transcript, Vol. 1, September 7, 2016, p.119.

"ACM Report"), the *Report of the Board – New Policy Options for the Funding of Capital Investments: Supplemental Report*, dated January 22, 2016 (the "Supplemental Report"), as well as Chapter 3 of the OEB's *Filing Requirements for Electricity Distribution Rate Applications – 2016 Edition for 2017 Rate Applications*, dated July 14, 2016 (the "Filing Requirements"). Alectra Utilities has not proposed any departures from those policies or requirements in this Application.

This does not mean that Alectra Utilities should be entitled, automatically, to incremental funding. It is however to point out that it ought to have the opportunity to make its case for that funding. To read the submissions of parties, Alectra Utilities should have no meaningful opportunity at all.

Alectra Utilities has a total of 22 proposed ICM projects across the Brampton RZ, PowerStream RZ and Enersource RZ. These investments address important needs with respect to Alectra Utilities' distribution system, variously driven by mandatory requirements; the need to update assets to meet applicable safety and operating standards; the need to maintain or enhance reliability to meet customer expectations; the need to increase system capacity to meet expected demand; and the need provide access to distribution service. The evidence establishes that each of the projects is discrete and satisfies the OEB's established criteria of materiality, need and prudence and otherwise accords with OEB policy and requirements. In Alectra Utilities' submission, the full amount proposed for recovery through the ICM should be approved: $6,800,377 for the Brampton RZ; $25,891,795 for the PowerStream RZ; and $24,247,022 for the Enersource RZ.

Enersource RZ DSP

As part of this Application, consistent with the *Filing Requirements*, and to support the request for incremental capital for the Enersource RZ, Alectra Utilities filed a DSP for the Enersource RZ for a five-year term from 2018 to 2022.[3] It includes sufficient information to support the proposed ICM for the Enersource RZ and provides justification for proposed expenditures relating to the Enersource RZ distribution system and general plant for the 2017 bridge year and the 2018 to 2022 period, including investment and asset-related maintenance expenditures. The few complaints that have been made by parties should be rejected. These are either simply wrong (e.g., the suggestions that the DSP is a pre-

[3] In the Oral Hearing for the MAADs Application, Alectra Utilities' witnesses testified that a consolidated DSP would be filed by April 2019. This DSP, once filed and reviewed by the OEB, will effectively update and replace the Enersource 2018-2022 DSP.

merger document, that Vanry's report should not be relied upon or that the Enersource RZ DSP does not reflect customer preferences), or are based on the argument, already rejected and discussed above, that the OEB should now require an all rate zone, consolidated DSP.

Customer Engagement

As discussed in the Application, interrogatory responses, the Technical Conference and Argument-in-Chief, Alectra Utilities engaged Innovative Research Group ("IRG") to undertake an extensive customer engagement program in respect of all four rate zones to understand the priorities and preferences of its customers. The engagement followed the OEB's guidance. There is no question that the consultation was successful, gathering by far the largest amount of customer feedback ever collected by an Ontario utility.

Despite this result, many parties take issue with Alectra Utilities' customer engagement efforts. Fundamentally, these complaints rely upon an erroneous recitation of the process and incomplete or selective references to the actual questions asked of customers and their responses. On any fair, complete reading of the IRG Report and evidence, the message from customers is clear: while concerned with the total amount of their electricity bills, most customers support some form of investment program that ensures a consistently reliable and modern distribution system that addresses growth and system demands.

Capitalization

In Procedural Order No. 3, the OEB rendered its decision on the final issues list for this proceeding. The OEB determined that it would add a new issue relating to the change in capitalization policy. Given the timing of the remaining steps in the proceeding, the OEB also made provision for the establishment of three new deferral accounts "to track the change in capitalization" for the Horizon, Enersource and Brampton RZs. However, the OEB concluded in that order, by expressly noting that "[t]he nature of any disposition of these accounts is not being determined at this time", that submissions in this respect would be heard as part of final argument.

As Alectra Utilities has argued, the capitalization policy change is a non-cash event that had no impact, and will have no impact going forward, on the underlying cost of utility business. Further, OEB policy does not support any claim for rate adjustment at this time. Specifically, any benefit arising from the merger and within the rebasing deferral period, perceived or otherwise, clearly accrues to the account of shareholders.

More particularly, in the MAADs Handbook, not only does the OEB contemplate that the benefits of a transaction will be received by the shareholder (at least during the rebasing deferral period), but that the costs will be borne by it, as well:

> Incremental transaction and integration costs are not generally recoverable through rates. Distributors have indicated that these costs are significant and that recovery of these costs can be a barrier to consolidation. To address distributors' concerns, the OEB issued a report on March 26, 2015 titled "*Rate-making Associated with Distributor Consolidation*" (2015 Report). In this report, the OEB has provided the opportunity for distributors to defer rebasing for a period up to ten years following the closing of a consolidation transaction. This deferred rebasing period is intended to enable distributors to fully realize anticipated efficiency gains from the transaction and retain achieved savings for a period of time to help offset the costs of the transaction.[4]

The OEB reiterated this in the MAADs Decision.[5] The capitalization policy change is a function of the integration; the savings or costs arising from integration are to the account of the shareholder as specified in the MAADs Handbook and, more recently, in the MAADs Decision.

As a result, the capitalization related deferral accounts should be closed and any amounts recorded reversed.

Surprisingly, SEC and BOMA were the only parties to respond to Alectra Utilities' argument on this issue. Most parties appear to simply presume the outcome of the decision. Their position wrongly overlooks the OEB's Procedural Order. Even SEC and BOMA's arguments fail to address the important, governing OEB policies and requirements discussed by the Applicant. These cannot be ignored. With respect to SEC's claim that Alectra Utilities is attempting to recover the capitalized amounts twice, it misunderstands what the Applicant has asked for or even could reasonably claim in a future, as yet unfiled, application. BOMA's claim that the capitalization change warrants z-factor treatment is similarly misplaced. In fact, nowhere does it even explain how this could be so.

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[4] MAADs Handbook, pp. 8-9.

[5] EB-2016-0025, Decision of the Board, December 8, 2016, p.16

C. CUSTOM INCENTIVE RATE-SETTING APPLICATION UPDATE

Issue 1.1

Is the Year 4 Custom IR Update proposed for the Horizon Utilities rate zone (RZ) complete and in accordance with the framework accepted by the OEB from the EB-2014-0002 settlement agreement and any applicable OEB policies, practices and requirements and, if not, are any proposed departures adequately justified?

Horizon Utilities' settlement agreement from its Custom Incentive Rate-Setting ("IR") Application (EB-2014-0002), approved by the OEB on December 11, 2014 (the "Horizon Settlement Agreement") provides for annual adjustments during the term of the Custom IR rate plan.[6] Alectra Utilities has applied for annual adjustments for the Horizon Utilities RZ related to the third adjustment in its 2015-2019 Custom IR rate plan term. These adjustments and Alectra Utilities' response to the submissions of OEB staff are set out below.

Changes in the Cost of Capital

In its Argument-in-Chief, Alectra Utilities indicated that it would update the Cost of Capital Parameters for the Horizon Utilities RZ to reflect the OEB's parameters for applications for 2018 rates, once these were available.[7] The OEB released its Cost of Capital Parameters on November 23, 2017.[8] OEB staff supports Alectra Utilities' proposed approach.[9] Alectra Utilities will update the Cost of Capital Parameters accordingly.

Changes to Working Capital

Alectra Utilities has updated the following inputs to its Working Capital Allowance in respect of the Horizon Utilities RZ:[10]

i) The Cost of Power and Global Adjustment were updated based on the OEB's Regulated Price Plan Report, issued April 20, 2017, for the period May 1, 2017 to

[6] See EB-2014-0002, Settlement Proposal, September 22, 2014, p. 29 ("Settlement Proposal"); Decision and Order, December 11, 2014, p. 3 approving the Settlement Proposal.

[7] Alectra Utilities, Argument-in-Chief, December 22, 2017, p. 7 ("Argument-in-Chief").

[8] Letter from OEB to All Licensed Electricity Distributors and Transmitters et al re Cost of Capital Parameter Updates for 2018 Cost of Service and Custom Incentive Rate-setting Applications, November 23, 2017.

[9] OEB Staff Submission, January 16, 2018, p. 6 ("OEB Staff Submission").

[10] Undertaking JT.Staff-1.

April 30, 2018 (the "April Report") and the Regulated Price Plan Prices and the Global Adjustment Modifier Report, issued June 22, 2017, for the period July 1, 2017 to April 30, 2018 (the "June Report"). Alectra Utilities applied an inflationary adjustment to determine the rates for the May 1, 2018 to October 31, 2018 and November 1, 2018 to December 31, 2018 periods;

ii) Retail Transmission Service Rates ("RTSRs") have been updated to incorporate 2016 demand, 2016 Hydro One Uniform Transmission Rates ("UTRs") and 2017 Hydro One Sub-Transmission Rates;

iii) The Smart Metering Entity Charge has been updated to incorporate 2016 Residential and GS < 50 kW customer counts, with no change to the Rate Rider;

iv) The ratio of RPP vs. non-RPP volumes has been updated for 2016 actuals;

v) The Rural or Remote Electricity Rate Protection ("RRRP") Charge has been updated to $0.0003/kWh as directed by the OEB[11]; and

vi) The Ontario Electricity Support Program charge of $0.0011/kWh has been removed from the Wholesale Market Service Charge in the Cost of Power.

OEB staff argue that the cost of power calculation (item (i)) cannot be inflated because it depends on the Toronto Hydro 2018 bill impact and the calculation should use the current approved RPP prices and global adjustment ("GA") modifier for the entire year.[12] OEB staff also submits that Alectra Utilities applied the global adjustment modifier to all non-RPP customers and that the GA modifier should only be applied to non-RPP customers that fall within the definition of "specified customer".[13] Finally, OEB staff indicated that since the 2017 UTRs have been approved, the RTSRs should be updated accordingly.[14]

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[11] EB-2017-0033, Decision and Order, December 20, 2017.

[12] OEB Staff Submission, p. 7.

[13] Ibid.

[14] Ibid.

Alectra Utilities disagrees with OEB staff's submission that there should be no inflation adjustment. An adjustment should be used to determine rates for the May 1, 2018 to October 31, 2018 and November 1, 2018 to December 31, 2018 periods. The OEB sets electricity rates for residential and small business customers twice per year, on May 1 and November 1. The OEB's most recent RPP Price Report establishes rates for the period ending April 30, 2018.[15] To determine the rates from May to December 2018, Alectra Utilities applied an inflationary adjustment. This is consistent with the Fair Hydro Plan. The *Ontario Fair Hydro Plan Act, 2017* established the framework for giving effect to the Fair Hydro Plan initiatives that the government has stated includes holding increases to the rate of inflation for four years.[16] Specifically, this includes lowering electricity bills and holding increases to the rate of inflation for the part of the bill that covers the cost of electricity.[17] Consistent with the intent of the Fair Hydro Plan, a 2% inflation adjustment was used to determine the May 1 and November 1, 2018 electricity rates for the purpose of the cost of power calculation.

Alectra Utilities agrees with OEB staff that the GA modifier should only be applied to non-RPP customers that fall within the definition of "specified customer" in the *Ontario Fair Hydro Plan Act*. However, OEB staff asserts that Alectra Utilities applied the GA modifier to all non-RPP customers.[18] This is wrong. The impact to the GA rates from the implementation of the Fair Hydro Plan was only applied to residential and GS<50kW non-RPP customers.[19] Alectra Utilities' undertaking response to JT-Staff-1 included an updated cost of power calculation filed as JTStaff1_Attach 1_COP Calculation. The '2018 Cost of Power Expense' Tab shows that the GA rates used for the residential and GS<50kW customer non-RPP classes differ from the rates used for the GS>50kW non-RPP classes.

Alectra Utilities confirms that the 2017 UTRs will be updated appropriately in its Draft Rate Order, to be filed following receipt of the OEB's Decision on this Application.[20]

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[15] OEB, Regulated Price Plan Price Report May 1, 2017 to April 30, 2018, dated April 20, 2017.

[16] See https://www.ontario.ca/page/ontarios-fair-hydro-plan

[17] *Fair Adjustment under Part II of the Act*, O. Reg. 195/17:, s. 1(7).

[18] OEB Staff Submission, p. 7.

[19] Undertaking JT.Staff-1.

[20] EB-2017-0280, Decision and Rate Order 2017 Uniform Transmission Rates, November 23, 2017.

Earnings Sharing Mechanism

The Horizon Settlement Agreement provides for a deferral account for earnings in excess of the OEB's annual approved regulatory return on equity ("ROE").[21] Earnings in excess of the approved ROE are divided on a 50/50 basis between (now) Alectra Utilities and Horizon Utilities RZ ratepayers.[22] Alectra Utilities has calculated an ROE of 9.877% for the purpose of the Earnings Sharing Mechanism ("ESM"). Earnings sharing in the amount of $695,975 is required for 2016, given that the calculated ROE is greater than the approved ROE of 9.19%.[23] Alectra Utilities had reported $662,467 in deferral account 1508 Sub-account Earnings Sharing Variance Account in the 2016 Reporting and Record Keeping Requirements ("RRRs") for Horizon Utilities. This amount was based on the best estimate at the time of the calculation. An update to the earnings for actuals resulted in a difference of $33,508 in the amount of earnings sharing, to the account of the ratepayer. In the Application, Alectra Utilities has proposed that this difference be reported in the 2017 deferral account balances and that the full amount be disposed of in 2018.[24]

OEB staff agrees that the ESM calculation is in accordance with RRR 2.1.5.6 and the Horizon Settlement Agreement. It argues, however, that the full balance of $695,975 should be recorded in the 2016 ESM deferral account to avoid future confusion as to the origin of the $33,508 in the 2017 deferral account balance.[25] Alectra Utilities disagrees with this approach.

Alectra Utilities therefore proposes to report the difference of $33,508 in the 2017 annual RRR Trial Balance. Alectra Utilities will identify that this amount relates to the 2016 ESM calculation to avoid confusion as to the origin of the difference.

Capital Investment Variance Account

The Horizon Settlement Agreement provides for a deferral account to refund ratepayers any difference in revenue requirement should in-service capital additions be lower than the approved

[21] Settlement Proposal, pp. 11 and 12.
[22] Ibid.
[23] Exhibit 2, Tab 1, Schedule 6, p. 4.
[24] Ibid., p. 6.
[25] OEB Staff Submission, p. 8.

forecast.[26] Alectra Utilities reported 2016 capital additions of $44.2MM, which is $3.1MM higher than the forecasted capital additions of $41.1MM.[27] Since the capital additions are above the forecast amount, no entry was made to the Capital Investment Variance Account ("CIVA"). OEB staff agree that the calculations for the purpose of the entry to the CIVA are consistent with the Settlement Agreement.[28]

Alectra Utilities therefore submits that the OEB should approve the CIVA calculation as set out in the Application.

Efficiency Adjustment

The Horizon Settlement Agreement includes an Efficiency Adjustment to incent Horizon Utilities, and now Alectra Utilities in respect of the Horizon Utilities RZ, to maintain or improve its cohort position based on the OEB's Stretch Factor Assignment.[29] The Efficiency Adjustment operates as a proxy stretch factor, in the event that Horizon Utilities is placed in a less efficient cohort than the starting point in any year during the Custom IR term.[30] Horizon Utilities' starting point was Cohort III. Alectra Utilities identified that the latest version of the *OEB's Empirical Research in Support of incentive Rate-Setting: 2016 Benchmarking Update for Determination of Stretch Factor Assignments for 2017* (the "Benchmarking Update"), issued on August 17, 2017, placed the Horizon Utilities RZ in Cohort III for the purposes of calculating stretch factors for 2018.[31] In the Application, Alectra Utilities indicated that no Efficiency Adjustment was appropriate for 2018.[32] In its submission, OEB staff agreed.

The Applicant maintains its submission that no Efficiency Adjustment is required.

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[26] Settlement Proposal, p. 27.

[27] Exhibit 2, Tab 1, Schedule 6, p. 11.

[28] OEB Staff Submission, p. 9.

[29] Settlement Proposal, p. 14.

[30] Ibid.

[31] OEB's Empirical Research in Support of incentive Rate-Setting: 2016 Benchmarking Update for Determination of Stretch Factor Assignments for 2017, August 17, 2017.

[32] Exhibit 2, Tab 1, Schedule 2, p. 13.

Special Studies Deferral Account

The Horizon Settlement Agreement included a deferral account to record costs related to the development of a Specific Service Charge study to determine the appropriateness of Horizon Utilities' Specific Service Charges.[33] Alectra Utilities confirmed that no studies have commenced and no costs have been recorded in this deferral account.[34] In response to interrogatory 1.0-VECC-2, Alectra Utilities stated that it is evaluating whether the second phase of the OEB's review in EB-2015-0304 will include a Specific Service Charges review and whether it would be in line with the intent of the approved settlement proposal.[35]

There were no submissions on this issue. Alectra Utilities confirms that no studies have commenced and no costs have been recorded.

Continuation of New Distribution Rate Design

Alectra Utilities has incorporated the third year transition adjustment to fully fixed distribution rates for residential customers in its proposed rates for 2018 for Horizon Utilities RZ.[36] Alectra Utilities conducted analysis on the 10th consumption percentile of energy consuming customers and followed the OEB's instructions to consider whether rate mitigation was required if there was greater than a 10% cost of distribution service. Alectra Utilities confirmed that the monthly service charge was not increasing by more than $4, nor would the customer at the 10th consumption percentile of electricity consumption have a bill impact of 10% or more.[37]

OEB staff agree that the methods used to calculate the fixed rate are in accordance with the OEB's report entitled *A New Distribution Rate Design for Residential Electricity Customers*, issued April 2, 2015.[38] No mitigation is required.

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[33] Settlement Proposal, p. 56.
[34] Exhibit 2, Tab 1, Schedule 2, p. 13.
[35] Response to Interrogatory 1.0-VECC-2, p.1.
[36] Exhibit 2, Tab 1, Schedule 4, p. 1.
[37] Ibid., p. 7.
[38] OEB Staff Submission, p. 10.

Issue 1.2

Have the revenue to cost ratios for the Horizon Utilities RZ been appropriately adjusted to reflect the OEB's decision in the EB-2015-0075 proceeding?

Alectra Utilities has asked for approval to reduce the 2018 Street Lighting Class' Revenue to Cost Ratio ("RCR") by 6.6% to 106.66%.[39] The OEB directed Horizon Utilities, in its 2016 Custom IR Annual Filing, to reduce the RCR by 6.6% as a gradual change to have the RCR at 100% in 2019.[40] The effect of the 2018 reduction in the RCR for the Street Lighting Class was a revenue deficiency. The associated revenue deficiency was then allocated by way of equal percentage to all rate classes that were below 100% RCR, with the exclusion of the Standby Class.[41]

OEB staff agree that the proposed rate design is consistent with the OEB's Decision and Order in Horizon Utilities' 2016 Annual Filing (EB-2015-0075) and the OEB's policies.[42]

Alectra Utilities submits that it has implemented the changes to RCR as directed by the OEB in its 2016 Annual Filing and that its approach to implementation should be approved.

D. INCENTIVE RATE-SETTING MECHANISM SCHEDULES AND MODELS

Issue 2.1

Are the IRM Model filings for the Brampton, Enersource and PowerStream rate zones in accordance with OEB policies, practices and requirements, and if not, are any proposed departures adequately justified?

Alectra Utilities' Incentive Rate-Setting Mechanism ("IRM") Model filings for the Brampton, PowerStream and Enersource RZs have been completed in accordance with applicable OEB policies, practices and requirements. At the time of filing the Application, the 2018 OEB Rate Generator Models for IRM applications were not available. Alectra Utilities developed models for the IRM for use in the Application that were based on the most recently available models from the OEB. In connection with Alectra Utilities' request for approval of distribution rates and other charges for the

[39] Exhibit 2, Tab 1, Schedule 4, p. 6.

[40] EB-2015-0075, Decision and Order, December 10, 2015, p.6.

[41] Exhibit 2, Tab 1, Schedule 4, p. 4.

[42] OEB Staff Submission, p. 11.

Brampton, PowerStream and Enersource RZs pursuant to the Price Cap IR regime, effective January 1, 2018, Alectra Utilities has completed its IRM Models for each of these rate zones.[43]

Price Cap Adjustment

Alectra Utilities applied a stretch factor of 0.3% for the Brampton and PowerStream RZs, and 0.15% for the Enersource RZ, each in accordance with the August 4, 2016 PEG report.[44] The OEB issued the updated Stretch Factor Assignments for 2018 IRM filers on August 17, 2017 in the Benchmarking Report. The Benchmarking Report placed Brampton and PowerStream in Cohort III and has moved Enersource to Cohort III for 2018.[45] Alectra Utilities will update the stretch factors in the IRM Models, accordingly.

OEB staff indicated that the stretch factor assigned to each of the Brampton, Enersource and PowerStream RZs is 0.3% and, subject to all necessary updates being made, OEB staff submits that Alectra Utilities' IRM schedules and models are in accordance with OEB policies, practices and requirements.[46]

Alectra Utilities agrees with OEB staff's submission, and submits that the stretch factor should be updated in the Draft Rate Order, which is to be filed following the OEB's decision on this Application.

Retail Transmission Service Rates

Alectra Utilities used the most recent UTRs available at the time of filing the Application in the IRM Models for the Brampton, PowerStream and Enersource RZs. On January 14, 2016, the OEB issued its Decision and Order in respect of the 2016 UTRs.[47] At the time of this filing, 2017 UTRs were not available. On November 23, 2017, the OEB issued its Decision and Order in respect of the 2017 UTRs.[48] On December 21, 2016, the OEB issued its Decision and Order in respect of Hydro One Networks Inc.'s ("HONI") application for electricity distribution rates and other charges beginning

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[43] Response to Interrogatory G-Staff-2, Undertakings JT Staff 2, JT Staff 5.

[44] Report to the OEB - *Empirical Research in Support of Incentive Rate-Setting: 2015 Benchmarking Update*, July 2016, pp. 23 and 24.

[45] Ibid., p.22.

[46] OEB Staff Submission, p. 13.

[47] EB-2015-0311, Decision and Order, 2016 Uniform Transmission Rates, January 14, 2016.

[48] EB-2017-0280, Decision and Rate Order, 2017 Uniform Transmission Rates, November 23, 2017.

January 1, 2017, which contain HONI's sub-transmission rates ("STRs").[49] These are the most recent STRs.

OEB staff indicated that since the 2017 UTRs have been approved, the applicable data for RTSRs will need to be updated in Alectra Utilities' models following the OEB's decision on the Application through the Draft Rate Order process.[50] Alectra Utilities agrees that the 2017 RTSRs should be updated in the Draft Rate Order, to be filed following the OEB's decision on this Application.

Residential Rate Design

Alectra Utilities has incorporated the third year transition adjustment to fully fixed distribution rates for residential customers in its proposed rates for 2018 for the Brampton and Enersource RZs.[51] Alectra Utilities has incorporated the second year transition adjustment to fully fixed distribution rates for residential customers in its proposed rates for 2018 for the PowerStream RZ.[52] Alectra Utilities conducted analysis on the 10th consumption percentile of energy consuming customers and followed the OEB's instructions to consider whether rate mitigation was required if there was greater than a 10% cost of distribution service, for all rate zones**.** Alectra Utilities confirmed that the monthly service charge was not increasing by more than $4, nor would the customer at the 10th consumption percentile of electricity consumption have a bill impact of 10% or more for the Brampton, Enersource and PowerStream RZs.[53]

OEB staff submit that, subject to all necessary updates being made to the IRM Models, Alectra Utilities' IRM schedules and models have been completed in accordance with OEB policies, practices and requirements.[54] Alectra Utilities agrees and submits that it has implemented the changes in a manner consistent with OEB policy and no mitigation is required.

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[49] EB-2016-0081, Decision and Order, December 21, 2016.

[50] OEB Staff Submission, p. 13.

[51] Exhibit 2, Tab 2, Schedule 3, p. 1; Exhibit 2, Tab 4, Schedule 3, p. 1.

[52] Exhibit 2, Tab 3, Schedule 3, p. 1.

[53] Exhibit 2, Tab 2, Schedule 3, for Brampton RZ, Exhibit 2, Tab 3, Schedule 3, for PowerStream RZ, Exhibit 2, Tab 4, Schedule 3, for Enersource RZ.

[54] OEB Staff Submission, p. 14.

Eligible Investments for Connection of Qualifying Generation Facilities

In Hydro One Brampton's 2015 Cost of Service Rate Application, the OEB approved Hydro One Brampton's request for funding of Renewable Generation Connection Provincial amounts included in its detailed Distribution System Plan ("DSP"), to be recovered through the IESO in relation to Renewable Enabling Improvement Investments and Renewable Expansion Investments from 2015 to 2019.[55] Alectra Utilities is requesting that it be permitted to collect renewable generation connection funding for the Brampton RZ of $117,963 in 2018 or $9,830 per month from all provincial ratepayers.[56]

In the 2016 Custom IR Rate Application, the OEB approved PowerStream's request for the funding of Renewable Generation Connection Provincial amounts included in its detailed DSP, to be recovered through the IESO in relation to Renewable Enabling Improvement Investments and Renewable Expansion Investments from 2016 to 2020.[57] Alectra Utilities is requesting that it be permitted to collect renewable generation connection funding for the PowerStream RZ of $266,079 in 2018 or $22,173 per month from all provincial ratepayers.[58]

Enersource filed a basic Green Energy Plan (the "GEA Plan") which was approved by the OEB in Enersource's 2013 Cost of Service Application proceeding.[59] Alectra Utilities is requesting that it be permitted to collect renewable generation connection funding for the Enersource RZ of $133,384 in 2018, or $11,115 per month from all provincial ratepayers.[60]

OEB staff agree that Alectra Utilities' renewable generation connection funding requests for the three rate zones have been correctly calculated.[61] Alectra Utilities asks that the 2018 funding amounts be approved.

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[55] EB-2014-0083, Final Rate Order, January 15, 2015, p.2.
[56] Exhibit 2, Tab 2, Schedule 7.
[57] EB-2015-0003, Decision and Rate Order, September 27, 2016, p. 2.
[58] Exhibit 2, Tab 3, Schedule 8.
[59] EB-2012-0033, Decision and Order, December 13, 2012, p.24.
[60] Exhibit 2, Tab 4, Schedule 8.
[61] OEB Staff Submission, p. 16.

Issue 2.2

Is Alectra Utilities' application of the Incremental Capital Module (ICM) criteria in accordance with the OEB policies, practices and requirements, and if not, are any proposed departures adequately justified?

Issue 2.3

Is the level of planned capital expenditures proposed in the ICMs appropriate and is the rationale for planning, prioritization and pacing choices appropriate and adequately explained and should the level of expenditures be approved by the OEB, giving due consideration to:

- ***customer feedback and preferences***
- ***productivity***
- ***compatibility with historical expenditures***
- ***compatibility with applicable benchmarks***
- ***reliability and service quality***
- ***impact on distribution rates***
- ***impact on OM&A spending***
- ***government-mandated obligations***
- ***the objectives of Alectra Utilities and its customers***
- ***the five-year Distribution System Plans***

Issue 2.4

Are Alectra Utilities' proposals regarding the ICM true-ups appropriate?

To more efficiently respond to the arguments raised by parties in respect of Issues 2.2, 2.3 and 2.4, these issues are considered together as follows.

As set out in Alectra Utilities' Argument-in-Chief, the ICM is a mechanism available to electricity distributors whose rates are established under the Price Cap IR regime.[62] The ICM is intended to address the treatment of a distributor's capital investment needs that arise during the rate-setting plan which are incremental to a materiality threshold. The ICM is available for discretionary and non-discretionary projects, as well as for capital projects not included in the distributor's previously filed DSP. It is not limited to extraordinary or unanticipated investments and it may be applied to projects that might be considered to be 'routine' or 'business as usual'.[63]

[62] Argument-in-Chief, p. 12.

[63] Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014, pp. 5-8 ("ACM Report).

Alectra Utilities has investment needs for the Brampton, PowerStream and Enersource RZs for 2018 that are not funded through existing distribution rates and therefore has filed an ICM application in respect of each of these rate zones.[64]

PWU supports Alectra Utilities' request for incremental funding.[65] OEB staff supports three of Alectra Utilities' projects – the Brampton RZ Pleasant TS True-up, the PowerStream RZ Road Authority YRRT Yonge St. Project, and the Enersource RZ Road Widening Project, QEW (Evans to Cawthra) – but otherwise opposes Alectra Utilities' request.[66] BOMA supports the funding of two projects through the ICM, namely the PowerStream RZ Mill Street MS835 Transformer Upgrade – Tottenham and the Enersource RZ City Centre Drive Rebuild (Walmart Cables).[67] All other parties oppose the Applicant's request for incremental funding through the ICM in its entirety.

Opposing parties and OEB staff make three types of arguments. First, they attack the availability of the ICM at all in the context of a consolidating distributor such as Alectra Utilities. Second, they advance a largely generalized critique of the specific projects for which Alectra Utilities seeks incremental capital funding. Third, they criticize Alectra Utilities' customer engagement efforts. Each of these types of submissions is responded to below.

Availability of ICM

OEB staff, SEC, CCC, VECC, AMPCO and BOMA all take issue with the application of the OEB's ICM policy to Alectra Utilities.[68] Each opposes what the OEB has already stated or determined on multiple occasions in prior decisions: that the ICM, as expressed in the March 26, 2015 *Report of the Board on Rate Making Associated with Distributor Consolidation* and in the MAADs Handbook, is available to consolidating distributors, such as Alectra Utilities.[69] Their opposition is such that it permeates all of their comments in relation to Alectra Utilities' request for ICM funding, including their project-specific complaints

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[64] Exhibit 1, Tab 1, Schedule 1, pp. 6-9.

[65] PWU Submission, January 16, 2018, para 12 ("PWU Submission").

[66] OEB Staff Submission, pp. 21, 27.

[67] BOMA Submission, pp. 2, 32 and 49.

[68] OEB Staff Submission, pp. 21-24; SEC Submission, pp 12-21; CCC Submission, pp. 9-10; VECC Submission, pp. 3-5; AMPCO, pp. 4-5; BOMA, pp. 9-12.

[69] *Report of the Board: Rate-Making Associated with Distributor Consolidation*, March 26, 2015, pp. 7-9.

CCC acknowledges that the "Board has, through a series of reports established policies regarding mergers and acquisitions" but argues that "strict adherence" to those policies may well conflict with just and reasonable rates.[70] It goes on to ask the OEB to "rethink its policies".[71] In support of this position, and as what it describes as relevant context, CCC includes a table from Alectra Utilities' MAADs proceeding setting out the then forecasted net synergies over the deferred rebasing period. CCC then argues that, because Alectra Utilities "from a management standpoint" has consolidated and is beginning the process of integrating its capital planning function, it should be precluded from incremental capital funding until it has filed a consolidated DSP.[72]

VECC, despite protestations to the contrary, also attacks the MAADs Handbook. As it says, "[W]e think the Board's amalgamation policies unfortunate."[73] Like CCC, VECC concludes by submitting that the OEB "should not approve any ICMs for Alectra Utilities before reviewing a comprehensive distribution system plan".[74]

AMPCO takes a similar approach. It begins by arguing that, "Alectra Utilities' ICM request coincides with significant merger savings", and also points to the forecast in the MAADs application. It too argues that the OEB should not approve the 2018 ICMs until Alectra Utilities has prepared a consolidated DSP.[75]

BOMA makes the same argument with respect to the need for a consolidated DSP – before any ICM funding, in any rate zone, may be approved.[76]

OEB staff make a somewhat different argument. They begin by observing, correctly, that the availability of the ICM was considered and resolved in the MAADs Decision. In fact, the availability of ICM was of such importance to the OEB that, in the MAADs Decision, it dedicated a section of the decision to re-articulating the MAADs policy as it specifically relates to the ICM. There, the OEB states that "[t]he 2015 Report extended the availability of the Incremental Capital Module (ICM), an

[70] CCC Submission, pp. 3-4.

[71] Ibid., p. 5.

[72] Ibid., p. 6.

[73] VECC Submission, para. 16.

[74] Ibid., para. 19.

[75] AMPCO Submission, pp. 2, 4.

[76] BOMA Submission, p. 40.

additional mechanism under the Price Cap IR rate-setting option to consolidating distributors on Annual IR Index, to allow adjustment to rates for any prudent discrete capital project that fits within an incremental capital budget envelope, not just expenditures that were unanticipated or unplanned. This provides consolidating distributors with the ability to finance capital investments during the deferred rebasing period without being required to rebase earlier than planned".[77]

Nevertheless, OEB staff goes on to say in its submission that, because Alectra Utilities intends to file annual ICM applications, the "IRM filing requirements would suggest that the Custom IR option would be the most appropriate option to deal with the circumstances outlined by Alectra Utilities in the current application".[78] The Applicant takes issue with this suggestion from OEB staff for three main reasons. First, OEB staff is wrong to infer that Alectra Utilities intends to make annual ICM applications during the rebasing deferral period. As indicated by the Applicant during the Technical Conference, it will assess annually whether or not an ICM application will be required.[79] Second, it is the Applicant's view that using the Custom IR option would entirely defeat the purpose of the incentives, provided by the OEB through its consolidation policies, for shareholders to pursue consolidations. Third, OEB staff's suggestion that Alectra Utilities use the Custom IR option instead of pursuing recovery of incremental capital costs through the ICM mechanism undermines the OEB's MAADs Decision as it implies that Alectra Utilities should submit such an application prior to the end of the rebasing deferral period that the OEB expressly approved.

While also arguing that a consolidated DSP is a prerequisite to ICM finding[80] and adding its own particular gloss on the "profits" it says are being earned during the deferred rebasing period, SEC puts the matter even more bluntly in its submission when it states as follows:

> **3.2.36** But the Applicant should not be able to have their cake and eat it too. The Board has a mechanism for utilities with long-term, recurring capital programs that cannot be accommodated under Price Cap IR. Horizon is on that rate plan, Custom IR.

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[77] MAADs Decision, p. 8.

[78] OEB Staff Submission, p. 23.

[79] Transcript, Technical Conference (Day 1), p. 19-21.

[80] SEC Submission, paras. 3.2.31, 3.6.1 (d).

Later, in discussing the ICM application for the Enersource RZ, SEC devotes a full page to essentially repeating this submission.[81]

The OEB developed the MAADs Handbook to provide guidance to applicants and stakeholders on applications to the OEB for approval of distributor and transmitter consolidations and "subsequent rate applications".[82] The OEB did so in the context of the Renewed Regulatory Framework ("RRF"). The policy articulates incentives for shareholders of distributors to pursue consolidations, ultimately in the interests of customers. Subject to the conditions of specific MAADs decisions and concluded merger transactions, shareholders should have the opportunity to avail themselves of those incentives. Contrary to the submissions of opposing parties, the OEB established its policy creating those incentives while remaining mindful of its fundamental obligation to set just and reasonable rates, as well as to ensure the outcome-based approach called for under the RRF.

As the MAADs Handbook begins:

> The Commission on the Reform of Ontario's Public Services, the Distribution Sector Review Panel and the Premiers Advisory Council on Government Assets all recommended a reduction in the number of local distribution companies in Ontario and have endorsed consolidation. According to these reports, consolidation can increase efficiency in the electricity distribution sector through the creation of economies of scale and/or contiguity. Consolidation permits a larger scale of operation with the result that customers can be served at a lower per customer cost. Consolidations that eliminate geographical boundaries between distribution areas result in a more efficient distribution system.[83]

The OEB recognized this interest in, and support for, consolidation. The OEB stated that, in discharging its statutory obligation to review and approve consolidation transactions where they are in the public interest, it was committed to reducing regulatory barriers to consolidation. The OEB concluded the introduction to the MAADs Handbook by advising that:

> Recent OEB policies and decisions on consolidation applications have already established a number of principles to create a more predictable regulatory environment for applicants. This Handbook will provide further clarity to applicants, investors, shareholders, and other stakeholders. The Handbook also discusses the rate-making

[81] See SEC Submission, paras 3.4.18 to 3.4.23.

[82] MAADs Handbook, p. 1.

[83] Ibid.

> policies associated with consolidations and sets out the timing of when such matters will be considered by the OEB.[84]

In the MAADs Handbook, the OEB set out its policy with respect to the availability of ICM funding to consolidating distributors during a deferred rebasing period.[85] That policy is clear: to encourage consolidation, the ICM is available to consolidating distributors that are on Price Cap IR to provide those distributors with the ability to finance capital investments during the deferral period.

As has been conceded, the availability of ICM was considered and resolved in the MAADs proceeding.[86] Intervenor arguments opposing the availability of ICM were rejected.[87] The OEB had before it the "context" that parties such as CCC again reply upon. The OEB held that its policy is to permit distributors to retain savings achieved as a result of the merger "to offset transaction costs" – not to fund incremental capital requirements during the deferral period.[88]

The OEB was also well aware of the possibility that Alectra Utilities may be required to file multiple ICM applications. As the OEB noted at p. 10 of the MAADs Decision, "the applicants expect to file an ICM in each year for each rate zone under Price Cap IR during the deferred debasing period." Whether this will, in fact, be required is an open issue. As set out above, the evidence here is that Alectra Utilities will evaluate the need for ICM annually and that it does not know whether, or if so to what extent, ICM applications will be filed going forward. But, in any event, the point is that even if multiple ICM applications are required, the OEB rendered the MAADs Decision in full recognition of this fact.

Likewise, the OEB was well aware that Alectra Utilities would not be in a position to file a consolidated DSP until 2019.[89] Indeed, echoing submissions it makes in this case, SEC had argued that the OEB should require Alectra Utilities to file a DSP for the combined entity no later than December 2017 as a condition of its license.[90] The OEB disagreed.[91] While noting that the MAADs

[84] Ibid., p. 2.
[85] Ibid., p. 17.
[86] EB-2016-0025/EB-2016-0360, Decision and Order, December 8, 2016, pp. 10-11 ("MAADs Decision").
[87] Ibid., p. 12.
[88] Ibid., p. 6.
[89] Ibid., pp. 10-11.
[90] EB-2016-0025, Final Argument of the School Energy Coalition, October 10, 2016, para. 4.2.3.
[91] MAADs Decision, p. 12.

Handbook encourages consolidating entities to operate as one as soon as possible – something Alectra Utilities is actively doing – it imposed no such requirement. Nor did it limit the availability of ICM funding to post-2019. It is simply wrong to say that a consolidated DSP is required before Alectra Utilities is eligible for ICM funding.

Response to ICM Specific Projects

The following are Alectra Utilities' responses to the submissions of OEB staff and other parties on specific projects proposed for ICM treatment within each of the Alectra Utilities rate zones. The proposed ICM projects reflect incremental capital requirements within the context of Alectra Utilities' financial capacity underpinned by its existing rates, and each project satisfies the eligibility criteria of materiality, need and prudence. Further to the above, that the proposed ICM projects all qualify for ICM treatment, Alectra Utilities submits the full amount proposed for ICM treatment for each proposed ICM project should be approved. For reference purposes, Table 1 below provides a summary of the proposed ICM projects by rate zone and project classification.

Table 1 – ICM Projects by Rate Zone

CATEGORY	PROJECT	2018 BUDGET
BRAMPTON RZ		
System Access	1. Pleasant TS True-Up	$6.8MM
POWERSTREAM RZ		
System Access	1. York Region Rapid Transit VIVA Bus Rapid Transit Y2 and H2 Projects	$11.24MM
System Renewal	2. Station Switchgear Replacement - 8th Line MS323	$1.39MM
	3. Rear Lot Supply Remediation - Royal Orchard - North	$1.68MM
	4. Cable Replacement – (M49) - Steeles Ave and Fairway Heights Drive	$1.84MM
	5. Cable Replacement – (V08) - Steeles Ave and New Westminster	$2.64MM
	6. Circuit Breaker Replacement – Richmond Hill TS#1	$1.19MM
System Service	7. Rebuild of 27.6kV Pole Line on Warden into 4 Circuits from 16th Ave to Major Mackenzie	$1.37MM
	8. Mill St. MS835 Transformer Upgrade – Tottenham	$1.3MM
	9. Double Circuit 27.6kV Pole Line on 19th Ave between Leslie and Bayview	$1.2MM
	10. Double Circuit Existing 23M21 from Bayfield & Livingstone to Little Lake MS306	$1.28MM
ENERSOURCE RZ		

System Access	1. QEW – Evans to Cawthra Roads Project	$1.29MM
System Renewal	2. Glen Erin & Montevideo Subdivision Rebuild	$1.96MM
	3. Glen Erin & Battleford Subdivision Rebuild	$2.06MM
	4. Credit Woodlands & Wiltshire Subdivision Rebuild	$1.55MM
	5. Tenth Line Main Feeder Subdivision Renewal	$1.14MM
	6. Folkway & Erin Mills Main Feeder Subdivision Rebuild	$1.03MM
	7. City Centre Drive Rebuild (Walmart Cables)	$1.55MM
	8. Lake/John Area Overhead Rebuild	$0.93MM
	9. Church St. Area Overhead Rebuild	$1.02MM
	10. Transformer Replacement Project	$8.45MM
System Service	11. York MS	$3.27MM

Materiality

As discussed in the Applicant's Argument-in-Chief, the OEB, in the ACM Report, explains that the materiality threshold is, in effect, a capital expenditure threshold which serves to demonstrate the level of capital expenditures that a distributor should be able to manage with its current rates.[92] The Report goes on to state that "a capital budget will be deemed to be material, and as such reflect eligible projects, if it exceeds the OEB-defined materiality threshold. Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount (as defined in this ACM Report) and must clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing".[93] The means for determining the OEB-defined materiality threshold was updated in the Supplemental Report and is set out in section 3.3.2.2 of the Filing Requirements; it is also reproduced in the pre-filed evidence.[94] Alectra Utilities has appropriately calculated the materiality thresholds, and the corresponding eligible incremental capital amounts (i.e. maximum amounts eligible for recovery through ICM), in accordance with the ACM Report, Supplemental Report, Filing Requirements and the *Report of the Board: Rate Making*

[92] ACM Report, pp. 16-17.

[93] ACM Report, p. 17.

[94] See Exhibit 2, Tab 2, Schedule 10, p. 7; Exhibit 2, Tab 3, Schedule 10, p. 17; Exhibit 2, Tab 4, Schedule 11, p. 29.

Associated with Distributor Consolidation[95] for each of the Brampton, PowerStream and Enersource RZs.[96]

In addition to the materiality thresholds used for determining the total eligible incremental capital amounts for each rate zone, the OEB requires distributors to meet project-specific materiality thresholds.[97] The project-specific materiality threshold, which has been defined by the OEB as 0.5% of distribution revenue requirement,[98] has been calculated for each of the Brampton, PowerStream and Enersource RZs and, in each rate zone, the individual eligible projects each exceed the identified project-specific materiality threshold.[99]

OEB staff agree that Alectra Utilities has correctly determined the materiality threshold for each RZ and each of the project-specific materiality thresholds, and acknowledge that each of the projects for which ICM recovery is sought exceed the applicable threshold.[100] Given that the last rebasing for the Enersource RZ was in 2013,[101] and that the 2016 Custom IR application for the PowerStream RZ resulted in a single forward test year cost of service decision,[102] the extent of Alectra Utilities' incremental capital needs should not be surprising.

Need

In the ACM Report, the OEB explains that need must be demonstrated by (a) passing the Means Test, (b) the amounts must be based on discrete projects, which should be directly related to the claimed driver, and (c) the amounts must be clearly outside of the base upon which the rates were derived.[103]

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[95] See p. 10.

[96] See Argument-in-Chief, p. 14.

[97] ACM Report, p. 17.

[98] See ACM Report, p. 17; See also OEB, Decision and Order in Enersource's 2016 ICM (EB-2015-0065) at section 3.2: "Each capital project approved for ICM funding must be material to the distributor. Project materiality is 0.5% of distribution revenue requirement for distributors with a revenue requirement greater than $10 million and less than or equal to $200 million."

[99] See Argument-in-Chief, p. 15.

[100] See OEB staff Submission, pp. 18-19.

[101] Decision and Order, EB-2012-0033, December 13, 2012.

[102] Decision and Rate Order, EB-2015-0003, September 27, 2016.

[103] ACM Report, p. 17.

Under the Means Test, if a distributor's regulated return (as most recently calculated in accordance with RRR 2.1.5.6) exceeds 300 basis points above the deemed return on equity ("ROE") embedded in the distributor's rates, then the funding for any incremental capital project will not be allowed.[104] Alectra Utilities has demonstrated that, based on the accounts of the predecessor utilities, it has satisfied the Means Test in respect of each rate zone.[105]

Within the Brampton, PowerStream and Enersource RZs, each eligible capital project is a discrete project that exceeds the corresponding project-specific materiality level. Each project is distinct and has been evaluated in the asset management and capital planning process as required in 2018.[106] Unlike recurring capital program work, where costing is typically done at a high level (such as by multiplying unit costs based on historical expenditures), for each of the eligible capital projects Alectra Utilities has performed detailed, project-specific estimates based on a specific scope of work and detailed design carried out for a particular location.[107] Moreover, the costs of the projects for which Alectra Utilities seeks recovery through the ICM are incremental to the Applicant's capital requirements that underpin its existing rates for each RZ. Intervenor submissions with respect to the need for specific projects that have been proposed for ICM recovery by Alectra Utilities are addressed below.

An often-repeated argument made by parties is that certain of the projects are not discrete because they contemplate work that is similar in nature to recurring annual capital work. It is unfortunate that the OEB has not clearly articulated how its requirement, that projects be "discrete" in order to meet the "need" criterion for ICM eligibility, should be applied. Intervenors would have the OEB understand this to mean that if work is of a similar nature to or somehow connected to recurring annual capital work, then it is not "discrete" and should thereby be ineligible for ICM treatment. In Alectra Utilities' view, for the reasons that follow this is not what the OEB intended and would be wrong.

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[104] ACM Report, p. 15.

[105] See Exhibit 2, Tab 2, Schedule 10, p. 9 (Brampton RZ); Exhibit 2, Tab 3, Schedule 10, p. 20 (PowerStream RZ); Exhibit 2, Tab 4, Schedule 11, p. 32 (Enersource RZ).

[106] See Exhibit 2, Tab 2, Schedule 10, p. 9 (Brampton RZ); Exhibit 2, Tab 3, Schedule 10, p. 21 (PowerStream RZ); Exhibit 2, Tab 4, Schedule 11, p. 32 (Enersource RZ).

[107] See Technical Conference Transcript, Day 1, pp. 141-142

First, given the well-defined range of assets they own, operate and maintain – poles, conductors, transformers, stations – it is unlikely that distributors will encounter work that by its nature that is different than all other work that it regularly performs in connection with its system. The nature of the work is not what needs to be discrete. Rather, the intention is that the project be clearly defined, relate to a specific location or specific assets on the distribution system, and have a specific scope and timeframe for execution. A project that has these characteristics should be considered "discrete".

Second, there is no requirement that projects be unique or relate to work that is different in kind from work that is carried out as part of ongoing base capital work programs.[108] These are simply not criteria for ICM eligibility. To repeat, the ICM is available for discretionary and non-discretionary projects, as well as for capital projects not included in a distributor's previously filed DSP. It is not limited in its availability to extraordinary or unanticipated investments and it may be applied to projects that may be considered to be routine or business as usual.[109]

Prudence

The ACM Report and the *Filing Requirements* specify that the amounts to be incurred must be prudent, which means that a distributor's decision to incur the amounts must represent the most cost-effective option (but not necessarily the least initial cost) for ratepayers.[110]

The Applicant's eligible capital projects are prudent because, in the case of the Brampton RZ, it is for a non-discretionary project and, for the PowerStream and Enersource RZs, the projects represent the most cost effective options for ratepayers. In each case, the projects are based on capital investment needs for the Brampton, PowerStream and Enersource RZs for 2018 that are not funded through existing distribution rates.

To demonstrate the prudence of each eligible capital project for which Alectra Utilities is seeking approval, the Applicant has provided a business case summary that identifies the name, driver, cost and expected in-service date for the project, describes the project and its drivers, and sets out the

[108] ACM Report, p. 15.
[109] Ibid., pp. 6-7.
[110] ACM Report, p. 17; Filing Requirements, section 3.3.2.

various options considered for the project.[111] In addition, the Applicant has provided detailed business cases for each eligible capital project. The detailed business cases include relevant background information including with respect to the location and history of the project, detailed description of the scope of the project, as well as explanation as to the options considered and the budget and in-service dates for the work.[112] Where an option was considered and was determined to be feasible because it provided an alternative means of addressing the identified project needs, the Applicant has provided costing information for that option to assist in demonstrating that the recommended approach to implementing the project is the most effective option for its ratepayers. Intervenor submissions with respect to the prudence of specific projects proposed for ICM recovery by the Applicant are addressed below.

2.1 Brampton Rate Zone

2.1.1 Pleasant TS True-Up (System Access, $6.8MM)

This investment is required under the terms of the Connection and Cost Recovery Agreement ("CCRA") between Alectra Utilities and HONI for the construction of the Pleasant TS expansion in the Brampton RZ. The CCRA was entered into by the former Hydro One Brampton, in connection with its efforts to increase available transformation capacity for anticipated load growth in the northwest area of Brampton. The 10-year true-up payment under the CCRA is due in June 2018 and the Applicant estimates a shortfall of revenue to HONI relative to the forecasted demand used to calculate the capital contribution initially made. The Applicant therefore anticipates being required by HONI, under the terms of the CCRA, to provide a further contribution of $6.8MM in June 2018, with the specific amount and payment terms to be finalized at that time.

OEB staff and the PWU support approval for recovery of the full amount proposed.[113] All other parties oppose recovery.[114]

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[111] See Exhibit 2, Tab 2, Schedule 10, pp. 10-11 (Brampton RZ); Exhibit 2, Tab 3, Schedule 10, pp. 22-33 (PowerStream RZ); Exhibit 2, Tab 4, Schedule 11, pp. 33-46 (Enersource RZ).

[112] See Attachment 21 (Brampton RZ), Attachment 33 (PowerStream RZ), and Attachment 47 (Enersource RZ).

[113] OEB Staff Submission, p. 27; PWU Submission, para. 12.

[114] SEC Submission, pp. 21-26; CCC Submission, pp. 11-12; AMPCO Submission, p. 6; BOMA Submission, pp. 66-69.

The parties that oppose this investment raise four main arguments. First, they argue that because the original load forecast, with hindsight, turned out to be wrong, the prudence of the underlying facility (Pleasant TS) is called into question. Second, they argue that the CCRA governing the true-up payment between Hydro One Brampton and HONI was not an arms-length transaction and, therefore, should be subject to a higher level of scrutiny. Third, they argue that Hydro One Brampton's liability for the true-up was not disclosed in the merger proceeding and should have been addressed at that time. Fourth, they argue that the cost of the 10-year true-up payment under the CCRA was not included in the DSP and is not incremental to historical spending levels. Each of these arguments is discussed below. None has any merit.

The attack on the decision to build Pleasant TS is fundamentally misplaced. At issue here is not Pleasant TS but the forecast used in determining the amount of the capital contribution required under the 10-year true-up under the CCRA. As OEB staff observes, no parties objected to the forecast that was specifically used for determining the 10-year contribution.[115] The current forecast is reasonable as it is based on historic experience and therefore the amount of the CCRA 10-year true-up contribution is prudent. OEB staff supports this view.[116]

In any event, the forecast of growth was reasonable at the time the CCRA was executed in 2006.[117] The forecast was developed based on then actual recent growth and known development plans for the area.[118] Between 2001 and 2005, approximately 31,350 customers were connected in the Brampton RZ, which represented an annual average customer growth rate of 6.5%. For the five year period between 2002 and 2006, the Brampton RZ experienced an annual average summer peak growth of 4.8%. In 2005 and 2006, the Brampton RZ experienced 14% and 12% annual peak demand growth rates. Hydro One Brampton was required to run the existing Pleasant TS above the 10-day Limited Time Rating, and, thereby, beyond the normal capacity of the transformer station. Further, in July 2015, based on an operational decision by HONI, Hydro One Brampton had to shed customers by

[115] OEB Staff Submission, p. 25.

[116] Ibid.

[117] Undertaking JT.1.5

[118] Pre-filed evidence, Attachment 21.

means of a brown out. It was clear that a new station was required.[119] The station was built and placed into service in 2008.

Unfortunately, due to the economic downturn which could not reasonably have been foreseen, the growth anticipated in the 2006 forecast was significantly impacted. The general slowing of the economy reduced peak demand as well as customer additions. For example, while in 2004 Hydro One Brampton connected 7,233 customers, in 2009 it connected just 1,438 customers, an 80% reduction.[120] Although the economy and peak demand growth showed signs of recovery in 2012, peak demand at Pleasant TS decreased again from 2013 to 2016 due to natural conservation and energy efficiency. Notwithstanding this, the station was and continues to be necessary, and the expected demand growth and connections are materializing, albeit at slower pace than originally projected.

The suggestion that because Hydro One Brampton and HONI were affiliates raises concern with respect to the CCRA is equally misplaced.[121] The terms of the CCRA were dictated by the requirements of the Transmission System Code (the "Code") and HONI's connection procedures approved by the OEB thereunder.[122] In particular, section 6.5 of the Code establishes the requirements for transmitters to perform economic evaluations of new and modified connections. These requirements include obligations to implement an economic evaluation in accordance with the procedure and methodology prescribed under the Code.[123] That procedure provides, at section 6.5.3, that for new or modified connection facilities, a transmitter shall carry out a true-up calculation for low risk connections at the end of each of the 5th and 10th years of operation, as well as at the end of the 15th year of operation if actual load is 20% higher or lower than the initial load forecast at the end of the 10th year of operation.[124] In addition, section 6.5.6 provides that where a true-up calculation shows that a load customer's actual load and updated load forecast is lower than the load in the initial load forecast, and does not generate the initial forecast connection rate revenues, a transmitter shall require the load customer to make a payment to make up the shortfall.[125] These Code requirements

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[119] Ibid.; Technical Conference (Day 1), pp. 99-106.
[120] Undertaking JT1.5.
[121] SEC Submission, paras. 3.3.14-3.3.19.
[122] Pre-filed evidence, Attachment 20, p. 13.
[123] OEB, Transmission System Code, revised August 26, 2013, s. 6.5 ("TSC").
[124] Ibid., s. 6.5.3.
[125] Ibid., s. 6.5.6.

are the basis for the true-up payment that is now required. This was not a unique agreement. The CCRA is a standard form of agreement, used by HONI with all of its transmission-connecting customers, related or otherwise.

Moreover, the OEB has previously approved recovery of CCRA true-up amounts for other utilities and there is no basis for treating the CCRA true-up amount for Pleasant TS differently in this Application.[126] In fact, this was the second true-up under this particular CCRA and Hydro One Brampton was permitted to recover the costs it incurred in connection with the first true-up at the five-year point in the last rebasing application (EB-2014-0083).[127]

Regarding the contention that this payment should have been anticipated and addressed at the time of the merger, the Applicant notes that the potential liability for the 10-year true-up under the CCRA was not disclosed in the purchase agreement or the merger proceeding because the criteria for recognizing a liability were not met. In particular, under IAS 37, Alectra Utilities is required to recognize a liability when there is a present obligation, it is probable that there is an outflow of resources and a reliable estimate can be made. The 10-year true-up under the CCRA is scheduled for June 2018. As of 2016, there was no present obligation or ability to reliably estimate the liability and, as such, it was not addressed at the time of the merger. The Applicant is now able to reliably estimate the amount of the liability.

The 10-year true-up payment was also not included in the Brampton RZ DSP because Hydro One Brampton did not anticipate that the 10-year true-up would result in a need for a further contribution. It was expected that the 5-year true-up would be the last. Although section 6.5.3 of the Code contemplates true-ups at the end of the fifth and tenth years of operation for low risk connections, it was explained during the Technical Conference that, at the time of the 5-year true-up under the CCRA, the updated forecast showed that the 10-year true-up would not have resulted in a need for any further contributions. At that time, it was projected that the recession was over and that the anticipated growth rates would return. There was some growth trending back up in 2009-2012, but a

[126] See Decision and Rate Order (EB-2015-0065), April 7, 2016, p. 9.

[127] Hydro One Brampton, Application (EB-2014-0083), Exhibit 2, Tab 6, Distribution System Plan, p. 164 and Appendix A – Capital Project Business Cases, p. 19; OEB, Decision and Order (EB-2014-0083), Appendix A, December 18, 2014, p. 14.

subsequent drop in 2013 to 2014.[128] However, the economy did not recover and growth did not return as was anticipated in that updated forecast from five years ago. Consequently, a further contribution will be required at the 10-year true-up.

The Applicant also points out that SEC incorrectly states on p. 23 of it submission that the original cost of the Pleasant TS expansion project was $40MM when in fact the actual cost of the Pleasant TS expansion project was approximately $20.5MM.[129]

2.2 PowerStream Rate Zone

Alectra Utilities has ten proposed ICM projects in the PowerStream RZ, including one system access project of approximately $11.2MM, five system renewal projects totaling approximately $8.7MM and four system service projects totaling approximately $5.2MM, for an overall total of approximately $25.1MM.[130]

2.2.1 York Region Rapid Transit VIVA Bus Rapid Transit Y2 and H2 Projects (System Access, $11.24MM)

This project involves the relocation of overhead and underground distribution assets as required to accommodate York Region Rapid Transit Corporation's ("YRRTC") Bus Rapid Transit ("BRT") developments. The timing for this work is driven by the YRRTC in conjunction with its contractors. The project, which includes development of BRT rapidways, is a key component of York Region's Transportation Master Plan. Two sections along Yonge Street totaling 6.5 km (Y2) and two sections along Highway 7 and adjacent roadways totaling 8.5 km (H2) are scheduled for completion in 2018 and 2019. Each of Y2 and H2 involves major thoroughfares with significant overhead and underground distribution plant (including 27.6 kV feeders), which must be relocated before the rapidways can be built. Alectra Utilities is required to relocate its distribution plant to facilitate transportation infrastructure developments by applicable road authorities in accordance with the *Public Service Works on Highways Act*. Therefore, this project is considered mandatory.

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[128] See Transcript, Technical Conference (Day 1), pp. 93-96.

[129] Pre-filed evidence, Attachment 20, Revised Schedule "B".

[130] Exhibit 2, Tab 3, Schedule 10, p. 14.

SEC, VECC, CCC, AMPCO and BOMA oppose ICM treatment for this project.[131] OEB staff and PWU support approval for recovery of the full amount proposed.[132]

Parties that oppose approval of this project argue that it is similar to and should be treated in the same way as the Metrolinx rail electrification projects, namely by establishing a deferral account to record actual costs for future review and recovery. These parties argue that there is inherent uncertainty with government-backed infrastructure projects and that this is common to the Metrolinx and road authority projects, so the regulatory treatment should be consistent. Several parties also argue that this is recurring annual capital work and should therefore not be eligible for ICM.[133]

The PowerStream RZ DSP did not include the YRRT project and the funding in base rates for road widening does not include the YRRT related investments.[134] On May 22, 2015, PowerStream submitted its Custom IR application.[135] The projects included in the DSP corresponded to information from 2014, at which time YRRT had not yet identified these projects. Subsequent to filing that application, Alectra Utilities was informed of further enhancements to the transportation infrastructure and expansion of several Rapid Transit corridors.[136] These were brought to the attention of the OEB during the Custom IR proceeding and were noted in the OEB's decision, where it referenced PowerStream's contention that any reduction to its capital spending program was inappropriate, but that a reduction of $23.22MM was feasible, subject to PowerStream's potential need for an additional $20MM for the YRRT project.[137]

Though OEB staff supports approval of this project, it does raise a concern that Alectra Utilities is required to pay 100% of the cost of the relocations associated with this project pursuant to long-standing agreements with CN.[138] OEB staff suggested that the OEB should encourage Alectra

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[131] SEC Submission, para. 3.5.11; VECC Submission, para. 46; CCC Submission, p. 15; AMPCO, p. 21; BOMA Submission, pp. 38-39.

[132] OEB Staff Submission, pp. 28-29; PWU Submission, para. 12.

[133] SEC Submission, para. 3.5.11; VECC Submission, para. 46; CCC Submission, p. 15; AMPCO, p. 21; BOMA Submission, pp. 38-39.

[134] Response to Interrogatory PRZ-Staff-7, p. 2.

[135] EB-2015-0003.

[136] Ibid.

[137] EB-2015-0003, Decision and Order, August 4, 2016, p. 14.

[138] OEB Staff Submission, p.29.

Utilities to renegotiate the terms of those relocations. Alectra Utilities submits that OEB staff's concerns in this regard are misdirected. On the YRRT VIVA Bus Rapid Transit project, the Applicant does collect capital contributions.[139]

As described during the Technical Conference, there is a high level of certainty around this project based on specific information from YRRT. In particular, Alectra Utilities knows that the project will proceed and has signed purchase orders with various contractors, through YRRT, in the order of $10MM, for work to start in early 2018. Those contractors will complete various aspects of the work within specific time periods in accordance with YRRT's schedule.[140]

2.2.2 Projects Included in DSP with PowerStream's Custom IR Application

The PWU supports the requested funding for the following six projects. BOMA supports the requested funding for one of the following six projects (Mill St. MS835 Transformer Upgrade – Tottenham) and appears to take no position on two of the remaining six projects (Double Circuit 27.6kV Pole Line on 19th Ave between Leslie and Bayview and Double Circuit Existing 23M21 from Bayfield & Livingstone to Little Lake MS306). SEC, VECC, CCC, AMPCO and BOMA (except as noted), as well as OEB staff, oppose ICM treatment for the following six projects, which are described below:[141]

- Station Switchgear Replacement - 8th Line MS323 (System Renewal, $1.39MM)
- Circuit Breaker Replacement – Richmond Hill TS#1 (System Renewal, $1.19MM)
- Rebuild of 27.6kV Pole Line on Warden into 4 Circuits from 16th Ave to Major Mackenzie (System Service, $1.37MM)
- Mill St. MS835 Transformer Upgrade – Tottenham (System Service, $1.3MM)

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[139] Pre-filed evidence, Attachment 33, p. 10; Technical Conference, Transcript Day 2, pp. 1-3.

[140] Transcript, Technical Conference (Day 2), pp. 121-122.

[141] SEC Submission, para. 3.5.9; VECC Submission, para. 45; CCC Submission, p. 14; AMPCO Submission, p. 20; BOMA Submission, pp. 36-48; OEB Staff Submission, pp.32-33.

- Double Circuit 27.6kV Pole Line on 19th Ave between Leslie and Bayview (System Service, $1.2MM)
- Double Circuit Existing 23M21 from Bayfield & Livingstone to Little Lake MS306 (System Service, $1.28MM)

The Station Switchgear Replacement - 8th Line MS323 project involves replacement of low voltage switchgear at the 8th Line MS 323 station, which has been assessed as being in poor condition, at a high risk of failure and no longer supported by the manufacturer.[142] It also needs to be brought to current standards with respect to arc-resistant construction to reduce safety concerns.[143] The station serves approximately 2,700 customers and the project is expected to extend the useful life of the station as well as avoid 97,200 customer outage minutes per year, which would have otherwise affected 900 residential and commercial customers. In addition, since the replacement switchgear will not fit in the existing enclosure at the station, a new switchgear building will be required. A prefabricated switchgear building will be used to reduce outage time for construction.[144]

The Circuit Breaker Replacement – Richmond Hill TS#1 project involves replacing the 6 existing circuit breakers at Richmond Hill TS#1 due to technological incompatibility, a history of failures and the fact that manufacturer support is no longer being provided for this equipment. The project also includes procurement of one spare circuit breaker. The most recent failure involving this type of circuit breaker at this station affected 15,500 customers and took over two hours to fully restore service. A forensic analysis determined that the transient recovery voltage (“TRV”) rating of this type of breaker is inadequate for this station. The TRV rating is a critical parameter for fault interruption by a circuit breaker and the forensic analysis points to the fact that the inadequate TRV ratings will result in further and more costly unplanned breaker failures if not resolved in a planned manner. The project is expected to improve reliability, reduce the likelihood of customer interruptions and enable cost savings through the planned removal of obsolete equipment and standardization.

[142] PRZ-AMPCO-19.

[143] Pre-filed Evidence, Attachment 33, p. 11.

[144] Pre-filed Evidence, Attachment 33, pp. 11-15; Response to Interrogatory PRZ-AMPCO-19.

The Rebuild of 27.6 kV Pole Line on Warden into 4 Circuits from 16th Ave to Major Mackenzie project involves replacement of the existing two feeder 27.6 kV pole line on Warden Avenue with a four feeder pole line, extending existing feeders 12M10 and 12M11 into Markham North and increasing supply capacity by 40MVA with two new feeders. There are known large commercial facilities coming online in 2018 that will add 9.5MVA of new load, which will use up all available capacity on the two current feeders. Beyond 2018, projected growth associated with long-term area developments is expected to require 66 MVA of additional capacity, as a result of the North Markham Future Urban Area expansion, and further load growth due to the Highway 404 North Development. Without this investment, the existing feeders will be fully loaded in 2018 and Alectra Utilities will be very limited in its ability to restore power during feeder outages.

The Mill St. MS835 Transformer Upgrade – Tottenham project involves an upgrade of the Mill MS835 6MVA transformer in order to provide the necessary backup capacity to meet load growth anticipated by 2019. Three major residential developments, scheduled to be completed over the next four years in this area, are expected to add 1,300 new customers. This growth will result in an additional 2.7 MVA of peak load supplied by two stations by 2019, bringing the total loading of the two stations to 9.6MVA. This will exceed the emergency capacity of Mill MS835 (9.1 MVA) to provide backup in the event of failure at the Nolan MS834 station. Load is expected to continue to rise beyond 2019, reaching 12 MVA by 2025/26. This project is the most effective way to address the increased capacity requirements, as well as reliability, under single contingency scenarios.

The Double Circuit 27.6kV Pole Line on 19th Ave between Leslie and Bayview project involves construction of a double circuit pole line and extension of two 27.6kV circuits onto 19th Ave from Leslie St. to Bayview Ave. to meet significant growth in this area. It is anticipated that approximately 500 new homes will require connection to the distribution system in the area. Currently, there are no feeders on 19th Ave between Leslie and Bayview to support residential or commercial developments. Therefore, new load in the development area cannot be serviced unless feeders are installed to connect the new customers. A secondary driver stems from the radial configuration of the existing feeder on Leslie St, which means power is supplied from one end of the feeder only. There is no alternate supply from any other source in the event of an outage, thus giving rise to risks of prolonged outages. This issue will become more significant as the customer density in the area continues to increase.

This project provides available capacity sufficient to supply the immediate needs arising from the developments and provides the contingency offload for the radial feeder.

The Double Circuit Existing 23M21 from Bayfield & Livingstone to Little Lake MS306 project involves the extension of feeder 23M28 along the existing path of 23M21 from Bayfield St. and Livingstone St. to Cundles Rd. and Duckworth St., and transfers the supply of Little Lake MS306 from 23M21 to 23M28. This project will free up capacity on 23M21 to meet projected load growth, supply the new Livingstone MS310 and mitigate the existing thermal overloading issue under contingency conditions for the area. Transferring the supply of Little Lake MS306 to the 23M28 and supplying the new Livingstone MS310 from 23M21 will more evenly distribute load across both feeders. Contingency transfers from 23M21 will be accommodated by both the existing 23M6 and new feeder 23M28. The new circuit will require a rebuild of the existing pole line along Livingstone St (from Bayfield St. to Cundles Rd.) and along Cundles Rd. to Little Lake.

Variations of the above projects were included in the DSP that was filed as part of PowerStream's Custom IR application, with differences in timing and planned expenditures. OEB staff argues that the OEB already reviewed and made its decision on these projects in the Custom IR application and questions whether the ICM mechanism should be used to reconsider these expenditures.[145] In OEB staff's view, absent extraordinary circumstances, these expenditures do not meet the "need" criteria established in the ACM Report as these amounts are not clearly outside of the base upon which the rates were derived. OEB staff also argues that these projects are relatively small when compared to the forecast 2018 PowerStream RZ capital program of $110MM and that minor expenditures should be excluded from recovery through the ICM mechanism.[146] AMPCO and CCC argue that these projects are not discrete as they contemplate work that is similar in nature to recurring annual capital work and that it is not possible to determine if the recommended approaches are prudent because cost information on alternative options was not provided on some projects.[147]

With respect, OEB staff's argument is inconsistent with the MAADs Decision. As explained above, in the MAADs Decision the OEB confirmed that the ACM Report extended the availability of the

[145] OEB Staff Submission, p. 33.
[146] Ibid.
[147] CCC Submission, p. 14; AMPCO Submission, p. 20

ICM to prudent, discrete capital projects that fit within an incremental capital budget envelope, not just those that were unanticipated or unplanned.[148] The essential consideration is whether the amount requested is incremental to the distributor's capital requirements within the context of its financial capacities underpinned by existing rates.

In response to OEB staff's argument that these projects are relatively small and that minor expenditures should be excluded from recovery through the ICM mechanism, the Applicant notes that each of these projects is in excess of the applicable project-specific materiality threshold and that OEB staff has itself recognized this in its submissions.[149] OEB staff's submission on this point is inconsistent with the very notion of applying a materiality threshold.

As noted in the discussion of the "need" criterion above, projects do not need to be unique or related to work that is different in kind from that which is carried out through ongoing base capital work programs. Projects may be eligible for ICM whether discretionary or non-discretionary, whether in or not in a prior DSP, and whether routine or extraordinary.

In response to the contention that it is not possible to determine prudence in the absence of cost information on alternative options,[150] Alectra Utilities identifies that while it did provide cost estimates for alternative options for the majority of projects, where cost estimates were not provided for alternative options it is because the alternative options considered would not provide the required capabilities or meet applicable technical standards, as discussed in each of the relevant business cases.[151] For example, on the project at 8th Line MS323, the retrofit of existing switchgear was considered and determined not to be feasible as this would not address the arc-resistant capability required for safety purposes. As this option did not address the identified need, it was not priced. Other than a question from BOMA as to whether Alectra Utilities considered conservation or demand management ("CDM") as an alternative generally, parties did not ask any questions regarding the costing of alternative solutions. In response to BOMA-11, the Applicant clarified that CDM is not an alternative for system renewal investments (or CCRA true-up) and was instead accounted for in

[148] MAADs Decision, p. 6.
[149] OEB Staff, Submissions, p. 19.
[150] CCC Submission, p. 15.
[151] Pre-filed Evidence, Attachment 33.

system expansion projects. The absence of cost estimates for alternatives that do not meet the identified project need should not preclude the OEB from determining whether the recommended approach is prudent.

Alectra Utilities also notes that many of the arguments from intervenors are premised upon what appear to be a significant and widespread misunderstanding of the specifics of these projects and should therefore be given no weight. For instance:

- On the Planned Circuit Breaker Replacement – Richmond Hill TS#1 project,
    - AMPCO states that the business case included an option to replace the sub-standard type HKSA breaker with the type HD4 breaker but that a cost estimate for this option was not provided, which is necessary to assess whether the recommended approach is most cost-effective.[152] In fact, the "option" described by AMPCO is the recommended solution, so the budgeted amount of $1.19MM is the estimated cost of this investment;
    - SEC states that in 2018 Alectra Utilities plans to replace 10 switchgear/circuit breakers, four of which are in poor or very poor condition.[153] In fact, this project involves replacement of 6 circuit breakers due to technological incompatibility, which has been determined to be the cause of historical failures; and
    - BOMA argues that Alectra Utilities did not provide evidence to support that the proposed replacement type HD4 breakers are more electrically and mechanically robust.[154] In fact, the business case for this project clearly explains that the type HD4 breakers have been installed at other stations and have performed satisfactorily since 2009.

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[152] AMPCO Submissions, p. 23.
[153] SEC Submissions, p. 33-34.
[154] BOMA Submissions, p. 47.

- On the Mill St. MS835 Transformer Upgrade – Tottenham project,
  - AMPCO argues that this project is similar to the new station construction project at Little Lake MS in Barrie, which was undertaken in 2017.[155] In fact, the business case for this project clearly indicates that this project involves an upgrade of a transformer whereas the Little Lake MS project involved construction of a new station. This is a significant difference and is an unreasonable basis for AMPCO's argument that the project should not be approved because it is similar in nature to recurring annual capital work;
- On each of (i) the Rebuild of the 27.6 kV Pole Line on Warden from 16th Avenue to Major Mackenzie project, (ii) the Double Circuit 27.6 kV Pole Line on 19th Avenue from Leslie to Bayview project and (iii) the Double Circuit Existing 23M21 from Bayfield and Livingstone to Little Lake MS306 project, AMPCO argues that the projects are similar in nature to other pole line capital projects and are therefore ineligible for ICM funding. However, the business cases for each of the pole line projects proposed for ICM funding have distinct drivers and are designed to address specific and discrete system needs. Namely, the pole line project on Warden from 16th Avenue to Major Mackenzie is a rebuild project to add additional circuits, the project on 19th Avenue is to construct a new pole line to implement distribution feeders where none exist, and the expansion of the 23M21 feeder project from Bayfield and Livingstone to Little Lake MS306 is required to adequately supply the newly constructed station.

Moreover, despite generally taking the position that it does not support ICM funding for each of the Double Circuit Existing 23M21 from Bayfield and Livingstone to Little Lake MS306 project and the Double Circuit 27.6 kV Pole Line on 19th Avenue from Leslie to Bayview project, BOMA has not discussed or raised any concerns whatsoever in its submissions about these two projects. In the absence of submissions, the OEB should assume that BOMA takes no issue with the Applicant's requests in respect of these projects.

[155] AMPCO Submission, p. 24.

2.2.3 Rear Lot Supply Remediation - Royal Orchard – North (System Renewal, $1.68MM)

The rear lot distribution system in the area of Royal Orchard – North serves approximately 170 customers, is over 50 years old, has been assessed as being in very poor condition and is beyond the end of its useful life. Rear lot systems are more likely to be affected by major events such as storms and, due to accessibility problems, restoration is very difficult and costly. In addition, rear lot systems pose safety risks to workers, tree trimming is often required before crews can safely access equipment, and proximity to customer facilities inhibits access and introduces safety risks. There are operational inefficiencies when working on rear lot systems as well because most work must be performed without use of bucket trucks and modern hydraulic equipment, work requires access to multiple yards and tree trimming must be performed more frequently. This area will be converted to front lot underground supply over a three-year period from 2018 to 2020, which is the most effective option to eliminate the above-noted concerns and improve reliability. Approximately 110,000 outage minutes can be avoided per year (not considering major event days) as a result of this investment.

PWU supports approval for recovery of the full amount proposed. SEC, VECC, CCC, AMPCO and BOMA, as well as OEB staff, do not support ICM treatment for this project.[156]

OEB staff considers this project to be "new" in the sense that it was not included in the DSP filed with PowerStream's Custom IR.[157] AMPCO and CCC argue that this project is not discrete and involves work that is similar to ongoing annual capital work.[158] OEB staff argues that this project fails to meet the prudence criteria due to Alectra Utilities' failure to provide sufficient costing information to address the OEB's concerns from the PowerStream Custom IR decision and to demonstrate that the proposed expenditures represent the most cost-effective option for ratepayers.[159] AMPCO and CCC add that a determination regarding prudence cannot properly be made without cost information on the alternative options to the recommended project.[160] Finally, OEB staff and VECC argue that there were deficiencies in the customer engagement efforts relating to this project because

[156] SEC Submission, para. 3.5.9; VECC Submission, para. 45; CCC Submission, p. 14; AMPCO Submission, p. 20, 22; BOMA Submission, pp. 43-44; OEB Staff Submission, pp.29-31.

[157] OEB Staff Submission, p. 29.

[158] AMPCO Submission, p. 22; CCC Submission, p. 14.

[159] OEB Staff Submission, p. 31.

[160] AMPCO Submission, p. 22; CCC Submission, p. 15.

Alectra Utilities did not speak with the affected customers directly and did not indicate what feedback was received.[161]

Regarding OEB staff's statement that this project is "new", the Applicant notes that rear lot remediation investments were proposed in the PowerStream RZ DSP as a program based on average unit costs all bundled under a single budget. However, to address the OEB's concerns as expressed in its decision in the PowerStream Custom IR application (EB-2015-0003), and as explained in response to PRZ-Staff-10, PowerStream determined that it would approach this work differently, by restructuring or unbundling it into specific projects, each of which has a distinct and defined scope and schedule. This revised approach to the work previously contemplated in the PowerStream RZ DSP permits costing based on the project-specific design rather than based on average unit prices. The benefits of restructuring the program were discussed in 3-VECC-15 and 3-VECC-16, where the Applicant identified that 23% of the sites with rear lot supply could be addressed using alternative solutions.

As noted in the discussion of the "need" criterion above, projects do not need to be unique or related to work that is different in kind from that which is carried out through ongoing base capital work programs. Projects may be eligible for ICM whether discretionary or non-discretionary, whether in or not in a prior DSP, and whether routine or extraordinary.

In response to OEB staff's argument that Alectra Utilities failed to provide sufficient costing information to address the OEB's concerns from the PowerStream Custom IR decision or to demonstrate that the proposed expenditures represent the most cost-effective option for ratepayers, the Applicant identifies that the pricing for an overhead front lot (which was determined to not be a feasible alternative) was provided in response to BOMA-128(a). In the response to BOMA-128, the Applicant also references Undertaking TJC1.14 from the PowerStream Custom IR proceeding (EB-2015-0003) to explain why overhead front lot would not be feasible in this project area. Moreover, in response to PRZ-Staff-10, the Applicant clarified how PowerStream addressed the costing methodology concern previously raised by the OEB. It is important to clarify that Alectra Utilities is not seeking funding for the entire portfolio of rear lot remediation projects – only the Royal Orchard

[161] OEB Staff Submission, p. 30; VECC Submission, para. 43.

North section as described in the corresponding business case. In addition, at the outset of this section, the Applicant explained that costing for alternative options has only been provided for options that are feasible and which would meet the required project needs.

Alectra Utilities responds to the concerns raised in respect of the adequacy of its customer engagement efforts following the project-specific discussions, below.

2.2.4 Cable Replacement Projects

PWU supports approval for recovery of the full amount proposed for these projects. For the reasons that follow, SEC, VECC, CCC, AMPCO and BOMA, as well as OEB staff, do not support ICM treatment for the following two projects:[162]

- Cable Replacement – (M49) - Steeles Ave and Fairway Heights Drive (System Renewal, $1.84MM)
- Cable Replacement – (V08) - Steeles Ave and New Westminster (System Renewal, $2.64MM)

The Cable Replacement – (M49) - Steeles Ave and Fairway Heights Drive project involves replacing 3.7 km of substandard underground primary cables. Cable and splice failures are the leading cause of outage minutes, accounting for 19% of SAIDI in 2016. In this project area, the underground primary cable is 35 years old, has been assessed as being in poor condition and is at the end of its useful life. This project area is also one of the few remaining pockets of 13.8kV load supplied from John MS, via feeders John-F5 and John-F6. The performance of these feeders is many times worse relative to the SAIFI and SAIDI for the service territory. John-F5 is among the top 10 worst performing feeders out of the 322 feeders in the PowerStream RZ. Given the reliability concerns and higher losses associated with the 13.8kV system, the majority of 13.8kV load in this area has been converted to 27.6kV. Once all 13.8kV load is converted to 27.6kV, John MS can be decommissioned, thereby avoiding the costs of operating and maintaining an underutilized station. This project is expected to

[162] SEC Submission, para. 3.5.9; VECC Submission, para. 45; CCC Submission, p. 14; AMPCO Submission, p. 20, 23; BOMA Submission, pp. 44-46; OEB Staff Submission, pp.31-32.

result in 81,480 outage minutes avoided per year and lower transformer and distribution line power losses.

The Cable Replacement – (V08) - Steeles Ave and New Westminster project involves replacing approximately 16.2 km of substandard underground primary cables from 2018 to 2020. Cable and splice failures are the leading cause of outage minutes, accounting for 19% of SAIDI in 2016. In this project area, the underground primary cable supplies 1,090 customers, is approximately 40 years old, has been assessed as being in very poor condition and is at the end of its useful life. It has failed 9 times in the last four years, resulting in over 350,000 customer outage minutes. This project is expected to improve system reliability in the area, minimize the need for emergency reactive repairs and result in 109,998 outage minutes avoided per year.

OEB staff considers these projects to be "new" in the sense that they were not included in the DSP filed with PowerStream's Custom IR.[163] OEB staff references the OEB's decision on the Custom IR application where the OEB expressed concerns with cost increases associated with the underground cable replacement program and asked PowerStream to explain the reasons for the increase in unit costs over time at its next rate setting opportunity.[164] In PRZ-Staff-7, Alectra Utilities explained that following on the OEB's decision it reviewed its cable replacement program and determined that each cable replacement would thereafter be treated as a distinct project with a defined scope, schedule and cost to address a specific driver because doing so would bring greater rigour, discipline and accountability to project planning and implementation.[165] OEB staff argues that this response does not adequately address the concern expressed by the OEB in the Custom IR decision and that these projects do not satisfy the prudence criteria due to insufficient costing information to demonstrate that the proposed expenditures represent the most cost-effective option for ratepayers.[166] This latter concern is echoed by AMPCO and CCC.[167] In addition, OEB staff and VECC raise concerns about the adequacy of customer engagement with respect to these particular projects.[168]

[163] OEB Staff Submission, p. 29.
[164] Ibid., pp. 31-32.
[165] Response to Interrogatory PRZ-Staff-7.
[166] OEB Staff Submission, p. 32.
[167] AMPCO Submission, p. 23; CCC Submission, p. 15.
[168] OEB Staff Submission, p. 32; VECC Submission, para. 43.

Regarding staff's statement that this project is "new", the Applicant notes that in the PowerStream RZ DSP the cable replacement investments were proposed as a program based on average unit costs all bundled together under a single budget. However, to address the OEB's concerns from its decision in the previous PowerStream application (EB-2015-0003), PowerStream determined that it would approach this work differently, by restructuring or unbundling it into specific projects, each of which has a distinct and defined scope and schedule. This revised approach to the work previously contemplated in the PowerStream RZ DSP permits costing based on the project-specific design rather than based on average unit prices.

Regarding OEB staff's suggestion that the Applicant did not adequately address the concern expressed by the OEB in the Custom IR decision, Alectra Utilities notes that this was discussed in response to 3-VECC-16, where the Applicant explained that based on the restructured approach to these cable replacements it forecasted cost reductions of 28% for cable replacements and 11% for its left behind cable replacement initiative.

In response to the concern that there is insufficient costing information to demonstrate that the proposed expenditures represent the most cost-effective option, the Applicant notes that the main alternative that would normally be available to a cable replacement is cable injection.[169] However, injection is not always feasible. In the cable replacement project at Steeles Avenue and Fairway Heights, the existing cables are 8.32 kV and, as a result, injection would not align with plans to convert the area to 27.6 kV. If injected, the cables would soon need replacement and the costs of injection would become stranded.[170] Conversion to 27.6 kV brings numerous benefits, such as lower maintenance costs and reduced losses[171] (Business Case – Attachment 33, p. 33). In the cable replacement project at Steeles Avenue and New Westminster Drive, cable testing results indicated remediation by cable injection would not be feasible (Business Case – Attachment 33, p. 37). As indicated at the outset of this section, the Applicant has only provided costing for alternative options that are feasible and which meet the identified project needs.

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[169] Pre-filed Evidence, Attachment 33, pp. 31, 37.

[170] Ibid.

[171] Ibid., pp. 32, 37-38.

Alectra Utilities responds to the concerns raised in respect of the adequacy of its customer engagement efforts following the project-specific discussions, below.

2.3 Enersource Rate Zone

Alectra Utilities has proposed eleven ICM projects in the Enersource RZ. These include one system access project of approximately $1.3MM, nine system renewal projects totaling approximately $19.7MM and one system service projects totaling approximately $3.2MM, for an overall total of approximately $24.2MM.[172]

2.3.1 QEW – Evans to Cawthra Roads Project (System Access, $1.29MM)

This project is required by legislation to relocate electrical infrastructure to accommodate road work, as well as the final "cloverleaf" ramp configuration, arising from the MTO's redesign of the on and off ramps at Dixie Road and QEW. Timelines for the execution of the road works are driven by the Region of Peel, City of Mississauga, and the MTO. This mandatory project involves removal of 39 poles, relocation of 72 poles, installation of 3 temporary poles, as well as implementation of an underground crossing of the QEW. The MTO will contribute all costs related to the relocation of assets on municipal property, and share costs on a 50/50 basis for asset relocations on MTO lands.

OEB staff and the PWU support approval for recovery of the full amount proposed.[173] SEC, VECC, CCC, AMPCO and BOMA do not support ICM treatment for this project.[174]

The parties that oppose the project argue fundamentally, that it is comparable to other ongoing capital work programs.[175] In addition, AMPCO argues that, based on the inherent uncertainty in road widening projects and it's view that Alectra Utilities' 2018 capital plan reflects "aggressive" pole, transformer and cable replacement projects, that the latter should be deferred to accommodate the QEW – Evans to Cawthra Roads Project instead of approving incremental funding.[176] AMPCO also argues that this project is similar to the Creditview road widening project, which is in the base budget,

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[172] Exhibit 2, Tab 4, Schedule 11, p. 31.

[173] OEB Staff Submission, p. 21; PWU Submission, para. 12.

[174] SEC Submission, para. 3.5.9; VECC Submission, para. 49; CCC Submission, p. 13; AMPCO Submission, pp. 7-8; BOMA Submission, p. 9.

[175] Ibid.

[176] AMPCO Submission, p. 12.

and that the QEW – Evans to Cawthra project has a lower priority ranking than the Creditview project.[177]

AMPCO's proposal is illogical. The pole replacements they suggest should be deferred are needed to address the poor condition of those assets as identified by the Kinectrics ACA. The pole replacements proposed in this project are driven by the Applicant's obligation to accommodate the MTO's road project. To suggest that this work is somehow interchangeable is wrong. Moreover, the suggestion that the Applicant's capital plan is "aggressive" is not supported by the evidence. As explained in the Enersource RZ DSP at Table 12, the Applicant only plans on replacing 375 poles due to their condition as part of system renewal efforts, which is lower than the levelized recommendation of 494 poles that Kinectrics identifies. The evidence is clear that Alectra Utilities did not adopt Kinectrics' recommendations for pole replacements, as discussed at p. 92 of the Enersource RZ DSP.

As noted in the discussion of the "need" criterion above, projects do not need to be unique or related to work that is different in kind from that which is carried out through ongoing base capital work programs. Projects may be eligible for ICM whether discretionary or non-discretionary, whether in or not in a prior DSP, and whether routine or extraordinary.

In response to AMPCO, both the QEW – Evans to Cawthra project and the Creditview project are system access investments contemplated by the DSP for the Enersource RZ.[178] As indicated in response to BOMA IR 112, the QEW project is ranked 7th and the Creditview project is ranked 8th.[179]

2.3.2 Underground Cable Replacement Projects

PWU supports funding of all of these projects through the ICM. BOMA supports funding the City Centre Drive Rebuild – Walmart Cables project through ICM. SEC, VECC, CCC, AMPCO and

[177] Ibid., pp. 11-12.
[178] Pre-filed Evidence, Attachment 50, p. 523 ("Enersource RZ DSP").
[179] Response to Interrogatory BOMA-112.

BOMA (except as noted), as well as OEB staff, do not support ICM treatment for the following six projects, which are described below:[180]

- Glen Erin & Montevideo Subdivision Rebuild (System Renewal, $1.96MM)
- Glen Erin & Battleford Subdivision Rebuild (System Renewal, $2.06MM)
- Credit Woodlands & Wiltshire Subdivision Rebuild (System Renewal, $1.55MM)
- Tenth Line Main Feeder Subdivision Renewal (System Renewal, $1.14MM)
- Folkway & Erin Mills Main Feeder Subdivision Rebuild (System Renewal, $1.03MM)
- City Centre Drive Rebuild – Walmart Cables (System Renewal, $1.55MM)

The Glen Erin & Montevideo Subdivision Rebuild project involves renewal and replacement of early generation underground distribution cables and 8 padmount transformers in the project area. Increasing failures on early generation underground cables (which are mostly unjacketed, i.e. without a protective sheath, and/or direct buried) are leading to rising numbers of outages and having an adverse impact on reliability. Since 2013, SAIDI and SAIFI in the project area have been 4 times and 2 times greater than the three year system average, respectively. Customers in this area have experienced 2 outages every year for the last three years due to these specific assets alone. The cables and transformers in the area are approximately 40 years old and are beyond the end of their useful life. This project is the preferred solution as it provides an opportunity to remove redundant cables that were originally installed to accommodate the build phases of the subdivision. The new cables will be installed in PVC ducts to make future replacement much less costly and will meet current standards for residential underground distribution.

The Glen Erin & Battleford Subdivision Rebuild project involves renewing and replacing early generation underground distribution cables and 5 padmount transformers in the project area to bring them in line with present day standards. Increasing failures on early generation underground cables (which are mostly unjacketed and/or direct buried) are leading to increasing outages and adversely

[180] SEC Submission, para. 3.4.23; VECC Submission, para. 49; CCC Submission, pp. 12-13; AMPCO Submission, pp. 7-8; BOMA Submission, pp. 16-18; OEB Staff Submission, pp. 37-38.

impacting reliability. Since 2005, 17 underground cable failures have occurred in this area, affecting 32,572 customers for a total of 191,139 outage minutes. The cables and transformers in the area are approximately 40 years old and are beyond the end of their useful life. The 2016 ACA flagged these cables as being in very poor condition and in need of immediate replacement. This project is the preferred solution as it provides an opportunity to remove redundant cables that were originally installed to accommodate the build phases of the subdivision.

The Credit Woodlands & Wiltshire Subdivision Rebuild project involves replacing cables that are beyond the end of their useful life and transformers (11 in total) showing signs of leaks or containing PCBs. The replacement of transformers is needed to address safety, environmental, reliability, financial and regulatory risks and the replacement of cables is needed to address reliability issues. The cables and transformers in the area are approximately 37 years old. The 2016 ACA flagged these assets as being in very poor condition and requiring immediate replacement. This project provides an opportunity to remove redundant cables that were originally installed to accommodate the build phases of the subdivision. The new cables will be installed in PVC ducts, making future replacements easier and less costly.

The Tenth Line Main Feeder Subdivision Renewal project involves renewing and replacing the early generation underground feeder cables in the Tenth Line area. The 2016 ACA found the main feeder cables in this area to be in very poor condition and in need of immediate replacement. Two particular sections of direct buried cables have each failed 4 times, impacting a total of 7,074 customers and 3,684 customers, respectively. In addition, portions of this cable are located in rear lots, making repairs particularly difficult and resulting in significant disruptions to residents. This project provides an opportunity to remove redundant cables that were originally installed to accommodate the build phases of the subdivision. The new cables will be installed in PVC ducts, making future replacements easier and less costly.

The Folkway & Erin Mills Main Feeder Subdivision Rebuild project involves renewing and replacing early generation underground feeder cables in the Folkway and Erin Mills area. The 2016 ACA found the main feeder cables in this area to be in very poor condition and in need of immediate replacement. One particular section of direct buried cable has failed 5 times, impacting a total of 6,220 customers. Portions of this cable are located in rear lots, making repairs particularly difficult and resulting in significant disruptions to residents. This project provides an opportunity to remove redundant cables that were originally installed to accommodate the build phases of the subdivision. The new cables will be installed in PVC ducts, making future replacements easier and less costly.

The City Centre Drive Rebuild – Walmart Cables project involves replacing existing cables and civil infrastructure in this area to mitigate the risk of a significant and prolonged outage as well as to eliminate the safety hazards to field crews that arise from the current design of civil chambers. There are two subgrade utility chambers in this area that were constructed in the 1970s. Chamber configuration and condition present significant constraints in terms of physical access. When responding to cable outages in the area, workers have to operate in substandard and hazardous conditions resulting in prolonged complicated repairs and safety and operational risks. Based on the condition of the cables, failure is highly probable in the near future and this would result in a significant and prolonged outage to a large customer that is supplied by these cables.

Parties that oppose these projects argue that these projects are not unique relative to other underground cable replacement projects, that they involve normal capital expenditures and these projects, they say, are comparable to or part of routine ongoing work programs.[181] OEB staff further argues that the prudence and need criteria have not been met because Alectra Utilities has not shown an urgent driving need for these projects and there is evidence that one of the important historical causes for underground cable failures has now been effectively mitigated.[182] In a related argument, AMPCO suggests that these projects should not be approved because, in the Enersource RZ, the health index for underground cable in is improving over time and the long-term rate of underground cable failures is stable.[183]

As described in the pre-filed evidence, the Applicant implemented an overlay methodology to identify specific areas of its system that are the worst performing and most problematic in terms of underground cable failures.[184] Distinct projects were identified and developed to address those particular locations. Through its development of these projects, the Applicant is able to address

[181] Ibid.,

[182] OEB Staff Submission, pp. 38-39.

[183] AMPCO Submission, pp. 13-14.

[184] Exhibit 2, Tab 4, Schedule 11, pp. 9-12.

multiple system renewal needs in a more efficient and effective manner as compared to taking a programmatic approach to cable replacements or transformer replacements. A project by project approach also enables Alectra Utilities to right-size its distribution system through renewal, which would not be possible if it simply carried out a program of like-for-like cable replacements. Moreover, by applying a uniform project methodology to different project locations, Alectra Utilities is able to address the unique needs and circumstances of each project area through a clearly defined scope, budget and schedule specific to each project.

In response to OEB staff's argument, the evidence establishes that these projects are targeted at areas within the Enersource RZ with the highest levels of cable failures, well above what could be considered acceptable.[185] As summarized above, customers in these areas are exposed to a high number of outages resulting from failures of localized cable assets.[186] For example, in the Glen Erin and Montevideo area, customers experienced two cable failures each year from 2013-2015 and, in 2016, experienced twice that number.[187] From the perspective of customers in these areas, the need for these projects is pressing and significant. Moreover, the Applicant takes issue with OEB staff's suggestion that need for these projects may be called into question because the issue of heat shrink splices has been mitigated. Although it is correct that heat shrink splices were historically a significant issue for underground systems, these projects are designed to address increasing underground cable failures in the worst performing areas of the Enersource RZ, which is unrelated to the historical problem of heat shrink splices.

AMPCO's suggestion that the long-term rate of underground cable failures is stable, and that as a result these investments should not receive ICM funding, is simply wrong. AMPCO misreads JT2.20, which provides the August 2017 year-to-date number of cable failures, being 131.[188] This was further explained in response to ERZ-Staff-73, which clearly reflects the year-to-date number of cable failures as of August 2017 exceeded both 2015 and 2014 cable failures for the same period.[189] Indeed, in 2016 and 2017 Alectra Utilities experienced the highest number of cable failures it had over the

[185] Pre-Filed Evidence, Attachment 47, pp. 8, 14, 33; Undertaking JT 1.4; Response to Interrogatory ERZ-Staff-73.
[186] Ibid.
[187] Pre-Filed Evidence, Attachment 47, p. 8.
[188] Undertaking JT 2.20.
[189] Response to Interrogatory ERZ-Staff-73.

past seven years. AMPCO's suggestion that the health index for underground cables is improving over time is also wrong and misleading. The perceived trend that AMPCO highlights is not indicative of improved health of this asset class but rather of a change in the health index methodology. As explained in response to JT2.21, in 2015 Kinectrics revised the condition parameter criteria methodology for calculating the health index for non-tree retardant direct buried cables. Specifically, the upper and lower values of useful lives for non-tree-retardant direct buried cables was increased from 20 to 25 years and from 35 to 40 years, respectively. The consequence of this change was that the average health index of the feeder and distribution cables improved in comparison to the 2014 health index based on the prior methodology. Moreover, even if the evidence showed stability in the long-term rate of underground cable failures, this would not be a sound basis for not proceeding with these investments and would be contrary to good utility asset management practices.

2.3.3 Overhead Rebuild Projects

PWU supports approval for recovery of the full amount proposed. SEC, VECC, CCC, AMPCO and BOMA, as well as OEB staff, do not support ICM treatment for the following two projects, which are described below:[190]

- Lake/John Area Overhead Rebuild (System Renewal, $0.93MM)
- Church St. Area Overhead Rebuild (System Renewal, $1.02MM)

The Lake/John Area Overhead Rebuild project involves renewing the overhead system in the area south of Lakeshore Road W. between John Rd and Mississauga Rd to mitigate the risks of pole fires due to porcelain insulators, worker and public safety concerns due to missing ground wiring and poles in poor conditions, as well as potential environmental contamination due to transformer oil leaks. This project involves replacement of 50 poles that are in poor condition (with average age exceeding 40 years), 22 poles with problematic types of porcelain insulators, and 2 transformers showing signs of leaks, as well as installation of copper clad ground wires to deter theft of ground wires and of fibreglass switch brackets to minimize outages caused by animal contacts. New primary and secondary conductors will also be installed.

[190] SEC Submission, para. 3.4.23; VECC Submission, para. 49; CCC Submission, pp. 12-13; AMPCO Submission, pp. 14-15; BOMA Submission, pp. 33-34; OEB Staff Submission, pp. 39-40.

The Church St. Area Overhead Rebuild project involves renewing the overhead system in the area east of Queen St. along Church St. to mitigate the risks of pole fires due to porcelain insulators, worker and public safety concerns due to missing ground wiring and poles in poor conditions, as well as potential environmental contamination due to transformer oil leaks. This project involves the replacement of 55 poles that are in poor condition (with an average age exceeding 40 years), 9 poles with problematic types of porcelain insulators, and 6 transformers that show signs of leaks. The project will also involve installation of copper clad alternative ground wires to deter theft, and the installation of fibreglass switch brackets to minimize outages caused by animal contacts. New primary and secondary conductors will also be installed.

Parties who oppose these projects argue that these projects are not unique relative to other overhead rebuild projects, that they involve normal capital expenditures and that they are part of routine ongoing work programs.[191] In addition, OEB staff argues that the prudence and need criteria have not been met because Alectra Utilities has not shown an urgent need driving these expenditures and has not shown why this work cannot be deferred or paced by replacing individual worst-condition structures in these areas under the ongoing base capital Overhead Distribution Renewal and Sustainment program.[192] BOMA argues that these projects involve the replacement of more assets than is necessary and that the replacement of defective or poor condition assets can be handled through the corresponding annual base capital programs.[193]

As noted in the discussion of the "need" criterion above, projects do not need to be unique or related to work that is different in kind from that which is carried out through ongoing base capital work programs. Projects may be eligible for ICM whether discretionary or non-discretionary, whether in or not in a prior DSP, and whether routine or extraordinary.

OEB staff's argument in relation to the prudence and need criteria is misplaced. The business cases for these projects include maps and other information, including lists of the system deficiencies such as copper theft, leaking transformers, sub-standard overhead configuration and insufficient mitigation of animal contact, all of which demonstrates that these assets are in poor condition. Moreover, the

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[191] Ibid.
[192] OEB Staff Submission, pp. 39-40.
[193] BOMA Submission, pp. 33-34.

business cases show that these assets have failed resistograph testing (which indicates internal deterioration of poles from rotting and cavities that may not be visible from outside) and that the risks of deferring these projects includes system reliability risks, environmental risks, as well as public and employee safety risks.[194] Moreover, the business cases explain that the option of only replacing the hazardous, worst-condition assets is not preferred because, although it carried lower near term costs, over the longer term that option would result in increased maintenance, inspection and longer term replacement costs.[195] As noted, the ACM Report and the Filing Requirements clarify that prudence does not necessarily require that a project be the least initial cost option.[196] This implies that a prudent distributor should also be mindful of the cost of a project over the life of the relevant assets.

In response to BOMA's contention that these projects involve the replacement of more assets than is necessary, the Applicant references p. 46 of the business case at Attachment 47, which indicates that all poles that are assessed to be in good condition will be maintained if possible.

2.3.4 Transformer Replacement Project (System Renewal, $8.45MM)

This is a mandatory project that involves replacement of 2,244 transformers that have been identified as showing signs of oils leaks or containing PCB in a planned and paced manner until 2021. It addresses safety, environmental, reliability, financial and regulatory risks (particularly to avoid disruptive and costly environmental clean-up and ensure regulatory compliance). While distribution transformers are normally operated on a run to failure basis, the need to minimize safety, environmental, reliability, financial and regulatory risks has led to the replacement of 2,052 transformers identified through rigorous inspections in 2013 to 2016. Transformer oil leaks at 103 sites led to $5.6MM in incurred costs for environmental remediation and $19.4MM in capital expenditures for transformer replacements from 2013 to 2016, which were not included in rates. Based on those inspections, as of January 1, 2017, a total of 2,244 in-service transformers need to be replaced. In connection with this project, Alectra Utilities has leveraged opportunities to perform replacements during planned underground or overhead system renewal projects in order to minimize the number of site visits and outages required. Leaking transformers replaced as part of system

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[194] Pre-filed Evidence, Attachment 47, pp. 45, 47, 52, 54.

[195] Ibid., pp. 49, 57.

[196] ACM Report, p. 17; Filing Requirements, section 3.3.2.

rebuild projects are not included in the backlog of leaking transformers to be replaced as part of this multi-year project.

While the PWU supports approval of the amount proposed, SEC, VECC, CCC, AMPCO and BOMA, as well as OEB staff, do not support ICM treatment for this project.[197]

Parties that oppose this project argue that this project is not unique, that it involves normal capital expenditures and that it is part of routine ongoing work programs.[198] In addition, OEB staff argues that the prudence and need criteria have not been met because Alectra Utilities has not prioritized replacements based on the manner in which it has categorized the leaking transformers (i.e. all amounts of observed leakage have the same high priority).[199] A related argument from AMPCO and SEC is that all of the major and moderately leaking units appear to have already been replaced, so the replacements in the test year are only of units with minor leaking.[200] SEC further argues that the replacements do not result in reliability or customer service benefits.[201] Finally, OEB staff comment that: Alectra Utilities' new transformer asset condition assessment methodology and its move away from the run-to-fail operational approach for overhead and pad-mounted distribution transformers have the effect of driving this $8.45MM ICM expenditure in 2018; similar spending is expected for this item in each of the forecast years from 2019 to 2022; and that this is in contrast to the preference explicitly expressed by customers for control of rates.[202]

As noted in the discussion of the "need" criterion above, projects do not need to be unique or related to work that is different in kind from that which is carried out through ongoing base capital work programs. Projects may be eligible for ICM whether discretionary or non-discretionary, whether in or not in a prior DSP, and whether routine or extraordinary.

Although OEB staff comment that flat expenditure trends are typical of multi-year programs rather than discrete projects, for this project the replacement of transformers is to address a backlog arising

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[197] PWU Submission, para. 12; SEC Submission, para. 3.4.23; VECC Submission, para. 49; CCC Submission, pp. 12-13; AMPCO Submission, pp. 16-19; BOMA Submission, pp. 20-26; OEB Staff Submission, p. 41.

[198] Ibid.

[199] OEB Staff Submission, p. 41.

[200] SEC Submission, para. 3.4.13(c); AMPCO Submission, p. 19.

[201] SEC Submission, para. 3.1.13 (g).

[202] OEB Staff Submission, p.40.

over a number of years and will therefore take a number of years to complete.[203] The flat expenditure trend is a consequence of the Applicant having appropriately paced the work on this project towards a decline and end in 2021.[204]

Regarding OEB staff's comments concerning the adoption of a new asset condition assessment methodology, Alectra Utilities continues to run its distribution transformers on a run-to-failure basis.[205] However, new information, obtained as a result of continuous improvements in the Applicant's inspection practices (which the OEB encourages), namely by opening the door when inspecting transformers, has led to identifying that a number of its transformers are leaking. Upon becoming aware that the transformers are leaking, to ensure compliance with applicable environmental legislation and regulations and to minimize the risk of environmental liability, Alectra Utilities must take action to address the problem. The only available solution to bring Alectra Utilities into compliance and minimize liability risk is to replace the leaking transformers. Transformers with minor leaks are still leaking and are expected to continue to leak, resulting in greater volumes of oil discharging into the environment, which carries with it a greater risk of civil and regulatory liability under applicable environmental laws. In turn, these risks could give rise to increased costs in future. These aspects, which point to the mandatory nature of this work, support both the need for the project and the prudence of undertaking it as proposed.[206]

The Applicant also notes that it would be a perverse outcome if, instead of commending the Applicant's continuous improvement of its inspection practices, the OEB were instead to penalize the Applicant for prudently addressing the circumstances identified through that improved practice. Alectra Utilities respectfully submits that the OEB should be concerned about putting a chilling effect on the efforts of utilities to continue pursuing operational improvements such as enhanced inspection practices for fear of identifying new work requirements, the costs of which are incremental to the base upon which their existing rates are set.

[203] Technical Conference, Day 1, pp. 5, 17-19.
[204] Ibid.
[205] Ibid., p. 87.
[206] Ibid., p. 12.

In response to the suggestion by AMPCO and SEC that the transformer replacements in the test year would only be of units with minor leaking, there are approximately 1750 transformers remaining in service that were identified as having minor leaking at some point between 2012 and 2016.[207] It has been the Applicant's experience that minor oil leaks typically deteriorate into moderate or major leaks over time and, by the time the last such leaking transformer is removed under the proposed project timeline, it will have been up to 9 years since the time the leak was identified and classified as minor. When oil leaks, it compromises the transformer insulation and leads to premature failure. When transformers fail, they often rupture the tank and spill the remaining oil. As such, minor leaks are precursors to larger leaks or spills. Moreover, a number of the transformers contain PCBs, the spill of which can trigger reporting requirements that may in turn lead to compliance issues. There are real and significant costs that can be incurred to clean up from a transformer oil spill, along with real liability risks. The pacing for the project recognizes and seeks to minimize these risks and is therefore appropriate.[208]

2.3.5 York MS (System Service, $3.27MM)

This project involves upgrading York MS to increase station capacity to meet the forecasted increase in demand and improve the reliability associated with station equipment and configuration. The project includes installation of low voltage switchgear, high voltage switchgear, and a 20MVA power transformer. This project is driven primarily by growth in demand in the Meadowvale Business Park Area. York MS supplies this area, which is the second largest employment area in Mississauga. The area is forecasted to experience an increase in load of 20MVA over the next 5 years due to planned business and employment growth. Based on the current distribution system configuration, approximately 50% (or 10MVA) of this forecasted load increase will need to be supplied from York MS, which has a normal operating capacity of 20MVA and present demand of 14MVA. As such, load on the station will in the near term exceed the station's normal operating capacity. A second driver for this project is the need to update equipment and the configuration at the station to bring these in line with current standards and improve reliability. Originally commissioned in 1998 as a

[207] Pre-filed Evidence, Attachment 47, p.60
[208] Ibid.

temporary station, the existing equipment and configuration is outdated and sub-standard, and experiences reliability issues associated with the cable egress, protection and station configuration.

While the PWU supports approval of the amount proposed, SEC, VECC, CCC, AMPCO and BOMA, as well as OEB staff, do not support ICM treatment for this project.[209]

With the exception of OEB staff, the intervenors who oppose this project argue that this project is not discrete, that it involves normal capital expenditures and that it is part of routine ongoing work programs.[210] Despite its view that this project is discrete, OEB staff argue that need and prudence have not been demonstrated because Alectra Utilities has not shown that this project was more critical than other projects in the substation upgrade base capital program or the Webb MS upgrade project, which was deferred for two years in response to the expressed customer preference for minimal rate increases.[211] Finally, on the assumption that this project would address assets that affect reliability for only 100 residential consumers, BOMA argues that this does not rise to the level of having a significant impact on the operation of the utility.[212]

As noted in the discussion of the "need" criterion above, projects do not need to be unique or related to work that is different in kind from that which is carried out through ongoing base capital work programs. Projects may be eligible for ICM whether discretionary or non-discretionary, whether in or not in a prior DSP, and whether routine or extraordinary.

In response to OEB staff's argument that need and prudence have not been demonstrated, the Applicant references the business case for this project, which demonstrates the basis for the Applicant's understanding of job growth projections from the City of Mississauga and explains that half of the 20 MVA of demand growth in the area has been allocated to York MS.[213] Moreover, as explained during the Technical Conference, the York MS was originally built as a temporary station.[214] It has poor reliability, does not provide Alectra Utilities with sufficient capacity to supply

[209] PWU Submission, para. 12; SEC Submission, para. 3.4.17; VECC Submission, para. 49; CCC Submission, pp. 15; AMPCO Submission, pp. 19; BOMA Submission, pp. 34-36; OEB Staff Submission, p. 41.

[210] Ibid.

[211] OEB Staff Submission, p. 41.

[212] BOMA Submission, p. 35.

[213] Pre-filed Evidence, Attachment 47, pp. 69-70.

[214] Technical Conference, Day 2, p. 175

the City's projected growth in the area of the Meadowvale Business Park, and needs to be upgraded to meet current standards.[215] The Webb MS project was deferred. The main driver for that project was growth in the downtown core. The Applicant determined that increased CDM was able to be applied so as to enable that deferral. However, it was determined that CDM efforts would not address the sub-standard assets at York MS so deferral was not a feasible alternative.[216] Whereas station renewals under the base capital program for 2018 address sub-standard and deteriorating assets, the York MS project is driven both by system renewal needs and area growth.

As noted, BOMA argues that this project does not rise to the level of having a significant impact on the operation of the utility. It makes this argument based on the incorrect assumption that this project would address assets that only affect reliability for 100 residential consumers.[217] In fact, as described in the business case for this project, the York MS serves the Meadowvale Business Park and not residential customers.[218] The business park has a combination of commercial and industrial customers who would be significantly impacted in the event of a failure at the York MS. In addition, new commercial and industrial customers, which are expected based on the City's job growth projections for the Meadowvale Business Park area, wanting to locate or expand operations in the business park cannot be connected without Alectra Utilities increasing the capacity of York MS.[219] Due to the long lead time for this project, it must be planned and built based on the Applicant's reasonable expectation that these needs will materialize within the expected time frame so as to have the necessary capacity available to meet customer needs.

Customer Engagement

The OEB's Rate Handbook advises that "customer engagement is expected to inform the development of utility plans, and utilities are expected to demonstrate in their proposals how customer expectations have been integrated into their plans, including the trade-offs between outcomes and costs".[220] To assist it in meeting this expectation, Alectra Utilities engaged IRG to undertake

[215] Pre-filed Evidence, Attachment 47, p. 70.

[216] IR-BOMA-54.

[217] BOMA Submission, p. 35.

[218] Pre-filed Evidence, Attachment 47, p. 70.

[219] Ibid.

[220] Rate Handbook, p.11.

customer engagement for the Enersource RZ DSP,[221] as well as for the Applicant's other rate zones. IRG prepared a Customer Engagement Report (the "Customer Engagement Report").[222]

The engagement process was designed to ensure three things:

1. Alectra Utilities received the input needed to make key decisions regarding the issues addressed by this Application.

2. Customers had the information they needed to provide meaningful responses to Alectra Utilities' questions.

3. Customers grounded their responses on their personal assessments of their needs and their preferences regarding a broad range of potential outcomes.[223]

Parties complain about Alectra Utilities' customer engagement efforts.[224] These complaints fall into two broad categories. First, a complaint about the process itself; and, second, criticism of the questions asked, or not asked, of customers.[225] Because parties generally did not differentiate in argument between customer engagement in relation to the Enersource RZ and DSP and the ICM request, Alectra Utilities responds here to all of their complaints.

1. Process Complaint

This is VECC's complaint. It claims that:

> Most of the surveying does not meet the scientific criteria of being random and with a sufficiently large sample size to be meaningful. Much of the customer engagement evidence, specifically, the online voluntary feedback suffers from self-selection bias is the problem that results when survey respondents are allowed to decide entirely for themselves whether or not they want to participate in a survey.[226]

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[221] Pre-file Evidence, Attachment 50, pp. iv, v.

[222] Pre-file Evidence, Attachment 51.

[223] Ibid., p. 2

[224] OEB Staff Submission, pp. 44-48; SEC Submission, paras. 1.2.6-1.2.11; CCC Submission, pp. 6-7; BOMA Submission, pp. 4, 6; VECC Submission, paras. 5, 42, 43.

[225] Ibid.

[226] VECC Submission, para. 5.

This argument fundamentally mischaracterizes the work done by IRG and the role of the qualitative element of this consultation. This role is summarized as follows:

> This comprehensive online customer engagement provided low-volume customers an opportunity to have their voices heard by Alectra Utilities. **The online feedback portal also helped identify a directional range of views that exist among customers. These ranges of views were then tested through representative customer telephone surveys in order to determine how many customers ultimately share identified points of view.** [Emphasis added.][227]

IRG did not rely exclusively on the workbook. Rather, it "tested" and confirmed the views expressed through statistically significant telephone surveys. This is the standard method used by IRG with which the OEB is intimately familiar.

2. Questionnaire Design and Question Wording

Parties' challenges to the specific questions asked or not during the IRG engagement process are discussed below.[228] At the outset, however, some context concerning customer engagement is required.

Every customer consultation has two key barriers: customers begin with limited knowledge of the utility; and they are not prepared to devote a lot of time to a consultation.[229]

These barriers have important implications:

1. To ensure the engagement includes a representative sample, all consultation tools must give low information participants the information they need to provide a meaningful answer to any question.

2. All consultation tools need to limit the time demands they place on participants or else risking bias by losing less engaged customers.

Any survey or workbook must begin with the assumption that respondent knows very little about the utility. In this case, due to the merger, the engagement had to start with the name. Question B5 of

[227] Customer Engagement Report, p. 10.

[228] OEB Staff Submission, pp. 44-48; SEC Submission, paras. 1.2.6-1.2.11; CCC Submission, pp. 6-7; BOMA Submission, pp. 4, 6; VECC Submission, paras. 5, 42, 43.

[229] Technical Conference, Day 1, p. 129.

the telephone surveys established awareness of the name and the introduction in B6 established the language to be used as the survey progressed.[230]

It is also important to ensure that customers understand what a distributor does and does not do, as well as what portion of their bill applies to the distributor. All customers must at least have that information at hand before more substantive questions can be addressed. This was addressed with questions, B7 and D15 in the telephone survey.[231] Only with those questions, could IRG be sure if the comments being collected were focused on Alectra Utilities and its responsibilities, or if they were focused on other elements of the electricity system.

Providing Context for Choices. Customers generally do not have pre-existing opinions readily available. The telephone surveys were designed to elicit the range of key considerations for customers. Questions B8 and B9 allowed IRG to collect information about customers' needs.[232] Questions C11, C12, C13 and C14 allowed customers to provide feedback on the goals Alectra Utilities should pursue in its business plan.[233] Both closed and open-ended questions were used. The closed-ended items were tested for completeness in the testing focus groups. The items used in the survey were the highest priority from those groups. Open-ended questions were provided as safety-valves for customers to express specific needs and to identify other priority outcomes.[234] This ensured that customers did not move into the more detailed questions until they had considered their own needs and the broad range of goals the utility should pursue.

Providing Tools for Analysis. The sample itself allowed customers to be grouped by region, rate class and usage within rate class. In addition, IRG included two "controls" for factors that are often found to influence opinions on distribution issues: economic vulnerability and confidence in the overall electricity sector.

BOMA misunderstands the use of controls. It says:

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[230] Customer Engagement Report, Appendix 6.7, p. 3.
[231] Ibid., p.5.
[232] See for example, Customer Engagement Report. Appendix 6.1, p. 3
[233] Ibid., 5
[234] Ibid., pp. 4-15.

> Innovative attempts to downplay the impact of the customers' strong statements of resistance to further rate hikes by introducing the idea that the resistance is only customers who are feeling the full impact of the rapid recent electricity price increases, which have suffered some financial hardship, that have reacted negatively.[235]

This statement is simply wrong. The OEB Handbook states that in reviewing customer engagement, the OEB will consider, among other things, "the quality of the utility's analysis of customer input."[236] It is therefore important for Alectra Utilities to understand customers' views about a specific set of proposed investments and where those views come from. When customer react, they may be reacting to specific elements of the proposed investments, however, their reaction may also be based on their broader views of the system or their personal economic circumstances.[237] This was confirmed, for example, in the PowerStream RZ.[238] There IRG found that the proportion of customers unwilling to accept any additional charges for increased capacity was almost twice as large among the economically vulnerable than among those that are not economically vulnerable.[239] Understanding whether opposition to specific proposals is based on that element or on the broader context is critical information in assessing how best to respond. As IRG concludes, it appears that much of the opposition in the PowerStream RZ was not based on the activity of enhancing system capacity but rather on economic circumstances.[240]

As an aside, BOMA also criticizes headlines in the IRG report.[241] This same criticism is repeated throughout its IRs. This is not a substantive complaint. In any event, as IRG advised in its IR responses:

> Regardless of the reader's interpretation of the data presented on any particular slide, the overall customer engagement research tells a clear and undeniable story of customer needs and preferences: The vast majority of Alectra Utilities customers are satisfied with their current level of reliability, and most support some form of

[235] BOMA Submission, p. 50.

[236] OEB Rate Handbook, p. 12.

[237] In another Ontario energy engagement, a consultation with intervenors identified vulnerable consumers as a critical audience to understand. See Energy Consumer Protection Act Review – IRG Consumer Consultation, May 2015, pp. 134.

[238] Customer Engagement Report, Appendix 2.0 PowerStream Ratepayer Telephone Survey, p. 22.

[239] Ibid.

[240] Ibid., p. 25.

[241] BOMA Submission, pp. 51-53, 55-60, 62-63.

> investment program (whether that be the proposed amount or a paced approach) that ensures a consistently reliable and modern distribution system.[242]

Focusing on the Key Topics. Any consultation should focus on eliciting information relevant to the matters at issue. Here, that meant relevant to the DSP and the ICM application.

IRG developed two sets of substantive questions: one set dealing with the Enersource RZ DSP and a second set addressing the ICM across both the PowerStream RZ and Enersource RZ customer samples.

The OEB Staff suggests that the information provided was limited.[243] This suggestion is misplaced. It fails to recognize the real, practical choices that have to be made between time and detail.

Many customers start with limited knowledge. The more "technical" an engagement becomes, the more participants that are lost. That means the sample becomes less representative as people with limited interest in technical information or limited ability to understand technical information drop out. In so far as the tools invest time and space providing the background information required for low information participants to provide meaningful feedback, that "education" effort crowds out other topics.

OEB staff also complain that the cost/reliability tradeoffs presented to customers were based on the projects not being undertaken during the entire five-year span under consideration, rather than being postponed for a shorter period of time."[244]

This complaint is similarly misplaced. By and large discussion of specific projects related to the ICM. These are projects that, as the evidences establishes, should be done now. That is why Alectra Utilities has applied for incremental funding. In this context, the question of deferral, for example, of three versus five years is not meaningful. On the other hand, pacing was considered in the context of the Enersource RZ DSP.[245]

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[242] Responses to Interrogatories BOMA-30, BOMA-33, BOMA-46, BOMA-51, BOMA-124.
[243] OEB Staff Submission, p. 45.
[244] OEB Staff Submission, p. 46.
[245] For example, see Customer Engagement Report, Appendix 1.0 Enersource Ratepayer Telephone Survey, p. 35.

To identified preferences IRG took a multi-question approach in the telephone survey.

To provide input on trade-offs in the four major spending envelopes of the DSP, the engagement tools use value trade-offs such as F25 in the Enersource RZ residential telephone survey where customers were asked to choose between two statements:

1. To help minimize immediate costs to customers, Enersource should defer investments in system capacity needs until there is noticeable deficiencies in reliability.

2. Enersource should proactively invest in system capacity infrastructure to ensure customers in high growth areas do not experience a decrease in reliability, even if this adds a small increase to customer bills.

While BOMA attempts to dismiss these questions as "bromides" its argument lacks substance.[246] Questions such as F23 and F25 above specifically balance cost and reliability measures. Would you pay a higher increase to maintain reliability, or do you want Alectra Utilities to minimize costs until there are declines in reliability? This is a trade-off between outcomes of affordability and reliability expressed in terms that allow someone with no pre-existing knowledge to provide an immediate and meaningful reaction.

After considering outcome trade-offs generally (e.g. C11 through 14) and specifically (e.g. F25), the survey then presented three potential scenarios of price increases versus reliability moving from the increase required to sustain reliability versus potential significant decline with a rate freeze.[247]

Several issues are raised with respect to those questions.

SEC complains that no option was provided for increased reliability.[248] But why would it have been? Research already suggested most customers did not want that option and the workbook testing, the

[246] BOMA Submission, p. 54.
[247] For example, see Customer Engagement Report, Appendix 1.0 Enersource Ratepayer Telephone Survey, p.29.
[248] SEC Submission, para. 3.2.40.

"safety valve" open-ended questions in the workbook and the results on the customer needs and reliability questions all confirmed that there was no need to offer an option to increase reliability.[249]

For their part, OEB staff express concern in relation to questions that used directional measures (F29) "decline" or "decline significantly" on the basis that customers may have different views of the meaning of those terms.[250] The approach taken, however, is consistent with other customer engagement efforts by IRG and common in any study of public spending priorities.[251]

As Mr. Lyle testified, people see the cost of electricity as an issue of "more or less".[252]

The Consumer Council of Canada (CCC) boldly asserts that:

> There is no evidence that customers understood what "incremental" capital spending involved.[253]

Again, this is wrong. There were two steps to ensure that customers understood the information presented to them.[254] First, IRG conducted three nights of focus groups to test the workbook with customers for comprehension, balance and completeness.[255] Second, IRG included a set of diagnostic questions at the end of the workbook. One question asked whether the portal provided too much, too little or the right amount information. Another question asked if any content was missing. A third question asked if there were any remaining questions you would like answered. [256]

Most customers indicated the balance of information worked for them. There was no confusion over the issue of incremental funding in the final testing groups and no indication of any problem in the open-ended responses to the diagnostic questions.[257]

Interpreting the Results Some parties complain about how to interpret the results specifically related to whether or not the public is willing to pay more. CCC says that "there is no evidence that customers

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[249] Technical Conference, Day 1, pp. 130-31.
[250] OEB Staff Submission, p. 46.
[251] Christopher Wlezien, "The Public as Thermostat: Dynamics of Preferences for Spending" (1995).
[252] Technical Conference, Day 1, pp. 127-28.
[253] CCC Submission, p. 7.
[254] Customer Engagement Report, pp. 4-5
[255] Ibid., pp. 5-6.
[256] Ibid., pp. 6-8.
[257] Customer Engagement Report, Appendix 4.0 - Alectra Utilities Online Feedback Portal Report, pp. 49-52.

asked Alectra to spend more."[258] To the same effect, SEC baldy asserts, "The Applicant claims that its customers think it should spend more money to maintain the current level of reliability. That is not what the customers said… No customer suggested that the Applicant should spend more."[259]

These assertions are contrary to the actual evidence. It is misleading to say customers want lower rates to the exclusion of all other outcomes. Customers were not asked once about the trade-offs between increased rates and capital improvements; they were asked multiple questions. Customers are conflicted on whether or not they are prepared to pay more for proposed investments. There is no doubt that customers are concerned about price. But, as set out in the IRG Report, they are prepared to spend more for particular benefits.

Looking at questions related to the Enersource RZ DSP, a few examples include:

- 57% of former Enersource RZ residential customers choose spending more to maintain reliability over deferring investments to lessen the impact of any bill increases.[260]
- 52% of former Enersource RZ small business customers say Enersource RZ should proactively invest in system capacity, even if this adds a small increase, rather than defer the expense to minimize immediate costs.[261]
- 68% of former Enersource RZ mid-sized enterprises say it is more important to invest in equipment and tools over making do with what the utility already has.[262]

When asked about the ICM investments, most customers are prepared to pay something more, but there is disagreement on how much more. For example:

- 61% of former Enersource RZ residential customers are prepared to pay at least 6 cents more a month on investments in substations.[263]

[258] CCC Submission, p. 7.
[259] SEC Submission, p. 5.
[260] Customer Engagement Report, Appendix 1.0 - Enersource Telephone Survey Report, p. 17.
[261] Ibid., p. 52.
[262] Ibid., p. 84.
[263] Ibid., p. 30.

- 56% of former Enersource RZ small businesses are prepared to pay at least 23 cents more a month to invest in underground cable and overhead lines.[264]
- 59% of former Enersource RZ mid-sized enterprises are prepared to pay at least $4.27 more a month to invest in underground cable and overhead lines.[265]
- 47% of former PowerStream RZ residential customers are prepared to pay at least 3 cents more a month to invest in increased capacity.[266]
- 63% of former PowerStream RZ small businesses are prepared to pay at least 13 cents more a month to invest in infrastructure replacement and renewal.[267]
- 60% of former PowerStream RZ mid-sized enterprises are prepared to pay at least $2.16 more a month to invest in infrastructure replacement and renewal.[268]

The reality is that customer views on the proposed investments are not all one way or the other. The challenge for Alectra Utilities and the OEB is to balance these conflicting views.

BOMA raised an issue regarding its difficulties (although not customers) in understanding the "skips" in the ICM element of the survey and how the results were reported.

> BOMA finds the "recoding exercise" unintelligible and urges the company to describe exactly what it has in the way of recoiling to reach the results in the Table on p31. What is clear is that virtually every recoding exercise results in the more positive responses increasing.[269]

As noted above, time is limited in any consultation. Initial testing of the workbook found customers were concerned at the length of the survey. In response to that feedback, IRG developed an alternative approach which tested well in later focus groups.

As set out in the Customer Engagement Report, all customers were given an overall introduction to the ICM section (e.g. G31 in the Enersource RZ residential survey) and were then asked their overall

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[264] Ibid., p. 66.
[265] Ibid., p. 99
[266] Customer Engagement Report, Appendix 2.0 – PowerStream Telephone Survey Report, p. 22.
[267] Ibid., p. 47.
[268] Ibid., p. 69.
[269] BOMA Submission, p. 53.

response to the cost of the ICM proposal (e.g. G32 in the Enersource RZ residential survey). Respondents were given the choice between four possible responses:[270]

- The proposed rate increases is reasonable so long as power reliability is maintained in Mississauga.
- I'd like to understand how this request for increased rates is going to be invested before I can accept it.
- I don't care how this request for increased rates is going to be invested, it's unreasonable and I oppose it.
- Regardless of how this request for increased rates is going to be invested, I simply can't afford to pay an extra $0.42 per month in 2018.

Any respondents who said they wanted to understand more (response 2) or who had only an attitudinal reservation to the ICM proposal automatically continued to the questions about specific projects.[271]

Respondents who answered *the proposed rate increase is reasonable so long as power reliability is maintained* (response 1) or who answered they simply cannot afford the increase were then given an option to learn more details about the projects or to skip to the next projects.[272] This opportunity to skip the details was very well received in testing, and 73% of those who either accepted the price increase or rejected it because they simply do not have the money for it chose to skip the detailed questions.[273]

While this made the survey more user friendly and increased the chance that all types of customers would complete the entire survey, it also meant that many of the people who were most willing to pay more were NOT asked the detailed ICM questions.

What that means, is that when looking at the results, the position of the 138 out of 504 respondents who said they accepted the proposed rate increase to pay for the whole program are not being

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[270] Customer Engagement Report, Appendix 6.1 Enersource Residential Ratepayer Survey, p. 11.
[271] ibid.
[272] Ibid.
[273] Customer Engagement Report, Appendix 1.0 Enersource Ratepayer Telephone Survey, p. 27.

counted.[274] Contrary to BOMA's argument, the real distortion would be to disregard the views of those 138 people.

It is also worth noting that a flow chart was provided showing in picture format what is described above in words in the presentation of each and every question that was included in this skip.[275]

Project Scope. OEB staff suggest even more extensive consultation should have been undertaken. In brief, they suggest the following:

- That the utility collect customer feedback on needs and preferences not only at an overall level but on a project by project basis.[276]

- That the utility not just collect customer feedback on needs and preferences at the start of the process, but in reaction to decisions made throughout the planning process.[277]

The suggestion of consulting on a project by project basis appears to be based on an earlier PowerStream Decision in EB-2015-0003**.** That case has no application here. It was a decision on how to implement a program to deal with rear lot remediation program in which the utility had three options for how to proceed, and had staff on the ground at each affected home on three separate occasions. As the OEB then held, if you are making a decision that will impact customers and you are literally right in their backyard, you should talk to them about the choices.[278]

Subsequently, in October 2016, the OEB issued the updated Rate Handbook. It makes no reference to project specific engagement of the kind suggested by staff.

OEB decisions have focused consistently on the need to bring customer input into the planning process as early as possible.[279] Given the current Application was submitted within months of the establishment of Alectra Utilities, IRG and Alectra Utilities made a conscious effort to generate and

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[274] Ibid., p. 26.

[275] See for example, Customer Engagement Report, Appendix 1.0 Enersource Ratepayer Telephone Survey, p. 28.

[276] OEB Staff Submission, p. 47.

[277] Ibid., p. 48.

[278] EB-2015-0003, Decision and Order, August 4, 2016, pp. 19-20.

[279] See for example, EB-2014-0116, Decision and Order, December 29, 2015, p. 7; EB-2015-0003, Decision and Order, August 4, 2016, p. 10.

present partial results as early as possible in the process and to monitor and update Alectra Utilities if there was a change in direction. As matters unfolded, the final results were generally consistent with the initial results.

Issue 2.5

Does the Distribution System Plan (DSP) filed for the Enersource rate zone provide sufficient information to support the proposed ICM for this rate zone?

As part of this Application, consistent with the *Filing Requirements*, and to support the request for incremental capital for the Enersource RZ, Alectra Utilities filed a DSP for the Enersource RZ for a five-year term from 2018 to 2022. The Enersource RZ DSP outlines Alectra Utilities' strategy of taking a complete lifecycle approach to the management of its Enersource RZ assets. The DSP includes sufficient information to support the proposed ICM for the Enersource RZ. Further, it provides justification for the Applicant's proposed expenditures in the Enersource RZ relating to the distribution system and general plant for the 2017 bridge year and the 2018 to 2022 period, including investment and asset-related maintenance expenditures.

The PWU agrees with Alectra Utilities that the Enersource RZ DSP provides sufficient information to allow for an assessment of the ICM expenditures proposed in the Application. In its submission, the PWU states that "Enersource's DSP provides sufficient information to demonstrate an appropriate balance of risk, performance, and cost. The Enersource rate zone's reliability metrics have been worsening since it last rebased in 2013. The DSP filed as part of this application informs appropriate investments to improve reliability while keeping bills manageable for its customers".[280] While noting that the OEB does not "approve" DSPs per se, OEB staff similarly agrees that the Enersource RZ DSP allows for an assessment of the ICM expenditures proposed in the Application.

OEB staff does complain that the DSP does not adequately explain why some planned capital expenditures are treated as base capital program expenditures while others are classified as ICM project expenditures. However, the *Filing Requirements* simply do not require this.

SEC argues that the OEB should accept the Enersource RZ DSP, but neither approve it nor reject it. SEC acknowledges that Alectra Utilities has complied with the requirement in EB-2015-0065 to file

280 PWU Submissions, p. 6.

a DSP but argues that the Enersource RZ DSP is an "outdated pre-merger document", has no value and is not helpful to the OEB. SEC also claims that the Vanry Report should not be relied upon by the OEB. SEC questions Vanry's expertise and independence, something it chose not do as part of the proceeding. VECC echoes SEC's submission that the Enersource RZ DSP is outdated and goes on to argue that there is no discussion in the Enersource RZ DSP as to the coordination of information technology or regarding changes to building requirements, rolling stock or any other aspects likely to change as rationalization occurs in the new company. AMPCO argues that there are flaws in the Enersource RZ DSP that decrease confidence in the forecast 2018 capital budget and that the increase in capital spending has not been adequately justified by the Enersource RZ DSP. AMPCO also argues that due to the timing of the Enersource RZ DSP, Alectra Utilities did not incorporate Vanry's recommendations in the Enersource RZ DSP. BOMA argues that the Enersource RZ DSP is not in accordance with the OEB's RRF policies, particularly because it does not reflect customer needs and preferences.

The assertion that the DSP is a pre-merger document is wrong. Parties that make this argument appear to equate the draft DSP filed by Enersource in EB-2015-0065 with the DSP filed as part of this Application. They are not the same. The Enersource RZ DSP is a standalone, new document. It forms the basis for the project-based funding relief sought for the Enersource RZ ICM by describing how the distribution system and associated infrastructure is planned, managed and developed, and how capital investments are determined so as to balance customer preferences and rate impacts with system requirements. In doing so, the Enersource RZ DSP leverages work that had been done previously and further reflects and incorporates customer feedback that has been more recently obtained.

With respect to Vanry, it provided its professional opinion that the Enersource RZ DSP and the underlying methodologies, analysis, and supporting documentation were in accordance with the OEB's Chapter 5 Filing Requirements.[281] Vanry found that the Enersource RZ DSP "represents a well-reasoned, fact based assessment of the needs of the system" and that "it reflects the desires of customers and the concerns of relevant stakeholders". It went on to conclude that "(t)he pacing of the investments appears reasonable and reflective of a need to balance between costs and performance

[281] Vanry Report, p. 33.

obligations and risks. The quality and caliber of the report, and the work that underpins it, is reflective of sound asset management processes and thinking".[282] To the extent SEC - alone among parties - now complains about Vanry, its late blooming attack should be rejected by the OEB. As set out in the Argument-in-Chief, questions could have been asked about Vanry or its report at the interrogatory or Technical Conference stages of the proceeding. SEC took neither opportunity. There is no basis for its argument. The OEB can and regularly does rely upon reports filed by parties in similar circumstances.

Parties concerns regarding the timing for the Enersource RZ DSP relative to the Vanry report and the Application misunderstand the process. During the course of Vanry's review, the Applicant incorporated feedback received from Vanry on an ongoing basis to the extent appropriate given circumstances in the Enersource RZ.

In response to VECC's assertion that there is no discussion in the Enersource RZ DSP as to the coordination of aspects that are likely to change as rationalization occurs in the new company, the Applicant notes that the Enersource RZ DSP was clear on this point. It explained that, as a result of the formation of Alectra Utilities in February 2017, certain General Plant investments planned by the former Enersource Hydro would instead be evaluated, prioritized and executed by Alectra Utilities as a consolidated entity to maximize efficiency gains and value creation and that, as a result, these investments were excluded from the Enersource RZ DSP. Instead, these General Plant investments will form part of Alectra Utilities' consolidated DSP for 2020-2024 that will cover all four rate zones.[283]

Regarding BOMA's assertion that the Enersource RZ DSP does not incorporate customer needs and preferences and is therefore contrary to the RRF, the Applicant notes that section 1.2.2.3 of the Enersource RZ DSP describes the Applicant's customer engagement efforts that informed the DSP, as well as the key findings therefrom. Alectra Utilities has taken these findings into consideration in developing, refining and finalizing the Enersource RZ DSP. For example, the Applicant determined that the Webb MS project would be deferred for two years, from an initial in-service date of 2018 to

[282] Vanry Report, p. 32.
[283] Attachment 50, Enersource RZ DSP, Executive Summary, p. vi.

2020.[284] As part of its customer engagement activities, Alectra Utilities heard that customers in the Enersource RZ want to maintain reliability, that they prefer investment in System Renewal over System Expansion and that they want more CDM programs. Based on this input, Alectra Utilities opted to defer construction of Webb MS by two years and increase its focus on CDM opportunities in the downtown core to minimize the impact of growth in the area and delay the need for the Webb MS project.[285] Vanry states in its report that the Enersource RZ DSP reflects the concerns of the stakeholders and the desires of customers.[286] Vanry concludes that it is evident that the customer engagement results have influenced the focus of the DSP as well as the associated investment planning.[287]

E. ACCOUNTING

Issue 3.1

Are Alectra Utilities' proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition, requests for new accounts and the continuation of existing accounts, appropriate?

Disposition of Group 1 Deferral and Variance Accounts ("DVA")

Alectra Utilities included in its Application a request for the disposition of Group 1 accounts over a one-year period including carrying charges projected to December 31, 2017, for the Horizon Utilities, Brampton, PowerStream and Enersource RZs. Alectra Utilities identified that the Group 1 balances, by RZ, exceed the disposition threshold of $0.001/kWh.[288]

Horizon Utilities RZ

Alectra Utilities asked for disposition of the Group 1 balance as of December 31, 2016 for the Horizon Utilities RZ in the amount of ($7,370,171).[289] OEB staff indicated that it has no concerns with the

[284] Enersource RZ DSP, section 3.1.6.

[285] Ibid.

[286] Vanry Report, p. 4.

[287] Ibid.

[288] Exhibit 2, Tab 1, Schedule 7, p.3, for Horizon Utilities RZ, Exhibit 2, Tab 2, Schedule 5, p.3, for Brampton RZ, Exhibit 2, Tab 3, Schedule 5, p.3, for PowerStream RZ, Exhibit 2, Tab 4, Schedule 5, p.3, for Enersource RZ.

[289] Undertaking JT Staff-3.

Applicant's request to dispose of its December 31, 2016 Group 1 DVA balances.[290] Alectra Utilities asks that the OEB approve the proposed disposition of its Group 1 DVA balances as requested.

Enersource RZ

Alectra Utilities asked for disposition of the Group 1 balance as of December 31, 2016 for the Enersource RZ in the amount of ($7,421,393).[291]

OEB staff indicated that Alectra Utilities identified an amount of $7,401,082 (credit) in its Argument-in-Chief compared to a disposition amount of $7,421,393 (credit) included in the continuity schedule in the IRM Model, filed as an attachment to JT Staff-2.[292] OEB staff asked Alectra Utilities to explain the difference and confirm the correct balance. No other parties made submissions on the Group 1 DVA balances for the Enersource RZ.[293]

In Alectra Utilities' Argument-in-Chief, Alectra Utilities identified an amount of ($7,401,082).[294] This represents the Group 1 balance to be disposed via rate rider. The amount to be disposed of via customer specific bill adjustments is ($20,311) (credits of $18,635 GA and $1,676 CBR).[295] The total amount requested for disposition is $(7,421,393). Alectra Utilities confirms that it seeks approval to dispose of a total Group 1 balance of ($7,421,393).

Brampton RZ

Alectra Utilities asked for disposition of the Group 1 balance as of December 31, 2016 for the Enersource RZ in the amount of ($5,732,154).[296] OEB Staff indicated that they have no concerns with respect to Alectra Utilities' proposals related to Group 1 DVA balances for the Brampton RZ.[297] No other parties made submissions on the Group 1 DVA balances for the Brampton RZ. Alectra Utilities

[290] OEB Staff Submission, p. 52.
[291] Undertaking JT Staff-2.
[292] OEB Staff Submission, pp. 55 and 56.
[293] Ibid.
[294] Argument-in-Chief, p. 32.
[295] Undertaking JT Staff-2, IRM Model, Tab 6A. GA Allocation_Class A, Tab 7A. CBR Allocation_Class A.
[296] Response to Interrogatory G-Staff-2.
[297] OEB Staff Submission, p. 56.

asks that the OEB approve the proposed disposition of its Group 1 DVA balances for the Brampton RZ.

PowerStream RZ

Alectra Utilities asked for disposition of the Group 1 balance as of December 31, 2016 for the PowerStream RZ in the amount of ($20,528,056).[298] In Alectra Utilities' Argument-in-Chief, Alectra Utilities identified an amount of ($20,550,622).[299] This represents the Group 1 balance to be disposed via rate rider. The amount to be disposed of via customer specific bill adjustments is a debit of $22,566.[300] The total amount requested for disposition is $(20,528,056).

OEB Staff indicated that the balance for disposition should be a credit of $22,168,522. The difference is due to an error in the amounts recorded under the "principal adjustments" and "interest adjustments" in 2016. OEB Staff submitted that the RPP settlement true-up adjustments were recorded as debits on the DVA continuity schedule, and they should have been recorded as credit amounts since the true-up settlement amount was a payment from the IESO.[301]

No other parties made submissions on the Group 1 DVA balances for the PowerStream RZ.

Alectra Utilities agrees with the Staff's submission. Alectra Utilities will update the IRM Model to record the RPP settlement true-up adjustment as credit amounts. The IRM Model for the PowerStream RZ will be updated appropriately in its Draft Rate Order, to be filed following receipt of the OEB's Decision on this Application.

Proposal to Change Previously Approved Rate Riders

Alectra Utilities proposed to update the 2016 GA rate riders with new 2016 GA rate riders for the period January 1, 2018 to September 30, 2018 in the PowerStream RZ.[302] As part of its approved 2016 rates, Alectra Utilities has GA rate riders for the PowerStream RZ, that expire September 30,

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[298] Undertaking JT Staff-5.
[299] Argument-in-Chief, p. 32.
[300] Undertaking JT Staff-5, IRM Model, Tab 7B. CBR Allocation_new Class B.
[301] OEB Staff Submission, p. 53.
[302] Exhibit 2, Tab 3, Schedule 5, p.6.

2018, that apply to all Class B non-RPP customers ("2016 GA rate riders"). The new 2016 GA rate riders are designed to recover the projected balance remaining at December 31, 2017 of $3,906,837, plus the over recovery from the Class B interval customers from the 2016 GA rate riders of $3,134,585, for a total of $7,041,422 to be recovered from the Class B non-RPP non-interval customers. Alectra Utilities proposes a rate rider to refund the amount over recovered of $3,134,585 to the Class B interval customers. The Class B interval customers were billed actual GA and should not be allocated any of the GA variance.[303]

OEB Staff submitted that although some intergenerational inequity may exist should the OEB approve PowerStream RZ's proposal, it would not have an impact on the total amount that the utility would recover and that this error could be corrected as part of the residual balance disposition given that the purpose of Account 1595 is to true-up approved balances. OEB staff indicated that Alectra Utilities is not making corrections to previously approved balances.[304]

In Alectra Utilities' submission the OEB should approve the proposal to update the 2016 GA rate riders in the PowerStream RZ to ensure that the GA balance that was previously approved for disposition, is allocated to the correct class of customers. Alectra Utilities proposes to recalculate the adjusted balances proposed for recovery and disposition based on the implementation date in the OEB's Decision in this Application.

Disposition of Capacity Based Response ("CBR") B Rate Rider to Five Decimal Places

Alectra Utilities requested disposition of the CBR B rate riders to the fifth decimal place for the Horizon Utilities, Brampton, and Enersource RZs.[305] Alectra Utilities proposed that this treatment aligns disposition of the CBR balances with the CBR bill adjustments for new Class A and new Class B customers and prevents intergenerational in equity. In response to interrogatory G-Staff-4, Alectra Utilities confirmed that the billing systems in the Horizon Utilities and Enersource RZs have the ability to bill to five decimal places, but Brampton's billing system is limited to four decimal places.[306]

[303] Ibid., p. 5.
[304] OEB Staff Submission, p. 55.
[305] Exhibit 2, Tab 1, Schedule 7, p.9, for Horizon Utilities RZ, Exhibit 2, Tab 4, Schedule 5, p.9, for Enersource RZ.
[306] Response to Interrogatory G-Staff-4.

OEB Staff indicated that it does not oppose the approval of rate riders for CBR Class B balances to five decimal places in order to minimize intergenerational inequity.[307]

Alectra Utilities asks that the OEB approve the proposed disposition of its CBR Class B balances to five decimal places for the Horizon Utilities and Enersource RZs. Alectra Utilities will seek disposition of the CBR Class B balance for the Brampton RZ in a future application.

Requests for New Accounts

Alectra Utilities has asked for approval for an accounting order to establish two new deferral accounts, for each of the PowerStream RZ and Enersource RZ, to record the financial impacts resulting from the Metrolinx Crossing Remediation Project.[308]

The Metrolinx Regional Express Rail ("RER") Electrification is an infrastructure roll out plan by Metrolinx that will entail the conversion of six of the eight GO rail corridors from diesel to electric propulsion in the Greater Toronto and Hamilton Area. As a result of the RER Electrification program, Alectra Utilities has determined that (i) all of the overhead crossings along the Lakeshore and Kitchener GO rail corridors for the Enersource RZ and (ii) all of the overhead crossings along the Barrie and Stouffville GO rail corridors for the PowerStream RZ are in conflict with the planned Overhead Catenary System for the GO electrification.[309]

For the Enersource RZ, a total of 28 crossings and 7 parallel lines along the Lakeshore and Kitchener corridors have been identified as being in conflict. For the PowerStream RZ, a total of 69 distribution system assets along the Barrie and Stouffville corridors have been identified as being in conflict.[310]

Due to restrictions on the height of the existing equipment and access limitations due to maintenance schedule windows, it was determined that the best option for mitigating the above-noted conflicts is to convert the crossings from overhead to underground.[311]

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[307] OEB Staff Submission, p. 56.
[308] Exhibit 2, Tab 3, Schedule 7; Exhibit 2, Tab 4, Schedule 7.
[309] Exhibit 2, Tab 3, Schedule 7, p. 2; Exhibit 2, Tab 4, Schedule 7, p.2.
[310] Ibid.
[311] Ibid.

The timeline for the Metrolinx tender is scheduled for 2019 for each of the rate zones and actual construction of the overhead catenary system is expected to start in 2020. Metrolinx has informed Alectra Utilities that several crossings will need to be remediated between 2017-2020 in the Enersource RZ and between 2017-2019 in the PowerStream RZ. Based on the proposed schedule, Alectra Utilities anticipates 10 crossings for Enersource RZ and 10 to 15 crossings for PowerStream RZ may need to be remediated in 2018 in order to align with Metrolinx's schedule for construction.[312]

As Metrolinx has not finalized the final design and identification of the specific number crossings to be remediated, it has not been possible to develop project costs. Alectra Utilities continues to monitor the progress and timelines of the project schedule as they are dependent on Metrolinx.

OEB staff opposes the request for two new deferral accounts relating to the Metrolinx Projects stating that the request was not consistent with the OEB's ICM policy.[313] CCC similarly argues that Alectra Utilities could apply for ICM treatment for these projects at a future date.[314] BOMA says that it is opposed to the deferral accounts request but indicates that once costs were incurred, Alectra Utilities could apply for a deferral account at that time[315].

VECC submitted that all of the transit related projects included in the ICM applications should be subject to deferral account treatment.[316] In VECC's view, this would include both Metrolinx projects in the PowerStream RZ and Enersource RZ, the YRRT in the PowerStream RZ and the QEW widening in the Enersource RZ[317].

In the Alectra Utilities' view, the Metrolinx projects are appropriate for deferral account treatment. They meet all of the OEB's criteria. For ease of reference those are repeated below:

- Causation – The forecasted expense must be clearly outside of the base upon which rates were derived;

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312 Ibid.
313 OEB Staff Submission, p.5.
314 CCC Submission, p. 15.
315 BOMA Submission, p.76.
316 VECC Submission, p.17.
317 Ibid.

- Materiality – The forecasted amounts must exceed the OEB-defined materiality threshold and have a significant influence on the operation of the distributor, otherwise they must be expensed in the normal course and addressed through organizational productivity improvements; and
- Prudence – The nature of the costs and forecasted quantum must be reasonably incurred although the final determination of prudence will be made at the time of disposition. In terms of the quantum, this means that an applicant must provide evidence demonstrating as to why the option selected represents a cost-effective option (not necessarily least initial cost) for ratepayers.

As identified in its evidence**,** the need for Alectra Utilities to move its distribution plant, as a consequence of the Provincial Government's extensive Metrolinx project, was unanticipated.[318] There is no question the level of expenditure will be significantly in excess of the OEB-approved threshold. Moreover, while the costs will be reasonably incurred, they will be subject to a prudence review at the time of the clearance of the accounts.

Notably, in EB-2014-0116 the OEB authorized Toronto Hydro Electric System Limited ("THESL") to establish an account similar to that which is being requested by Alectra Utilities in this Application. There, THESL requested a variance account to track the difference between the amounts included in in base distribution rates relating to third party initiated relocation and expansion capital spending and the amounts actually spent on such work as it occurs over THESL's Custom IR period. The focus for the account was the non-discretionary need for THESL to respond to requests from various third parties to relocate parts of its distribution system, which requests were described as volatile in terms of scope, cost and timing and outside of THESL's control.[319] The OEB approved the account as requested and, in so doing, recognized that these projects are outside of THESL's control and appropriate for a variance account.[320]

Included in the OEB's requirements regarding requests for new deferral accounts, applicants are required to provide a draft accounting order, which must include a description of the mechanics of

[318] Exhibit 2, Tab 3, Schedule 7, p. 3; Exhibit 2, Tab 4, Schedule 7, p. 2.
[319] THESL, Pre-filed Evidence (EB-2014-0116), Exhibit 9, Tab 1, Schedule 1, p. 26;
[320] OEB, Decision and Order (EB-2014-0116), December 29, 2015, p. 50.

the account, including providing examples of general ledger entries, and the manner in which the applicant proposes to dispose of the account at the appropriate time.[321] The draft accounting order is included in the application as Attachment 40, and was revised in response to interrogatory PRZ-Staff-27(c).

Alectra Utilities further submits that the OEB consider addressing the GO Transit electrification project on a generic basis as it is an issue that will affect the entire sector. As described in the recently issued *Final Utilities Impact Assessment Report for the GO Rail Network Electrification Transit Project Assessment Process*, the GO Transit electrification project will affect approximately one dozen OEB-regulated utilities across four regional municipalities, one county, five cities and five towns.[322] While Alectra Utilities may be the first to seek a deferral account for the unknown but considerable costs to move the distribution plant from the transportation corridors, based on contractual agreements that specify that the cost be borne by the utility entirely,[323] it is Alectra Utilities' submission that based on the extensive impact of this project other applications will be filed.

In the result, Alectra Utilities submits that the OEB should (i) establish the deferral accounts, as requested; and (ii) consider the generic policy and approach for LDCs to address such expenses that will be forthcoming, in the near future.

Finally, SEC, CCC, BOMA have suggested that the most appropriate manner in which to deal with these capital expenditures is for the LDC to use the ICM framework.[324] In fact, based on the size of the projects (in terms of dollars), and number of projects to be undertaken, if the only potential for relief for an LDC is to fund such work through base rates or through ICM, then the fact is that the government's policy regarding the revitalization/electrification of transportation systems will crowd out virtually all other necessary capital work due to the timing and sheer magnitude of the transportation work to be completed.

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[321] *Filing Requirements*, s. 2.9.6.

[322] Morrison Hershfield, *Final Utilities Impact Assessment Report for the GO Rail Network Electrification Transit Project Assessment Process*, prepared for Metrolinx, September 2017, p. 13 (Available at: http://www.gotransit.com/electrification/en/docs/technicalreports/GO%20Network%20Electrification%20TPAP_Final%20Utilities%20Impact%20Assessment%20Report_R5.pdf)

[323] Exhibit 2, Tab 3, Schedule 7, p. 3; Exhibit 2, Tab 4, Schedule 7, p. 3.

[324] CCC Submission, p. 15; BOMA Submission, p.72; SEC Submission, p. 19.

On this basis, Alectra Utilities requests that the OEB approve its request for two deferral accounts related to the Metrolinx projects, one in each of the PowerStream RZ and Enersource RZ.

Issue 3.2

What is the appropriate way to account for the change in capitalization policy resulting from the merger for Alectra Utilities and its predecessor companies?

In its Argument-in-Chief, Alectra Utilities argued that the OEB should order the closure of the capitalization related deferral accounts and the reversal of any amounts recorded in those accounts.[325] As Alectra Utilities explained, the capitalization policy change is a non-cash event that had no impact, and will have no impact going forward, on the underlying cost of utility business. Further, that OEB policy does not support any claim for rate adjustment at this time.[326] The Filing Requirements and MAADs policy are clear that, where a rebasing deferral period has been approved by the OEB for a consolidation transaction, accounting changes (including changes in capitalization policy) that are required within the consolidated entity pursuant to applicable accounting standards during the rebasing deferral period, are not to be reflected in rates until such time as the consolidated entity rebases.[327]

More particularly, in the MAADs Handbook, not only does the OEB contemplate that the benefits of a transaction will be received by the shareholders, but also that the costs are to be borne by shareholders. Specifically, the OEB states:

> Incremental transaction and integration costs are not generally recoverable through rates. Distributors have indicated that these costs are significant and that recovery of these costs can be a barrier to consolidation. To address distributors' concerns, the OEB issued a report on March 26, 2015 titled "*Rate-making Associated with Distributor Consolidation*" (2015 Report). In this report, the OEB has provided the opportunity for distributors to defer rebasing for a period up to ten years following the closing of a consolidation transaction. This deferred rebasing period is intended to enable distributors to fully realize anticipated efficiency gains from the transaction and retain achieved savings for a period of time to help offset the costs of the transaction.[328]

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[325] Argument-in-Chief, pp. 43-46.

[326] Ibid.

[327] *Filing Requirements*, Chapter 2, Cost of Service, s. 2.2.2.3; MAADs Handbook; MAADs Decision, EB-2016-0025, p. 16.

[328] MAADs Handbook, pp. 8-9.

The OEB reiterated this in the MAADs Decision.[329] The capitalization policy change is a function of the integration; the savings or costs arising from integration are to the account of the shareholder as specified in the MAADs Handbook and, more recently, in the MAADs Decision.

SEC and BOMA were the only parties to respond directly to Alectra Utilities' argument.[330] VECC notes its support for SEC but makes no argument of its own.[331] For their part, OEB staff and AMPCO also make no substantive submissions. They each presuppose the outcome of argument, ignore the direction of the OEB in Procedural Order No. 3 that this would be a matter for argument and assert that the balances in the capitalization related deferral accounts should be cleared in favour of ratepayers annually (AMPCO) or every two years (OEB staff).[332]

The argument that amounts in the capitalization deferral accounts should be cleared in favour of ratepayers is without merit. Again, it is inconsistent with OEB policy and would, if accepted, simply convert a non-cash accounting impact to the utility post-merger and within the rebasing deferral period into a cash outcome for customers, thereby appropriating an income impact arising from the merger that accrues to shareholders during the OEB approved 10 years rebasing deferral period.[333]

SEC devotes three pages of its argument to capitalization. These pages however ignore the governing OEB policy and requirements relied upon by Alectra Utilities.[334] Distilled to its essence, SEC's argument makes a single point: that Alectra Utilities seeks to recover the impact of the capitalization change in rates twice (at least to some extent as it asserts).[335] This position is fundamentally wrong. It is based on an incorrect view that Alectra Utilities would seek, and be permitted by the OEB to recover, amounts once through OM&A and again through rate base.

In paragraph 4.2.2 SEC says:

> There are certain expenditures that are being spent. They will continue to be spent. Right now, they are recovered through rates as part of the OM&A budget. **After the**

[329] EB-2016-0025, Decision of the Board, December 8, 2016, p.16

[330] BOMA Submission, pp. 69-72; SEC Submission, pp. 36-40.

[331] VECC Submission, paras. 54-61.

[332] OEB Staff Submission, pp. 60-61; AMPCO Submission, p. 27.

[333] *Filing Requirements*, Chapter 2, Cost of Service, s. 2.2.2.3; MAADs Handbook; MAADs Decision, EB-2016-0025, p. 16.

[334] SEC Submission, pp. 36-40.

[335] Ibid., paras. 4.2.5-4.2.6.

> **change, they are being added to rate base, to be recovered through rates over time. They will still remain in rates as part of the OM&A budget as well. [Emphasis added.]**

The emphasized passage of the above quote reflects SEC's misapprehension. But, nowhere has Alectra Utilities said that it should be entitled to recover the same amounts from ratepayers twice. Alectra Utilities has never said that it should recover amounts in rates now as though the capitalization change had not occurred and later be entitled to recover those same amounts through rate base as though it had. Of course, this should not happen. It would be wrong.

Alectra Utilities' position is much simpler. During a deferred rebasing period OEB policy is clear and base rates should not be changed, nor should amounts in those rates be extracted and included in deferral accounts to be disposed of to ratepayers.[336]

BOMA's assertion that the capitalization change qualifies for z-factor treatment is similarly wrong. Indeed, BOMA does not even explain how it could qualify.[337]

Z-factor treatment applies to matters which meet the OEB's established criteria, one of which is that the event be external to the utility.[338] Here, that is plainly not the case. As explained in Alectra Utilities' Argument in Chief, like all merging entities, it was required to adopt a uniform capitalization policy on merger across all of its rate zones.[339] Put differently, it was the <u>merger</u> that caused the change in capitalization policy. This was an event entirely within the control of then merging parties (now Alectra Utilities). If BOMA's argument were correct, the merger would be the Z-factor. This would mean that all costs and benefits under the transaction would be subject to scrutiny and adjustment. Plainly this would be wrong and inconsistent with the MAADs Handbook, as well as the MAADs Decision.

For the above reasons, Alectra Utilities repeats that the capitalization related accounts should be closed. The non-cash implications of accounting policy changes within a rebasing deferral period

[336] *Filing Requirements*, Chapter 2, Cost of Service, s. 2.2.2.3; MAADs Handbook; MAADs Decision, EB-2016-0025, p. 16.

[337] BOMA Submission, p. 71.

[338] *Filing Requirements*, Chapter 3, Incentive Rate-Setting Applications, s. 3.2.8.

[339] Argument-in-Chief, pp. 42-43.

should not be the subject of rate-making changes within the rebasing deferral period. This position is consistent with the MAADs policy and the OEB's decision in the MAADs Application.[340]

F. OTHER ISSUES RAISED

1. Monthly Billing

On April 15, 2015, the OEB amended the Distribution System Code ("DSC") and announced that all LDCs must migrate their residential and GS<50kW customers to monthly billing, no later than January 1, 2016.[341] Alectra Utilities identified in the Oral Hearing of its MAADs Application that it was seeking an exemption for the migration of the Horizon Utilities RZ customers and the Enersource RZ customers until the completion of its CIS implementation.[342] Subsequently, in its final submission, Alectra Utilities submitted that it could migrate its Horizon Utilities RZ customers to monthly billing by June 30, 2017.[343] It also identified the risks of implementing monthly billing for the Enersource RZ, while undertaking the CIS implementation. In its decision, the OEB granted Alectra Utilities the extension for the migration to monthly billing for the Horizon Utilities RZ to June 30, 2017 and the implementation for the Enersource RZ to 2019.[344]

Alectra Utilities did not seek any relief related to monthly billing in the current application.[345]

OEB staff did not make any submissions on monthly billing. VECC, BOMA and PWU did not make submissions on monthly billing, either

SEC submitted that the OEB should order creation of deferral accounts to track the cumulative impact of monthly billing for each of the affected rate zones.[346] Starting in 2019, whenever the cumulative net impact (savings less costs) is a credit, the accounts should be cleared by way of a refund to customers. The origin of the benefit is based on the assumption by SEC that the distributor, having

[340] MAADs Decision, EB-2016-0025, p. 16; MAADs Handbook.
[341] Notice of Amendment, Amendments to the Distribution System Code, April 15, 2015, pp. 2-3.
[342] EB-2016-0025, Oral Hearing, Day 5, pp. 6-7.
[343] Argument-in-Chief, p. 7.
[344] MAADs Decision, EB-2016-0025, p. 2.
[345] Exhibit 1, Tab 1, Schedule 1, pp. 13-20.
[346] SEC Submission, para. 5.2.3.

migrated its customers to monthly billing, must immediately change its working capital allowance percentage to the OEB default of 7.5%.[347] CCC and AMPCO supported the submission of SEC.[348]

The Application before the OEB is for electricity distribution rates effective January 1, 2018. Alectra Utilities' predecessor Hydro One Brampton had already implemented monthly billing. Its predecessor, PowerStream, implemented monthly billing as of January 1, 2017; and Alectra Utilities implemented monthly billing in the Horizon Utilities RZ as of June 30, 2018.

In a letter dated June 3, 2015, the OEB provided an update to its policy for the calculation of the allowance for working capital.[349] It reiterated its policy in the Filling Requirements as follows:

> The applicant may continue to take one of two approaches for the calculation of its allowance for working capital: (1) use a default allowance approach or (2) file a lead/lag study"…"The default allowance is 7.5% of the sum of Cost of Power (CoP) and OM&A.*[350]*

In the Horizon Utilities' Settlement Agreement, the Parties agreed, and the OEB approved, that Horizon Utilities would implement OEB policies, as necessary. As identified above, Alectra Utilities has done so, in the Horizon Utilities RZ.

The Settlement Agreement was clear and specific as to the areas that would be subject to annual update, and the areas within rate making that were subject to reopening rate setting.[351]

While policy implementations are permitted under the Settlement Agreement, Alectra Utilities does not have a reopener, nor an annual update for the working capital allowance ("WCA") percentage. In fact, the only requirement in the Horizon Utilities Settlement Agreement that pertains to monthly billing at all, is the requirement to implement policy changes.[352]

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[347] Letter from the OEB to All Licensed Electricity Distributors et. al. re Allowance for Working Capital for Electricity Distribution Rate Applications, June 3, 2015 ("Allowance for Working Capital Letter").

[348] CCC Submission, p. 16; AMPCO Submission, p. 28.

[349] Allowance for Working Capital Letter.

[350] Filling Requirements, Chapter 2, p. 17.

[351] Settlement Proposal, p. 29.

[352] Ibid.

In that case, the OEB's policy on monthly billing is clear: LDCs were required to implement it by January 1, 2017; Alectra Utilities was given a specific extension to June 30, 2017, for the Horizon Utilities RZ.[353] The potential change in WCA percentage change would only be implemented in cost of service, i.e., rebasing applications. In that case, an LDC could either take the OEB's WCA % default of 7.5%, as identified above, or file its own Lead/ Lag study.[354] In the event that the LDC was filing a Custom IR application, it was required to file its own Lead/ Lag study, in any event.[355]

Alectra Utilities submits that when Horizon Utilities filed its Custom IR, it did file an LDC-specific Lead/ Lag study.[356] Further, there are no reopeners or updates for the WCA% for the Horizon Utilities RZ. Alectra Utilities will file a Lead/Lag study at the time of its next Custom IR application.

However, in light of the foregoing, Alectra Utilities submits that there is no issue, nor any item that gives rise to a reduction in the WCA % and revenue requirement and subsequent return to customers.

2. Effective Date

Alectra Utilities has asked that final rates be made effective January 1, 2018. In its application, Alectra Utilities also asked that rates for each of its rate zones be made interim effective January 1, 2018 if a Decision and Order in this matter could not be issued by January 1.[357] In Procedural Order No. 3 dated November 17, 2017, the OEB granted Alectra Utilities' request for interim rates.[358]

SEC opposes Alectra Utilities' request for final rates effective January 1. It says rates should be effective on the first day following the OEB's rate order.[359] CCC and AMPCO adopt this submission.[360] OEB staff makes no submission, nor do BOMA, VECC or the PWU. In Alectra Utilities' submission there is no merit to the argument that rates should be effective later than January.

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[353] MAADs Decision, EB-2016-0025, p. 2.
[354] Allowance for Working Capital Letter, pp. 3-4.
[355] Ibid.
[356] EB-2014-0002, Exhibit 2, Tab 4, Schedule 1, Appendix 2-3.
[357] Exhibit 1, Tab 1, Schedule 1, p. 14.
[358] Decision on Issues List and Interim Rates and Procedural Order No. 3, November 17, 2017, p. 9.
[359] SEC Submission, p.43.
[360] CCC Submission, p. 16; AMPCO Submission, p. 28.

Alectra Utilities filed its application on July 7, 2017. This is in line with, or in advance of, any applicable guidance provided by the OEB.

On January 13, 2017, the OEB issued a letter identifying a preliminary list of distributors that were scheduled to file a COS application for 2018 rates. This letter also identified the OEB's filing deadline for Custom IR annual update applications, which is applicable to the Horizon Utilities RZ rate zone. The filing deadline was August 28, 2017.[361]

On July 20, 2017 – after Alectra Utilities had already filed – the OEB issued a cover letter for Chapter 1, 2 and 3 Updates. The letter identified the filing deadlines for 2018 IRM applications. There were four application groupings; group 1 applied to distributors applying for a January 1, 2018 effective date for rates. The filing deadline was August 14, 2017.[362]

The OEB has also provided processing timelines for various application types. Fairly characterized, this application falls somewhere between a standard and a streamlined written hearing. There has been no oral hearing. The processing time for these application types is 185 and 140 days, respectively. Alectra Utilities filed its application on day 188, leaving 177 days in 2017 to process the application.[363]

Finally, Alectra Utilities disagrees with the suggestion that there is a "normal practice" that rates should be effective only from the month following the OEB's rate order.[364] As recently as January 18, 2018, the OEB issued a decision making Union Gas' 2018 rates effective January 1, 2018 notwithstanding that the rate order was not issued until the date of the decision.[365] There can also be no concern about fairness or rate predictability because, by declaring rates interim both Alectra Utilities and ratepayers have known since last year that the amounts at issue are encumbered and subject to change.

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[361] Letter from the OEB to All Licensed Electricity Distributors re Applications for 2018 Electricity Rates, January 13, 2017.

[362] Letter from the OEB to All Licensed Electricity Distributors re I. Updated Filing Requirements & II. Process for 2018 Incentive Regulation Mechanism (IRM) Distribution Rate Applications, July 20, 2017.

[363] https://www.oeb.ca/industry/applications-oeb/performance-standards-processing-applications

[364] SEC Submission, para. 6.1.6.

[365] EB-2017-0087, Decision and Order, January 18, 2018, p. 15.

All of which is respectfully submitted this 30th day of January, 2018.

ALECTRA UTILITIES CORPORATION

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