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December 22, 2017

RESS, EMAIL & COURIER

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

Dear Ms. Walli:

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

We are counsel to the applicant, Alectra Utilities Corporation ("Alectra"), in the above-noted matter. In accordance with Procedural Order No. 3, issued by the Ontario Energy Board on November 17, 2017, please find enclosed Alectra's Argument-in-Chief. The Argument-in-Chief has been filed on RESS and a copy served on all parties.

Yours truly,

Crawford Smith

CS/tm
cc: All Parties
Indy Butany-DeSouza

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.

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ARGUMENT-IN-CHIEF

December 22, 2017

1.0 INTRODUCTION

Alectra Utilities Corporation ("Alectra Utilities" or the "Applicant") filed an application with the Ontario Energy Board ("OEB" or the "Board") 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"). The Application was prepared in accordance with the OEB's *Filing Requirements for Incentive Regulation Rate Applications* (the "Filing Requirements") and other relevant OEB guidance. This is Alectra Utilities' Argument-in-Chief in respect of the Application and is organized based on the approved issues list in this proceeding. For the reasons that follow, it is Alectra Utilities' submission that the Application should be approved as filed, and as updated during the proceeding.

2.0 OVERVIEW

In April 2016, Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, and PowerStream Inc. filed an application (the "MAADs Application"; EB-2016-0025), pursuant to the OEB's *Handbook to Electricity Distributor and Transmitter Consolidations*, dated January 19, 2016 (the "MAADs Handbook"), asking for approval to amalgamate to form Alectra Inc. and for Alectra to purchase and amalgamate with Hydro One Brampton Networks Inc. under section 86 of the *Ontario Energy Board Act 1998*. Alectra Inc. is the parent company of Alectra Utilities.

As part of the MAADs Application, approvals were sought: (a) to transfer the distribution licenses and rate orders for each of the applicants and Hydro One Brampton to Alectra Utilities; (b) for an electricity distributor licence for Alectra Utilities; and (c) for temporary exemptions from section 2.6.1A of the *Distribution System Code* ("DSC").

On December 8, 2016, the OEB issued its Decision and Order in respect of the MAADs Application. In the MAADs Decision, the OEB granted the requested approvals. It also approved a rebasing deferral period of 10 years. During the rebasing deferral period, any costs or benefits associated with or arising from the consolidation transaction are for the account of the Alectra Utilities' shareholder. As stated in the MAADs Decision, "the (March 26, 2015 report entitled *Rate-making Associated with Distributors Consolidation*) allows distributors to defer rebasing for a period up to ten years following the closing of a consolidation transaction in order to realize anticipated efficiency gains from the transaction and retain achieved savings for a period of time to help offset the costs of the transaction".[1] The OEB went on to find that the outcomes of the transaction were within the OEB's policy objective of improving the efficiency of electricity distribution, that customers would not be harmed and that customers would likely benefit in the long term from the enduring benefits arising from the transaction.[2]

During the rebasing deferral period, Alectra Utilities will operate individual rate zones (based on the predecessor utilities). As indicated in the MAADs Handbook as well as the previously issued *Report of the Board: Rate Making Associated with Distributor and Transmitter Consolidations* dated March 26, 2015, the Alectra Utilities rate zones will continue on their current rate plan terms until such terms expire. Once expired, all rate zones will migrate to the Price Cap Incentive Rate-setting ("Price Cap IR") option. At its option, Alectra Utilities is permitted to apply for (a) inflationary increases to rates, adjusted for an efficiency factor; and (b) funding of incremental discrete capital projects through the Incremental Capital Module ("ICM") mechanism.

At present, the Brampton, Enersource and PowerStream RZs are on Price Cap IR for the purpose of setting 2018 electricity distribution rates. The ICM is available to these rate zones.

[1] MAADs Decision, p. 16.

[2] MAADs Decision, p. 19.

In this Application, Alectra Utilities has applied for:

1. the Price Cap IR adjustment for the Brampton, Enersource and PowerStream RZs;

2. an annual adjustment for the Horizon Utilities RZ, related to the third adjustment in its 2015-2019 Custom IR rate plan term;

3. incremental capital funding for the Brampton, PowerStream and Enersource RZs; and

4. disposition of its Group 1 Deferral and Variance Accounts by rate zone, relating to variances accumulated in 2016, prior to the consolidation of Enersource, Horizon Utilities, Hydro One Brampton and PowerStream.

With respect to the Price Cap IR adjustments for the Brampton, PowerStream and Enersoure RZs, Alectra Utilities completed the IRM Model for each of these rate zones, as provided by the OEB, and updated the Application to include the 2018 IRM Rate Generator Model ("2018 IRM Model") once it was published by the OEB.[3] The IRM rate adjustments have been prepared in accordance with the updated *Chapter 3 of the Board's Filing Requirements for Electricity Distribution Rate Applications – 2016 Edition for 2017 Rate Applications* (the "Chapter 3 Filing Requirements"), dated July 14, 2016, including the key OEB reference documents listed therein, and the *Letter from the Board to Licensed Electricity Distributors re: I. Updated Filing Requirements; and, II. Process for 2018 Incentive Regulation Mechanism ("IRM") Distribution Rate Applications,* dated July 14, 2016.

For the Horizon RZ, the Settlement Agreement that was approved by the Board in the Custom IR proceeding (EB-2014-0002) includes agreement that the revenue requirement for each of the years 2015-2019 would be subject to annual adjustments, effective January 1 of each year. This is the third such annual filing for the Horizon RZ, made pursuant to and in accordance with the Decision of the Board in the Custom IR Application and the 2016 and 2017 annual filings. Alectra Utilities has calculated adjustments to its 2018 revenue requirement for the Horizon Utilities RZ using the Cost of Service Models and directions provided by the Board in July 2016 for 2017 filers. Alectra Utilities has used the IRM Model to determine disposition of the deferral and variance accounts for the

[3] G-Staff-2

Horizon Utilities RZ and the LRAMVA workform to determine the disposition of the LRAMVA balance resulting from CDM activities as of December 31, 2015.

Regarding the request for incremental capital funding, the OEB has confirmed that the ICM is available to consolidating distributors. The purpose of the ICM is to afford consolidating distributors an opportunity to finance capital investments without having to rebase earlier than expected. In the MAADs Decision, the OEB acknowledged that Alectra Utilities intended to file an ICM in each year for each rate zone under Price Cap IR during the rebasing deferral period. Alectra Utilities has capital 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 to meet these capital investment needs. Alectra Utilities has met the ICM requirements for each of these rate zones, as such requirements are set out in the OEB's Chapter 3 Filing Requirements; 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 "ACM Report"); and the *Report of the Board – New Policy Options for the Funding of Capital Investments: Supplemental Report*, dated January 22, 2016 (the "Supplemental Report").

As part of the Application, Alectra Utilities also filed a Distribution System Plan for the Enersource RZ for the 2018-2022 period (the "Enersource RZ DSP"). The Enersource RZ DSP forms the basis for the project-based funding relief sought for the Enersoure RZ ICM. The Enersource RZ DSP is consistent with the OEB's *Filing Requirements for Electricity Transmission and Distribution Applications – Chapter 5 Consolidated Distribution System Plans Filing Requirements* issued March 28, 2013 ("Chapter 5 Filing Requirements") and the RRFE. The Enersource RZ DSP describes 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. Alectra Utilities engaged Vanry Associates ("Vanry") to undertake an independent, third party review of the process and methodology used to develop the Enersource RZ DSP. Vanry found that the Enersource RZ DSP is well-reasoned and fact-based, that it reflects and was influenced by the desires and concerns of customers and stakeholders, and that the pacing of investments is reasonable and reflective of the need to balance between costs, performance obligations and risks.

Alectra Utilities engaged Innovative Research Group ("IRG") to undertake a multifaceted customer engagement program in respect of all four rate zones to understand the priorities and preferences of its customers. Alectra Utilities engaged with its customers to obtain specific feedback on the investment profile contemplated in the Enersource RZ DSP, as well as on the proposed ICM investments in each of the Brampton, PowerStream and Enersource RZs. With over 17,500 responses to the online portal, as well as surveys targeted at specific customer classes, this was by far the largest amount of customer feedback ever collected by an Ontario utility according to IRG. This engagement confirmed that the vast majority of customers are satisfied with the current level of reliability they experience, but that they expect Alectra Utilities to do what is necessary to maintain that level of reliability. As such, the feedback showed that most customers support some form of investment program that ensures a consistently reliable and modern distribution system that addresses growth and system demands, while also being sensitive to the frustration customers have with their electricity bills overall.

3.0 CUSTOM INCENTIVE RATE-SETTING (IR) 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?

The Year 4 Custom IR Update for the Horizon Utilities RZ is complete and has been filed in accordance with the framework accepted by the OEB in the approved Settlement Agreement from Horizon Utilities' Custom IR Application (EB-2014-0002), and as further articulated in the Board's Decisions and Orders in Horizon Utilities' 2016 and 2017 Annual Filings, as well as applicable OEB policies, practices and requirements. No departures are proposed.

Background

Horizon Utilities filed a Custom Incentive Rate-setting Application with the OEB on April 16, 2014 (EB-2014-0002) (the "Custom IR Application"), in which it sought approval for five years of distribution rates effective January 1 of each year from 2015 to 2019. A Settlement Proposal representing a partial settlement of the issues was filed with the Board on September 22, 2014. The

Settlement Proposal was accepted by the Board on October 10, 2014 and the Decision and Order on the remaining matters was issued December 11, 2014, for rates effective January 1, 2015.

The approved Settlement Agreement contemplates the filing of annual updates for rates to take effect on January 1 of each year during the Custom IR period. Horizon Utilities filed its second Annual Filing on August 11, 2016, for rates effective January 1, 2017, and the OEB issued its corresponding decision on January 12, 2017. That Annual Filing incorporated changes as a result of several Board policies and updated requirements.[4] The present Application includes the third Annual Filing for the Horizon Utilities RZ, for distribution rates and other charges to be effective January 1, 2018. This Annual Filing impacts the Applicant's customers in the Cities of Hamilton and St. Catharines. The specific relief sought through this Annual Filing for the Horizon Utilities RZ is set out at p. 3 of Exhibit 2, Tab 1, Schedule 1.

Annual Adjustments and Generic Policy Changes

As discussed in Exhibit 2, Tab 1, Schedule 2, the parties to the Settlement Agreement agreed to certain reopeners that had been proposed in the Custom IR Application. While some of the reopeners have not been triggered for this Annual Filing, the Applicant observes the following.

Generic Policy Changes

- *Changes to OEB policies on distributor rate design.* Alectra Utilities has incorporated the third year transition adjustment in its proposed rates for 2018 for the Horizon Utilities RZ and conducted the analysis on the 10th consumption percentile of energy consuming customers. This adjustment is discussed in further detail Exhibit 2, Tab 1, Schedule 4.

- *Ministerial Directives or similar required government action to provide a service to customers (such as the previous Smart Meter Deployment and CDM).* Horizon Utilities implemented the Ontario Energy Support Program ("OESP") on January 1, 2016 to provide support to eligible low-income customers. It was funded through electricity rates as a volumetric charge of $0.0011/kWh up until April 30, 2017 and is delivered as a reduction on qualifying customers' bills. In addition, Alectra Utilities has incorporated the removal of the OESP and reduction

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

to the RRRP charge in the Horizon Utilities RZ, in addition to the RPP changes, in its cost of power calculations, as a result of the introduction of the Ontario Fair Hydro Plan ("OFHP"). The RPP changes are discussed in further detail in Exhibit 2, Tab 1, Schedule 5. Updated cost of power calculations were provided in response to Undertaking JT.Staff-1.

- *Accounting framework changes that have a significant impact on the recording of expenses and revenues.* As discussed at p. 3 of Exhibit 2, Tab 1, Schedule 2, Alectra Utilities implemented a new capitalization policy in 2017 (following the consolidation) to align the capitalization policies for the Alectra Utilities rate zones. There is no revenue requirement impact of this to the 2018 Annual Filing for the Horizon Utilities RZ. This issue is discussed further below in relation to Issue 3.2.

- *Implementation of monthly billing.* Alectra Utilities implemented monthly billing for all residential and GS<50 kW customers in the Horizon Utilities RZ, effective June 23, 2017. The OEB extended the implementation of monthly billing for the Horizon Utilities RZ to June 30, 2017 in its Decision and Order on the MAADs application (EB-2016-0025).

- *Changes to the revenue allocated to unmetered load customers resulting from changes to the Board's policies on cost allocation for unmetered loads.* As discussed in Exhibit 2, Tab 1, Schedule 3, consistent with prior OEB decisions and policies, Alectra Utilities has derived its 2018 rates for the Horizon Utilities RZ using Version 3.4 of the Cost Allocation Model inclusive of the Street Lighting Adjustment Factor and the reduction to the RCR from 113.33% in 2017 to 106.66% in 2018.

Annual Adjustments

- *Changes in the Cost of Capital*. This Annual Filing was updated for the 2017 Cost of Capital parameters issued by the OEB on October 27, 2016. On November 23, 2017, the OEB issued the cost of capital parameters for 2018. Alectra Utilities will update these parameters, as applicable, for the Horizon Utilities RZ, when it prepares the Draft Rate Order**.**

- *Changes to working capital*. Alectra Utilities made changes to the working capital included in rate base for the Horizon Utilities RZ as a result of the changes to the Cost of Power.

Changes to the Cost of Power are discussed in Exhibit 2, Tab 1, Schedule 2 and are consistent with OEB policies and directions. Updates to the cost of power were provided in response to Undertaking JT.Staff-1.

- *CDM results that vary from plan.* As discussed in more detail under Issue 3.1 below, Alectra Utilities has proposed to dispose of the Account 1568 balance in this Annual Filing for the Horizon Utilities RZ. The balance in Account 1568 as at the end of December 31, 2015, as revised in Undertaking JTStaff-8, filed on December 15, 2017 was $1,339,931.

- *Disposition of deferral and variance accounts.* The balance in the Group 1 Deferral and Variance accounts for the Horizon Utilities RZ, as at December 31, 2016, exceeds the threshold test of $0.001/kWh. As such, Alectra Utilities requests disposition of the balances as presented in Table 1 of Exhibit 2, Tab 1, Schedule 2, and as revised in the IRM Model filed in response to Undertaking JT.Staff-3.

- *Any additional annual adjustments as identified by the Board in developing the Custom IR Application process*. The Settlement Agreement included three additional annual adjustments for: an Earnings Sharing Mechanism ("ESM"); a Capital Investment Variance Account ("CIVA"); and an Efficiency Adjustment.

    - *Earnings Sharing Mechanism*. For the purposes of earnings sharing, Alectra Utilities seeks approval for the calculation of its 2016 achieved ROE of 9.877% for the Horizon Utilities RZ,. Detailed discussion and calculations are provided in Exhibit 2, Tab 1, Schedule 6.

    - *Capital Investment Variance Account*. Alectra Utilities seeks approval of Horizon Utilities' 2016 capital additions of $44,295,265 as reported in its RRR 2.1.5.2 Capital filed April 28, 2017 for the purpose of calculating the 2016 entry to the Capital Investment Variance Account ("CIVA"). This compares to the forecasted capital additions for 2016 of $41,147,533, which were approved by the Board in Horizon Utilities' Settlement Agreement for its Custom IR Application (see Settlement Agreement, Table 9, page 33). As actual capital additions were higher than the capital additions forecast in the Custom IR Application, Alectra Utilities has not established or made an entry to the 1508 Sub-account CIVA for the Horizon Utilities RZ.

- *Efficiency Adjustment*. Based on the Board's Empirical Research in Support of Incentive Rate-Setting: 2013 Benchmarking Update for determination of Stretch Factor Assignments for 2015 dated August 14, 2014, no Efficiency Adjustment should be made to the revenue requirement for the 2018 Rate Year as per the Settlement Agreement.

Models

Alectra Utilities completed and provided a number of live models as part of its Annual Filing for the Horizon Utilities RZ, as detailed in Exhibit 2, Tab 1, Schedule 2 at pp. 13-15. Alectra Utilities has not made any material changes to the approved Work Forms and Models based on the Board's Decision on the Custom IR Application, with the exception of (i) updates to model versions released by the Board; (ii) updates as the result of changes to the Cost of Power flow-through costs and Cost of Capital parameters and (iii) the implementation of the new Cost Allocation Policy. Further, Alectra Utilities used the modified version of the IRM model for the disposition of the DVAs for the Horizon Utilities RZ. This is consistent with Alectra Utilities' practice for its other rate zones.

Issue 1.2

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

Alectra Utilities has appropriately adjusted the revenue to cost ratios for the Horizon RZ to reflect the OEB's Decision and Order in Horizon Utilities' 2016 Annual Filing proceeding (EB-2015-0075).

As described in Exhibit 2, Tab 1 Schedule 3, on June 12, 2015, the OEB revised its cost allocation policy for street lighting rate class so as to incorporate a "street lightning adjustment factor" ("SLAF") for allocating costs to street lighting class. The OEB also narrowed the revenue-to-cost ratio ("RCR") for the street lightning class to 80%-120%.

In its 2016 Annual Filing (EB-2015-0075), Horizon Utilities updated its 2016 cost allocation model with the SLAF. The impact of this update, together with certain other changes, was an increase in the RCR for the street lighting class from 81.35% to 160.09%. In its Decision and Order, the OEB directed that "the implementation of a RCR of 100% for street light class should be phased in, as has been the past practice, starting with a move to 120% for 2016. Moving the RCR to 100% should be done over subsequent years at a reduction of 6.6% per year for three years. This progression will assist in gradually phasing in the change".[5]

Pursuant to the OEB's direction to reduce the RCR for the Street Lighting Class from 120% in 2016 by 6.67% per year in each of 2017 to 2019, Alectra Utilities has updated its rate design model for 2018 to include a RCR 106.66% for the Street Lighting Class for the Horizon Utilities RZ. This corresponds to an increase in the RCR of 24.06% as compared to the RCR of 82.60% used in the 2015-2019 Custom IR Decision and prior to the revised Cost Allocation methodology.[6]

The 2018 RCR ratio in the 2018 cost allocation model inclusive of the SLAF was 114.15%. The first step in the rate design for 2018 was to reduce the RCR for the Street Lighting class from 114.15% to 106.66%. The next step was to adjust the RCR for those rate classes that were outside of the Board's Policy Range to the upper or lower end of the range, as applicable. There were no rate classes for which the RCR was outside of the Board's Policy Range %. The effect of the reduction in the RCR for the Street Lighting class was a revenue deficiency. The associated revenue deficiency was then allocated by way of an equal percentage to all rate classes that were below 100% RCR, with the exclusion of the Standby Class. This is consistent with Horizon Utilities' approach in its Custom IR Application, which was approved by the OEB in its Decision on the Application[7]. Based on the foregoing, the RCR for the Horizon RZ been appropriately adjusted to reflect the OEB's Decision and Order in EB-2015-0075.

4.0 INCENTIVE RATE-SETTING MECHANISM (IRM) 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?

The IRM Model filings for the Brampton, Enersource and PowerStream RZs are in accordance with applicable OEB policies, practices and requirements.

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[5] OEB, Decision and Order re Horizon Utilities Corp. (EB-2015-0075), December 10, 2015, p. 6.

[6] Exhibit 2, Tab 1, Schedule 3, p. 6.

[7] Page 10 of Horizon Utilities' Decision and Order, dated December 11, 2014.

In connection with Alectra Utilities' request for approval of distribution rates and other charges for the Brampton, PowerStream and Enersource RZs pursuant to the Price Cap IR regime, effective January 1, 2018, Alectra Utilities has completed the IRM Model as provided by the OEB for each of these rate zones. The Applicant will update the Application to include the 2018 IRM Rate Generator Model once it becomes available from the OEB.[8]

This aspect of the Application has been prepared in accordance with the Filing Requirements, including the key OEB reference documents listed therein, and the July 14, 2016 Letter from the Board to Licensed Electricity Distributors re: *I. Updated Filing Requirements; and, II. Process for 2018 Incentive Regulation Mechanism ("IRM") Distribution Rate Applications*. The specific relief sought for the three rate zones is set out in Exhibit 2, Tab 2, Schedule 1 (Brampton RZ), Exhibit 2, Tab 3, Schedule 1 (PowerStream RZ) and Exhibit 2, Tab 4, Schedule 1 (Enersource RZ).

In EB-2010-0379, the Board contracted Pacific Economics Group Research, LLC ("PEG") to prepare a report to the Board, entitled *Empirical Research in Support of Incentive Rate Setting in Ontario: Report to the Ontario Energy Board* (the "PEG Report"). The PEG Report established the parameters for use in determining the Price Cap Index for the 4th Generation IRM (now Price Cap IR), including a productivity factor of 0.00%, the approach to determine the Industry Specific Inflation Factor, and the initial stretch factor assignments.

Stretch Factor

The OEB issued the updated Stretch Factor assignments for 2018 IRM filers on August 17, 2017. In this Application, Alectra Utilities used a Stretch Factor of 0.3% for the Brampton and PowerStream RZs, and 0.15% for the Enersource RZ, each in accordance with the most recent PEG Report available at the time of filing the Application, which report was issued on August 4, 2016. The August 2017 report placed Hydro One Brampton and PowerStream in Group III and has moved Enersource to Group III for the purpose of calculating stretch factors for 2018.

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[8] The 2018 IRM Models were originally filed as Attachment 17 for the Brampton RZ, Attachment 26 for the PowerStream RZ and Attachment 39 for the Enersource RZ. As described in response to G-Staff-2, these models were updated and differences were identified between the Board's RGM and Alectra's IRM Model. As such, Alectra Utilities has continued to file both Alectra's IRM Model and the Board's RGM where updates are provided. Updated models were provided as G-Staff-2, Attachments 1 to 3. Further updates were provided for the PowerStream and Enersource RZs in response to Undertaking JTStaff-2 and JTStaff-5.

Inflation Factor

For each of the Brampton RZ, PowerStream RZ and Enersource RZ, the Price Cap Index (determined using the IRM Model for each specific RZ), based on the Board published inflation factor of 1.2%, is 0.9% for 2018.

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?

As described in Section 3.3.2 of the *Filing Requirements*, the ICM is a mechanism available to electricity distributors whose rates are established under the Price Cap IR regime. 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 may be applied to projects that might be considered to be 'routine' or 'business as usual'.[9]

The availability of ICM was litigated in the MAADs Decision, where Alectra Utilities advised that it intended to file ICM applications during the rebasing deferral period. Intervenors argued this should not be permitted. The Board disagreed and stated the following at p. 6 of the MAADs Decision:

> *The 2015 Report extended the availability of the Incremental Capital Module (ICM), an 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.*

The Brampton, Enersource and PowerStream RZs are on Price Cap IR for the purpose of setting 2018 electricity distribution rates. The ICM is available for each of these rate zones. The Horizon RZ is

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[9] ACM Report, pp. 5-8.

not eligible for the ICM because its 2018 distribution rates have been set in accordance with the Custom IR regime.

The *Filing Requirements* specify that the amount requested for an ICM claim must be incremental to the distributor's capital requirements within the context of its financial capacities underpinned by existing rates, and that the request must satisfy the eligibility criteria of materiality, need and prudence.[10] These criteria, discussed below, are as set out in section 4.1.5 of the *Report of the Board - New Policy Options for the Funding of Capital Investments: The Advanced Capital Module (*EB-2014-0219*)*, issued September 18, 2014 (the "ACM Report"). In addition, changes to the materiality threshold were made in the *Report of the OEB on New Policy Options for the Funding of Capital Investments: Supplemental Report* (EB-2014-0219), issued January 22, 2016 (the "Supplemental Report"). The ICM projects for the Brampton, Enersource and PowerStream RZs are in accordance with OEB policies, practices and requirements as reflected in the ACM Report, the Supplemental Report and the *Filing Requirements*. The Applicant is not proposing any departures therefrom.

Materiality

In the ACM Report, the Board 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.[11] 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 Board-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".[12]

The means for determining the Board-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.[13] Alectra Utilities has appropriately calculated the materiality thresholds, and the corresponding eligible incremental capital amounts (i.e. maximum amounts eligible for recovery

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[10] *Filing Requirements*, Section 3.3.2, p. 19.

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

[12] ACM Report, p. 17.

[13] 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.

through ICM), in accordance with the ACM Report, Supplemental Report, Filing Requirements and the *Report of the Board: Rate Making Associated with Distributor Consolidation*[14] for each of the Brampton, PowerStream and Enersource RZs. Based on the foregoing, the applicant has determined as follows:

- Brampton RZ has a maximum eligible incremental capital amount of $7,113,613.[15] The Applicant's proposal to recover $6,800,377[16] through the ICM in respect of the Brampton RZ is therefore within the range acceptable to the Board.

- PowerStream RZ has a maximum eligible incremental capital amount of $25,891,795.[17] The Applicant's proposal to recover $25,136,316[18] through the ICM in respect of the PowerStream RZ is therefore within the range acceptable to the Board.

- Enersource RZ has a maximum eligible incremental capital amount of $39,624,419.[19] The Applicant's proposal to recover $24,247,022[20] through the ICM in respect of the Enersource RZ is therefore within the range acceptable to the Board.

In addition to the materiality thresholds used for determining the total eligible incremental capital amounts for each rate zone, the Board requires distributors to meet project-specific materiality thresholds.[21] The project-specific materiality threshold, which has been defined by the Board as 0.5% of distribution revenue requirement,[22] has been calculated for each of the Brampton, PowerStream

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[14] See p. 10.

[15] Exhibit 2, Tab 2, Schedule 10, Table 66, p. 8

[16] Exhibit 2, Tab 2, Schedule 10, p. 9

[17] Exhibit 2, Tab 3, Schedule 10, Table 102, p. 19

[18] Exhibit 2, Tab 3, Schedule 10, Table 103, p. 20

[19] Exhibit 2, Tab 4, Schedule 11, Table 143, p. 30

[20] Exhibit 2, Tab 4, Schedule 11, Table 144, p. 31

[21] ACM Report, p. 17.

[22] 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."

and Enersource RZs and, in each rate zone, the individual eligible projects each exceed the identified project-specific materiality threshold, as follows:

- The project-specific materiality threshold for the Brampton RZ is $340,090. The one project for which ICM recovery is sought in this rate zone is well in excess of this threshold.[23]

- The project-specific materiality threshold for the PowerStream RZ is $997,500. Each of the ten projects for which ICM recovery is sought in this rate zone is in excess of this threshold.[24]

- The project-specific materiality threshold for the Enersource RZ is $589,950. Each of the eleven projects for which ICM recovery is sought in this rate zone is in excess of this threshold.[25]

Need

In the ACM Report, the Board 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.[26]

Under the Means Test, if a distributor's regulated return (as most recently calculated in accordance with Reporting and Record Keeping Requirements ("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.[27] The Applicant has demonstrated that, based on the accounts of the predecessor utilities, it has satisfied the Means Test in respect of each rate zone.[28]

Within the Brampton, PowerStream and Enersource rate zones, each eligible capital project is a discrete project that, as noted above, exceeds the corresponding project-specific materiality level.

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[23] Exhibit 2, Tab 2, Schedule 10, p. 10.
[24] Exhibit 2, Tab 3, Schedule 10, p. 21.
[25] Exhibit 2, Tab 4, Schedule 11, p. 32.
[26] ACM Report, p. 17.
[27] ACM Report, p. 15.
[28] 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).

Each project is distinct and has been evaluated in the asset management and capital planning process as required in 2018.[29] 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.[30] Moreover, the costs of the projects for which the Applicant seeks recovery through the ICM are incremental to the Applicant's capital requirements that underpin its existing rates for each rate zone.

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.[31]

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 various options considered for the project.[32] 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-

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[29] 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).

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

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

[32] 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).

service dates for the work.[33] Concise summaries of the business cases are provided in **Appendix 'A'** and the three largest eligible projects are highlighted below.

The three largest eligible projects consist of a System Access project in the PowerStream RZ, a System Renewal Project in the Enersource RZ, and a System Access project in the Brampton RZ, as follows:

- The Road Authority York Region Rapid Transit ("YRRT") VIVA Bus Rapid Transit Y2 and H2 Project is a System Access project in the PowerStream RZ with a budget of approximately \$11.24MM. System access investments are projects outside of Alectra Utilities' control that are required to meet customer service obligations to provide customers with access to electricity services via the distribution system and include modifications (including asset relocation) to the distribution system. This project is not included in distribution rates. The Applicant has been relocating overhead and underground distribution assets in the PowerStream RZ to accommodate the YRRT's Bus Rapid Transit developments, which is being undertaken to meet the transportation needs resulting from projected population growth in York Region. The current phase of the Bus Rapid Transit development is impacting the PowerStream RZ along two sections of Yonge Street totaling 6.5 km and two sections of Highway 7, as well as along several other roadways totaling 8.5 km. Alectra Utilities is obligated to relocate its distribution plant to facilitate transportation infrastructure developments by applicable road authorities in accordance with the *Public Service Works on Highways Act.* Alectra Utilities has committed to meeting the YRRT's established schedule for work in 2018 and has secured the necessary contractors to complete the required relocation of assets.[34]

- The Leaking Transformer Replacement Project is a System Renewal project in the Enersource RZ with a budget of approximately \$8.45MM for 2018. System renewal investments involve the replacement of aging equipment and/or refurbishment of distribution assets. As a result of inspections in 2013 to 2016, a large number of transformers were found to exhibit signs of oil leaks or contain PCB, which could lead to significant liabilities, in the event of spills. The

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

[34] See Technical Conference Transcript, Day 2, pp. 121-122

Applicant incurred $5.6MM in costs for environmental remediation and $19.4MM in capital expenditures for transformer replacements from 2013 to 2016, which were not included in rates. As of January 1, 2017, a total of 2,244 in-service transformers need to be replaced, including 1,629 units that were identified in the Kinectrics Asset Condition Assessment as being in poor or very poor condition as at year end 2015. This multi-year project is discrete, with the specific purpose of addressing an identified number of leaking transformers in a paced and organized manner.[35] Alectra Utilities is obligated by regulations to remediate all environmental contaminations due to leaking oil from transformers. Leaking transformers further deteriorate with time, leading to higher levels of oil contamination into the environment and increasing the cost to remediate.[36] Addressing the backlog of leaking transformers in a timely manner therefore reduces the need for significant environmental remediation costs. In 2018, this project will replace 543 of the 2,244 remaining transformers that have been identified as being in need of replacement.

- The Pleasant TS 10-Year True-Up is a System Access project in the Brampton RZ with a budget of approximately $6.8MM. System Access investments are mandatory upgrades to the distribution system, necessary to provide access to electrical services to customers. Drivers for such investments include customer service requests for connection, new development applications and road authority requests for the relocation of assets. Expansion of the Pleasant TS was required to address transformation capacity issues in the northwest area of Brampton, as well as needs due to anticipated load growth in the area.[37] Alectra Utilities experienced a lower than forecast energy demand in the Brampton RZ due to a downturn in the economy in 2008, government-driven conservation initiatives, as well as natural conservation. This reduced electrical demand at the Pleasant TS and has resulted in the need for an additional true-up payment due in 2018.[38] Pursuant to the Connection Cost Recovery Agreement ("CCRA") entered into at the time this station was constructed, Alectra Utilities was required to pay Hydro One Networks Inc. ("Hydro One") an initial capital contribution based on the difference between the total capital cost of constructing the station and a projection of

[35] See Technical Conference Transcript, Day 1, pp. 22-24
[36] See Technical Conference Transcript, Day 2, pp.168-169
[37] See Technical Conference Transcript, Day 1, pp. 106-107
[38] See Technical Conference Transcript, Day 1, pp. 99-104

transformation revenue to be earned by Hydro One on the conveyance of electricity through the station. The difference represents a contingent debt obligation for Alectra Utilities, based on the extent to which historical actual and forecast Hydro One revenue are less than the amount of the revenues Hydro One projected to earn as a basis for determining the initial capital contribution. The payment is classified based on the nature of the investment in the underlying project. The payment is non-discretionary and is incremental to the basis upon which rates were set for the Brampton RZ.

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***

The level of Alectra Utilities' planned capital expenditures for the ICM projects is appropriate. The Applicant has identified and prioritized the ICM projects, for each of the Brampton, PowerStream and Enersource RZs, through rigorous and sound methodologies that have considered its government-mandated obligations, reliability, impacts on OM&A spending and rates, all with regard to customer preferences and the need for appropriate pacing. The eligible ICM projects for which Alectra Utilities seeks approval reflect capital investment needs for each of these three rates zones for 2018, but which are not funded through existing distribution rates. Recovery through these ICM requests is therefore necessary to enable Alectra Utilities to meet these capital investment needs.

Capital Planning Methodologies

Alectra Utilities employs sound capital planning methods and processes for each of its rate zones, as documented in the corresponding distribution system plans.

Brampton

With respect to the Brampton RZ, as explained in Exhibit 2, Tab 2, Schedule 10, Hydro One Brampton filed a DSP for 2015 to 2019 in its 2015 Cost of Service Application (EB-2014-0083). This DSP was developed based on established asset management and capital expenditure planning practices that include investment portfolio optimization, work execution and continuous improvement. It was built around the strategy of centralizing key decision making in order to maximize the long-term effectiveness of investments while maintaining performance levels. The DSP also considered economic, service quality, community safety, legal and reputational risks. Hydro One Brampton and Intervenors filed a partial settlement proposal (the “Brampton Settlement Proposal”) that contemplated a capital budget of $37.9MM in 2015, which was ultimately accepted by the OEB.

The Hydro One Brampton DSP was designed to address capital expenditures across the four prescribed OEB categories: system access, system service, system renewal, and general plant. Hydro One Brampton’s Asset Management Process is the foundation of the DSP. The objective of this process is to invest in and maintain assets to achieve the lowest long-term cost of ownership while adhering to accepted design standards, construction codes and requirements, system performance targets and prescribed manufacturing specifications. The key elements of the process include: identifying needs based on multiple inputs; determining appropriate technical alternatives; developing business cases to address identified needs; assessing rate and customer impacts; executing planned projects and programs according to the business plan; and ensuring continuous improvement.

In the present Application, Alectra Utilities is seeking approval for incremental capital funding for its Brampton RZ for 2018 through distribution rate riders, as identified in Attachment 18 to the pre-filed evidence. Alectra Utilities has capital investment needs for the Brampton RZ that are not funded through existing distribution rates.

PowerStream

With respect to the PowerStream RZ, as explained in Exhibit 2, Tab 3, Schedule 10, PowerStream filed a five-year DSP (“PowerStream DSP”) for 2016 to 2020 in its Custom Incentive Rate Application (EB-2015-0003). The PowerStream DSP explained the processes, drivers, outcomes and justifications for the proposed capital investments PowerStream required to achieve its planning objectives. It incorporated PowerStream's integrated approach to planning, prioritizing and managing assets and consolidated the asset management processes that informed the capital investment plan. The PowerStream DSP also described activities such as regional planning, stakeholder engagement, considerations for renewable generation connections and smart grid developments. In its decision on August 4, 2016, the OEB disallowed PowerStream's proposed Custom IR framework and instead approved a single, forward test year cost of service application. It also approved capital spending of $115.8MM for 2017.

The PowerStream DSP was designed to address capital expenditures across each of the prescribed OEB categories: system access, system service, system renewal, and general plant. It provides justification regarding capital investments required for new connections, system capacity, system reliability, new technologies, renewal of sub-standard assets and general plant capital investments. The PowerStream DSP includes investments necessary to (i) ensure connection and system capacity are available to meet growth, and (ii) address and renew sub-standard assets to facilitate operational effectiveness and system reliability.

PowerStream's asset management planning process, identified in the PowerStream DSP, incorporates the key elements of asset knowledge, asset strategy and planning, asset management as well as decision-making and outputs. Capital projects are prioritized to realize the optimal value of projects and programs over the planning period across all four investment categories.

Alectra Utilities is seeking approval of incremental capital funding for the PowerStream RZ for 2018, through distribution rate riders as identified in Attachment 31 to the pre-filed evidence. Alectra Utilities has capital investment needs for this rate zone that are not funded through existing distribution rates. More particularly, the Applicant needs to increase investment in the PowerStream RZ for system access and service projects, and for renewal of aging distribution infrastructure; a theme articulated in its Custom IR Application (EB-2015-0003).

<u>Enersource</u>

With respect to the Enersource RZ, a DSP is included as part of this Application and is discussed in greater detail in response to Issue #2.5, below. Enersource last rebased in 2013.

Since 2014, key reliability metrics for the Enersource RZ (e.g. SAIDI, SAIFI) have been trending upward, indicating an overall deterioration in reliability performance. Alectra Utilities is committed to addressing this upward trend and reducing the associated operational risks (in particular, adverse impacts on the reliability and quality of distribution service provided to customers) as well as the resulting financial impact of increased system disturbances. Further, Alectra Utilities monitors and manages environmental and safety risks by continuing to enhance its asset inspection and testing practices, and maintaining or renewing assets found to pose risks to the environment, public health and/or safety.

The Comprehensive Asset Management Policy (“CAMP”) (attached as Appendix A to the DSP) has served as the foundation for the asset management strategy and practices that led to the development of Enersource RZ’s DSP. The CAMP is a set of principles for the stewardship and management of Enersource RZ assets to ensure an optimal balance between reliability performance and overall costs.

Through its capital planning process, and application of the CAMP, once Alectra Utilities selects the projects needed to address the relevant business risks, it prioritizes and paces all investments to ensure that the overall portfolio is reasonable with respect to the anticipated resource requirements and rate changes. These decisions take into consideration customer concerns and preferences identified through engagement efforts. Customers in the Enersource RZ have indicated a preference for Alectra Utilities to replace its distribution assets before failure to ensure that system performance and reliability are maintained.

As explained in Exhibit 2, Tab 4, Schedule 11, Alectra Utilities is seeking approval of incremental capital funding for the Enersource RZ for 2018, through distribution rate riders identified in Attachment 45 to the pre-filed evidence. Alectra Utilities has capital investment needs for the Enersource RZ that are not funded through existing distribution rates which, as set out above, were last rebased in 2013 have been adjusted mechanistically since then. These needs fall into the categories of system renewal, system access and system service.

Customer Engagement

The OEB’s *Handbook to Utility Rate Applications* 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".[39] To assist it in meeting this expectation, Alectra Utilities engaged IRG to undertake customer engagement for the Enersource RZ DSP,[40] as well as for the Applicant's other rate zones,[41] to help it understand the priorities and preferences of its customers.

With over 17,500 participants, the number of responses to the online portal was unprecedented. It was, by far, the most online customer feedback ever collected by IRG or, to its knowledge, the OEB. The engagement confirms that the vast majority of customers are satisfied with the current level of reliability they experience and expect Alectra Utilities to do what is necessary to maintain it. In principle, most customers were found to support some form of investment program that ensures a consistently reliable and modern distribution system and that also addresses growth and system demands. However, customers expressed frustration with their electricity bills and, when asked how Alectra Utilities can improve service, the most common responses were "nothing" or "lower rates".

Further details relating to the customer consultation carried out specifically in connection with the Enersource RZ DSP is considered in connection with Issue 2.5, below. IRG was available and gave evidence at the Technical Conference.

Key Rationale for ICM Projects

In total, for the Brampton, PowerStream and Enersource RZs, the Applicant is requesting approval for 22 discrete projects. Three of these projects are classified as System Access projects, 14 are System Renewal projects and 5 are System Service projects. The key rationale for the projects and their proposed timing are summarized in the table at Appendix A.

Revenue Requirement and Bill impacts

<u>Brampton</u>

[39] Handbook to Utility Rate Applications, October 13, 2016, p.11

[40] See Attachment 50 to the pre-filed evidence.

[41] See Attachment 51 to the pre-filed evidence.

For the Brampton RZ, the incremental revenue requirement associated with the ICM funding request of $6,800,377 is $706,794.[42] This revenue requirement has been allocated to rate classes based on the current allocation of revenue for the Brampton RZ using Tab 8 (Revenue Proportions for this Capital Module), filed as Attachment 18. The resulting ICM rate riders for the Brampton RZ are presented in Table 68.[43] The bill impacts resulting from the ICM rate riders in the Brampton RZ, which are derived by comparison to the total bill including HST, range from under 0.02% for Embedded Distributors to 0.8% for Distributed Generation customers.[44]

PowerStream

For the PowerStream RZ, the incremental revenue requirement associated with the ICM funding request of $25,136,316 is $1,834,693.[45] This revenue requirement has been allocated to rate classes based on the current allocation of revenue for the PowerStream RZ using Tab 8 (Revenue Proportions for this Capital Module), filed as Attachment 31. The resulting ICM rate riders for the PowerStream RZ are presented in Table 106.[46] The bill impacts resulting from the ICM rate riders in the PowerStream RZ, which are derived by comparison to the total bill including HST, range from under 0.02% for Street Lighting to 0.3% for Unmetered.[47]

[42] Exhibit 2, Tab 2, Schedule 10, Table 67, p. 12
[43] Exhibit 2, Tab 2, Schedule 10, Table 68, p. 13
[44] Exhibit 2, Tab 2, Schedule 10, p. 14.
[45] Exhibit 2, Tab 3, Schedule 10, p. 33.
[46] Exhibit 2, Tab 3, Schedule 10, p. 36.
[47] Exhibit 2, Tab 3, Schedule 10, p. 36.

<u>Enersource</u>

For the Enersource RZ, the incremental revenue requirement associated with the ICM funding request of $24,247,022 is $1,962,111.[48] This revenue requirement has been allocated to rate classes based on the current allocation of revenue for the Enersource RZ using Tab 8 (Revenue Proportions for this Capital Module), filed as Attachment 45. The resulting ICM rate riders for the Enersource RZ are presented in Table 147.[49] The bill impacts resulting from the ICM rate riders in the Brampton RZ, which are derived by comparison to the total bill including HST, range from 0.1% for the General Service 50 to 499 kW and Large Use classes to 0.6% for Street Lighting.[50]

Issue 2.4

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

Alectra Utilities intends to carry out the ICM true-ups at its next rebasing in accordance with OEB policy. Specifically, as explained in response to CCC-7, Alectra Utilities refers to OEB policy as described in Section 7.4 of the *Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, dated September 18, 2014, which explains as follows:

> *At the time of the next cost of service or Custom IR application, a distributor will need to file calculations showing the actual ACM/ICM amounts to be incorporated into the test year rate base. At that time, the Board will make a determination on the treatment of any difference between forecasted and actual capital spending under the ACM/ICM, if applicable, and the amounts recovered through ACM/ICM rate riders and what should have been recovered in the historical period during the preceding Price Cap IR plan term. Where there is a material difference between what was collected based on the approved ACM/ICM rate riders and what should have been recovered as the revenue requirement for the approved ACM/ICM project(s), based on actual amounts, the Board may direct that over- or under-collection be refunded or recovered from the distributor's ratepayers.*

Moreover, during the Technical Conference, the Applicant confirmed that in seeking approvals for the ICM true-ups at its next rebasing, the Applicant will report on the same basis as it has in response to Board Staff-3, namely that it will report at a project level.[51]

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[48] Exhibit 2, Tab 4, Schedule 11, p. 46.

[49] Exhibit 2, Tab 4, Schedule 11, p. 48.

[50] Exhibit 2, Tab 4, Schedule 11, p. 49.

[51] Transcript, Day 2 Technical Conference, p. 133.

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?

OEB-approved DSPs are in place for all of Alectra Utilities' rate zones other than the Enersource RZ. As such, as part of this Application, and to support the Applicant's request for incremental capital for the Enersource RZ, Alectra Utilities has filed a DSP for the Enersource RZ for a five-year term from 2018 to 2022 (the "Enersource RZ DSP").[52]

The Enersource RZ DSP includes sufficient information to support the proposed ICM for the Enersource RZ. It provides justification for Enersource RZ proposed expenditures 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 Enersource RZ DSP includes detailed information regarding (i) significant projects to be undertaken and their drivers, (ii) relationships between investments and the Applicant's objectives for the Enersource RZ, (iii) factors affecting the timing for investments, (iv) the capacity of the Enersource RZ's distribution system to connect new load and embedded generation, and (v) an overview of Alectra Utilities' capital expenditure planning process for the Enersource RZ.

As explained in Exhibit 2, Tab 4, Schedule 11, the Enersource RZ DSP has been developed in accordance with Chapter 5 of the Filing Requirements and in alignment with the RRFE. In formulating the DSP and capital expenditures plan for the Enersource RZ, Alectra Utilities took into account the following business values, in alignment with the RRFE: (i) regulatory/public policy responsiveness; (ii) operational effectiveness; (iii) customer focus; and (iv) financial performance.

Alectra Utilities prioritizes its investment proposals for the Enersource RZ based on their expected impact on the aforementioned business values, which are better understood in terms of the associated risks, namely operational risk, environmental risk, financial risk and safety/regulatory risk.[53] Of particular significance for this rate zone is that (i) SAIDI and SAIFI have been trending upward, reflecting the deteriorating condition of distribution assets and the resulting impact on service quality

[52] 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.

[53] See Exhibit 2, Tab 4, Schedule 11, pp. 3-4.

in the Enersource RZ; (ii) certain distribution transformers require replacement due to signs of oil leaks, as identified by Alectra Utilities through rigorous inspection efforts; (iii) certain mandatory projects driven by public transit and road works, as well as to meet growing capacity requirements within the Enersource RZ, must be implemented; and (iv) a significant portion of the underground system, which contains cables that are at the end of useful life and were built according to outdated standards, is prone to failure and poses a safety risk to workers and the public.

Asset Management Practices

To develop the Enersource RZ DSP, the Applicant began by assessing external drivers (e.g. regulatory requirements, regional planning, renewable generation), internal drivers (e.g. asset conditions and performance, corporate objectives, service quality targets), as well as other relevant investment considerations (e.g. customer preferences, system enhancement needs, and technical requirements). Based on these inputs, Alectra Utilities identified the investment needs and potential projects for the Enersource RZ.

The DSP includes both mandatory and discretionary investments. Mandatory investments are those driven by statutory, regulatory or contractual obligations that Alectra Utilities must meet. All other projects are discretionary. Each project was categorized, based on primary investment drivers, using the investment categories set out by the Chapter 5 Filing Requirements (i.e. System Access, System Renewal, System Service, General Plant).

As explained in Exhibit 2, Tab 4, Schedule 11, the available technical alternatives for each project were evaluated and compared to enable the Applicant to determine the preferable solution for addressing the relevant business risks and balancing competing priorities in the most efficient and cost effective manner. Once the proposed projects were gathered from all business units, Alectra Utilities prioritized its investment portfolio by ranking projects based on their ability to address the most important investment needs and their expected impact on underlying business values (i.e. regulatory and public policy responsiveness, operational effectiveness, customer focus, and financial performance).

Mandatory, non-discretionary, investments were prioritized first. For both mandatory and discretionary projects, a key input into the capital investment planning process is the estimated financial impact resulting from the proposed projects. More specifically, individual projects were evaluated based on cost efficiency and projected savings, the ongoing costs expected to be incurred as the result of a project, and the project's expected rate impact. Once these aspects were well understood, other relevant considerations such as customer preferences and resource availability were considered to ensure that the overall investment portfolio is appropriately paced throughout the DSP period.

Capital Expenditure Portfolio

The key drivers for investments in the Enersource RZ DSP, by investment category, are as follows:

- System Access - Investments in the expansion and modification (including asset relocation) of Enersource RZ's distribution system to provide customers with access to adequate distribution services. Key drivers include intensification growth in the downtown core of Mississauga and the implementation of the Light Rail Transit ("LRT") system.

- System Renewal - Investments address assets performing at a sub-standard level. Key drivers include areas requiring renewal based on asset condition assessment, inspection records and system performance trends, consequences of asset performance deterioration or failure, asset performance-related operational targets, asset lifecycle optimization practices and the number of customers affected by asset failures.

- System Service - Investments are driven by load growth in specific areas of the rate zone, which cannot currently be met by the distribution system, and by system operational constraints that need to be eliminated. The City of Mississauga's development plans, regional planning processes and technological innovations are key drivers to improve operational efficiency.

- General Plant - Investments support requirements for business operations and address findings from condition assessments of facilities and fleet assets. In light of the formation of Alectra Utilities in February 2017, certain General Plant investments will be executed by Alectra Utilities as a consolidated entity, with transition expenditures borne by the shareholders of Alectra Utilities.

The main distribution system investments that underpin the Enersource RZ DSP reflect three key drivers:

- the need to address load growth in specific areas of Mississauga and capital works made necessary by major infrastructure projects such as the LRT;
- the need to address the deteriorating condition of a portion of the Enersource RZ's distribution assets; and
- the need to mitigate, in a timely manner, environmental risks stemming from distribution transformers that exhibit signs of oil leaks.[54]

Based on the evaluation of business values and relevant investment drivers, Alectra Utilities developed program and project business cases for each investment category, which are included in the Enersource RZ DSP. These business cases were then used to establish the near- to mid-term capital expenditure forecasts, as set out in the Enersource RZ DSP.

Customer Engagement

To identify and account for customer preferences and needs, Enersource proactively engaged its customers in a variety of ways, including through previously conducted customer satisfaction surveys that helped the utility understand key changes and trends in customers' perceptions and concerns over time. As indicated by the results of a 2014 survey, Mississauga customers generally rated the quality of service they experienced as being comparable to or better than the national and provincial survey averages. At the same time, the cost of electricity was a focus area for a sizeable segment of Mississauga customers. In this regard, the need for reasonable rates, followed by system reliability improvements, was identified as the top customer priority.

Alectra Utilities engaged IRG to solicit customer feedback on its draft DSP, as well as proposed incremental capital funding for the Enersource RZ. The IRG Report is filed as Attachment 51 to the pre-filed evidence. IRG designed and assisted the Applicant in implementing a multifaceted customer engagement program to collect feedback from multiple rate classes across multiple rate zones,

[54] See Exhibit 2, Tab 4, Schedule 11, pp. 6-16.

including the Enersource RZ. The program included a voluntary online feedback portal, telephone surveys with Residential and General Service customers, and an invitation-only online survey to canvass the views of Large Users (5MW+).

The Applicant's customer engagement efforts have confirmed that the vast majority of customers are satisfied with the current level of reliability they experience, and expect Alectra Utilities to do what is necessary to maintain it. In principle, most customers support some form of investment program that ensures a consistently reliable and modern distribution system, that also addresses growth and system demands. Customers also expressed frustration in relation to their electricity bills. When asked how Alectra Utilities can improve service, most common responses throughout the engagement were either "nothing" or "lower rates".

In carrying out the customer engagement, Alectra Utilities determined the maximum eligible capital it could apply for in the Enersource RZ, based on its most recent 2018 capital forecast of $83,118,772, before incorporating customer preferences, and its materiality threshold of $43,494,353. The difference between the 2018 capital forecast, before incorporating customer preferences, and the materiality threshold was $39,624,419.[55] During the engagement activities, customers were presented with the 2018 bill impacts associated with implementation of the projects listed in Table 137 of the pre-filed evidence, which represented a total capital expenditure of $28,643,339.

Based on feedback received, Alectra Utilities revised its ICM request downwards to $24,247,022 by removing an approximately $4.4M station construction project that has been deferred. In addition, the Enersource RZ DSP reflects additional deferrals of System Service projects (Mini-Britannia MS and Duke MS), paced investments relating to the LRT project, and an increased focus on CDM opportunities in certain areas of Mississauga (particularly in the Downtown Core) so as to offset expected load growth in the near term.[56] These measures demonstrate that the Applicant has appropriately adjusted its planned capital expenditures to account for the priorities and preferences of its customers.

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[55] Exhibit 2, Tab 4, Schedule 11, p. 24.
[56] Exhibit 2, Tab 4, Schedule 11, p. 28.

Third Party Expert Review

Vanry Associates ("Vanry") was retained to undertake an independent, third party review of the process and methodology used to develop the Enersource RZ DSP. Their review involved careful consideration of Alectra Utilities' asset management practices in the Enersource RZ to understand the linkages between the inputs that drive investment needs, the processes used to prioritize and pace investments and specific performance outcomes. In Vanry's professional opinion, 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 is evident that the customer engagement results have influenced the focus of the DSP as well as the associated investment planning." Vanry further concludes from its review of the Enersource RZ DSP that:

> *The proposed investment plans align with what we see as being needed by the system to deliver the required performance levels and to meet the regulatory requirements. The pacing of the investments appears reasonable and reflective of a need to balance between costs and performance 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.*

Despite its report being filed as part of the Application, no party asked a single question of Vanry. Its conclusions are unchallenged.

5.0 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?

Alectra Utilities' proposals for deferral and variance accounts, including the balances in its existing accounts and their disposition, requests for new accounts and the continuation of existing accounts are appropriate for the reasons that follow.

Disposition of Group 1 Deferral and Variance Account Balances

Alectra Utilities has requested disposition of its Group 1 Deferral and Variance Accounts by rate zone. The proposed balances relate to variances accumulated in 2016. More particularly, for each of the four rate zones, Alectra Utilities requests disposition of its adjusted Group 1 balances, which have been updated during the proceeding in response to interrogatories and undertakings, as follows:

- For Horizon Utilities RZ, Group 1 balances of ($7,370,171), identified in Table 36, through the rate riders identified in Table 37 found in Exhibit 2, Tab 1, Schedule 7. Although the total balance identified in the pre-filed evidence remains accurate, in response to undertaking JT.Staff-3 Alectra Utilities provided an update to the balances in accounts 1588 and 1589;

- For Brampton RZ, Group1 balances of ($5,732,154), identified in Table 56, through the rate riders identified in Table 57 found in Exhibit 2, Tab 2, Schedule 5;

- For PowerStream RZ Group1 balances of ($20,550,622), identified in the updated IRM model provided in response to undertaking JT.Staff-5; and

- For Enersource RZ Group 1 balances of ($7,401,082), identified in the updated IRM model provided in response to undertaking JT.Staff-2.

As discussed in the pre-filed evidence, in order to determine the amount for disposition, Alectra Utilities made the following adjustments to the Group 1 balances for each of the rate zones:[57]

- Only residual balances in Account 1595 for which rate riders have expired were included;

- RPP settlement true-up claims for a given fiscal year that have not been included in the audited financial statements must be identified separately as an adjustment to the balance requested for disposition as directed in the OEB's letter dated May 23, 2017 on the *Guidance on the Disposition of Accounts 1588 and 1589*. As described in the pre-filed evidence, Alectra Utilities followed the OEB direction and made the necessary adjustments[58];

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

[58] Refer Exhibit 2, Tab 2, Schedule 5, for Brampton RZ; Exhibit 2, Tab 3, Schedule 5, for PowerStream RZ; Exhibit 2, Tab 4, Schedule 5, for Enersource RZ.

- Only Class B Capacity Based Recovery ("CBR") amounts are to be disposed of through this rate proceeding as directed by the OEB in its *Accounting Guidance on Capacity Based Recovery* issued July 25, 2016; and

- Projected carrying charges for each Group 1 Account balance to the proposed rate rider implementation date are included (i.e. the amount for disposition includes 2017 projected carrying charges).

Alectra Utilities has applied the appropriate calculations in determining the disposition threshold for each rate zone:

- For the Horizon Utilities and for the Brampton RZs, based on the adjusted Group 1 balances, to be ($0.0014)/kWh, as identified in the Tables 32 and 52, found in Exhibit 2, Tab 1, Schedule 7, and Exhibit 2, Tab 2, Schedule 5, respectively;

- For the PowerStream RZ, based on the adjusted Group 1 balances to be ($0.0030)/kWh, as identified in Table 77, found in Exhibit 2, Tab 3, Schedule 5; and

- For the Enersource RZ, based on the adjusted Group 1 balances to be ($0.0012)/kWh, as identified in Table 115, found in Exhibit 2, Tab 4, Schedule 5.

Alectra Utilities has completed Tab 3 - Continuity Schedule of the IRM Model for each of the Alectra Utilities' rate zones.[59] Alectra Utilities has reconciled the Group 1 balances for Horizon Utilities, Hydro One Brampton, PowerStream and Enersource filed in the 2016 RRR, section 2.1.7.

As identified in Exhibit 2, Tab 1, Schedule 7; Exhibit 2, Tab 2, Schedule 5; and Exhibit 2, Tab 4, Schedule 5, Alectra Utilities confirmed that the last Board-approved balance for each of the Horizon Utilities, Brampton and Enersource RZs has been transferred to Account 1595. Alectra Utilities has also confirmed the accuracy of the billing determinants to the 2016 RRR, section 2.1.5.4. Alectra Utilities relied upon the Board's prescribed interest rates to calculate carrying charges on the deferral

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[59] Filed as Attachment 6 for Horizon Utilities RZ, Attachment 17 for Brampton RZ, Attachment 26 for PowerStream and Attachment 39 for Enersource RZ.

and variance account balances. The prescribed interest rate of 1.10% was relied upon to calculate forecasted interest for 2017.

Alectra Utilities is seeking a one-year disposition period for the Group 1 balances for each of the Alectra Utilities' rate zones. This approach is consistent with the EDDVAR Report which states that "the default disposition period used to clear the account balances through a rate rider should be one year".[60]

Wholesale Market Participants ("WMPs")

WMPs participate directly in the IESO-administered market and settle commodity and market-related charges directly with the IESO. Alectra Utilities has established separate rate riders to dispose of the balances in the RSVAs for WMPs for each of the four rate zones. The balances in Account 1588 RSVA – Power, Account 1580 RSVA – Wholesale Market Service Charge (including CBR) and Account 1589 RSVA – Global Adjustment have not been allocated to WMPs.

Global Adjustment and Capacity Based Response Disposition

Alectra Utilities has established separate rate riders for each of the four rate zones to dispose of the global adjustment ("GA") and Capacity Based Response ("CBR") account balances. The GA rate riders are applicable to non-RPP Class B customers only and the CBR rate riders are applicable to Class B customers only. Alectra Utilities' Class A customers are invoiced the actual GA and, as such, none of the variance in the GA account balance should be attributed to these customers. In the PowerStream RZ, non-RPP Class B interval metered customers are billed based on the actual GA rate per kWh and, as such, none of the variance in the GA account balance should be attributed to these customers.

As discussed in Exhibit 2, Tab 1, Schedule 7, and updated in the latest IRM model that was filed in response to undertaking JT.Staff-3, Alectra Utilities requests disposition of its GA balance of ($124,069) and its CBR balance of ($2,060) related to its three new Class A customers and two new

[60] EDDVAR, p. 6.

Class B customers (effective July 1, 2016), respectively, through the bill adjustments identified in the IRM Model for the Horizon Utilities RZ.

As discussed in Exhibit 2, Tab 2, Schedule 5, Alectra Utilities requests disposition of its GA balance of ($30,997) and its CBR balance of ($1,005) related to its three new Class A customers and one new Class B customer for the Brampton RZ (effective July 1, 2016), respectively, through the bill adjustments identified in the IRM Model.

As discussed in Exhibit 2, Tab 3, Schedule 5, and as updated in the latest IRM model that was filed in response to undertaking JT.Staff-5, Alectra Utilities requests disposition of its CBR balance of $22,566 related to its new Class A customers (effective July 1, 2015 and July 1, 2016) and new Class B customers (effective July 1, 2016) through the bill adjustments identified in the IRM Model for the PowerStream RZ.

As discussed in Exhibit 2, Tab 4, Schedule 5, Alectra Utilities requests disposition of its GA balance for the Enersource RZ of $10,164 and its CBR balance of $1,676 related to its two new Class A customers (effective July 1, 2016) through the bill adjustments identified in the IRM Model.

Alectra Utilities requests disposition of the CBR B rate rider to the fifth decimal place for the Horizon Utilities RZ and Enersource RZ. The OEB indicates in the Treatment of Negligible Rate Adders and Rate Riders on page 26 of the Chapter 3 Filing Requirements that:

> *In the event where the calculation of any rate adder or rate rider results in a volumetric rate rider that rounds to zero at five significant digits (i.e., the fourth decimal place) per kWh or per kW, the entire OEB-approved amount for recovery or refund will typically be recorded in a USoA account to be determined by the OEB for disposition in a future rate setting.*

However, Alectra Utilities proposes that the CBR B balance be cleared with a volumetric rate rider to five decimal places in 2018 for the Enersource RZ and the Horizon RZ, as identified in the application and in response to G-Staff-4. 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 inequity.

For a typical RPP Residential customer consuming 750 kWh per month, the total monthly bill impact of the proposed Group 1 rate riders is as follows:

- For the Horizon Utilities RZ, a decrease of ($0.49)/month or (0.44%) on the total bill;[61]
- For the Brampton RZ, a decrease of ($0.75)/month or (0.7%) on the total bill;[62]
- For the PowerStream RZ, a decrease of ($1.95) /month or (1.8%) on the total bill;[63] and
- For the Enersource RZ, an increase of ($0.56)/month or (0.52%) on the total bill.[64]

Disposition of LRAM Variance Account

Alectra Utilities has requested disposition of the balances in its Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA") resulting from its Conservation and Demand Management ("CDM") activities as of December 31, 2015 for each of the Horizon Utilities, PowerStream and Enersource RZs. The former Hydro One Brampton disposed of the balances in its LRAMVA as of December 31, 2015, as part of its 2017 IRM application (EB 2016-0080) so LRAMVA disposition is not sought for the Brampton RZ in this Application.

Horizon Utilities' most recent application for the recovery of lost revenues due to CDM activities was filed in its Custom IR application (EB-2014-0002). In that proceeding, the Board approved Horizon Utilities' request to recover lost revenues from CDM activities in 2011 and 2012. Horizon Utilities' actual savings from CDM activities for 2013 through 2015 were above the estimated projections used in the load forecast resulting in an under-collection from customers during this period. The total amount requested for disposition in this Application is a debit of $1,339,931 including forecasted carrying charges of $51,220 through to December 31, 2017.[65] The total amount in LRAMVA for the Horizon Utilities RZ is above the materiality threshold, as discussed in Exhibit 2, Tab 1, Schedule 9.

PowerStream's most recent application for the recovery of lost revenues due to CDM activities was filed in its Custom IR Application (EB-2015-0003). In that proceeding, the Board approved PowerStream's request to recover lost revenues from CDM activities in 2013. Actual savings from CDM activities for 2014 and 2015 in PowerStream RZ were above the estimated projections used in the load forecast resulting in an under-collection from customers during this period. The total amount

[61] See updated IRM model filed in response to JT.Staff-3.
[62] See updated IRM model filed in response to G-Staff-2.
[63] See updated IRM model filed in response to JT.Staff-5.
[64] See updated IRM model filed in response to JT.Staff-2.
[65] JT.Staff-8, Attachment 1.

requested for disposition in this Application is a debit of $1,977,404 including forecasted carrying charges of $62,106 through to December 31, 2017.[66] The total amount in LRAMVA for the PowerStream RZ is above the materiality threshold, as discussed in Exhibit 2, Tab 3, Schedule 9.

Enersource's most recent application for the recovery of lost revenues due to CDM activities was filed in EB-2013-0024. In that proceeding, the Board approved Enersource's request to recover lost revenues from persisting historical impacts of pre-2011 CDM programs in 2011 and 2012. Enersource's actual savings from CDM activities for 2011 through 2015 were above the estimated projections used in the load forecast resulting in an under-collection from customers during this period. The total amount requested for disposition in this Application is a debit of $2,077,134 including forecasted carrying charges of $102,149 through to December 31, 2017.[67] The total amount in LRAMVA for the Enersource RZ is above the materiality threshold, as discussed in Exhibit 2, Tab 4, Schedule 9.

For each of these three rate zones, Alectra Utilities has determined the LRAM amount in accordance with the Board's 2012 CDM Guidelines, 2015 CDM Guidelines and its 2016 Updated Policy for the calculation of LRAMVA in respect of peak demand savings. Alectra Utilities has completed the 2018 LRAMVA work form for each of the three rate zones provided by the OEB to calculate the variance between actual CDM savings and forecast CDM savings.[68] In accordance with the OEB's 2016 Updated Policy on the calculation of peak demand savings, Alectra Utilities has not included peak demand (kW) savings from Demand Response programs for the Horizon Utilities, PowerStream and Enersource RZs in its lost revenue calculation.

In accordance with the Chapter 3 Filing Requirements, Alectra Utilities has provided the following information as part of its pre-files evidence:

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[66] JT.Staff-8, Attachment 2.

[67] JT.Staff-8, Attachment 3.

[68] The LRAMVA work form has been filed as a working Microsoft Excel file as directed by the Board in the Chapter 3 Filing Requirements issued by the OEB on July 14, 2016, and is provided in Attachment 11 for Horizon Utilities RZ, Attachment 28 for PowerStream RZ, Attachment 42 for Enersource RZ.

(i) Alectra Utilities has used the most recent input assumptions available at the time of the program evaluation when calculating its lost revenue amount for each of the three rate zones; and

(ii) Alectra Utilities has relied on the most recent and appropriate final CDM evaluation report from the IESO in support of its lost revenue calculation for each of the three rate zones.[69]

Detailed calculations of the LRAMVA threshold, carrying charges, lost revenue calculations by year for each rate class are presented in Exhibit 2, Tab 1, Schedule 9, of the pre-filed evidence for the Horizon Utilities RZ; at Exhibit 2, Tab 3, Schedule 9, of the pre-filed evidence for the PowerStream RZ; and at Exhibit 2, Tab 4, Schedule 9, of the pre-filed evidence for the Enersource RZ. The detailed calculations have been updated based on Alectra Utililties' response to undertaking JT.Staff-8.

Brampton RZ

In this Application, Alectra Utilities is not applying for rate riders associated with its 2016 LRAMVA account balances in the Brampton RZ. As per the Decision and Order in the Hydro One Brampton 2017 IRM Application, the Board approved Hydro One Brampton's request to dispose of its LRAMVA balances as at December 31, 2015, consisting of lost revenues from CDM programs in 2013, 2014 and 2015, and the related persistence through this period. The Board's Chapter 3 Filing Requirements requires distributors to provide a statement indicating that the distributor has relied on the most recent and appropriate final CDM evaluation report from the IESO in support of its lost revenue calculation and include a copy of this report.

Establishment of New Deferral and Variance Accounts

The Applicant has requested 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.

As described in Exhibit 2, Tab 3, Schedule 7 (PowerStream) and Exhibit 2, Tab 4, Schedule 7 (Enersource), the Metrolinx Regional Express Rail ("RER") Electrification is an infrastructure roll

[69] The IESO's Final Annual Verified Results for 2011 to 2014 and 2015 are filed as Attachments 12 and 13 for Horizon Utilities RZ; Attachments 29 and 30 for PowerStream; and Attachments 43 and 44 for Enersource RZ.

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.

- 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.

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.

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

Based on the foregoing, the Board's eligibility criteria for new deferral accounts are met:

Causation – Alectra Utilities can confirm that the forecasted underground and overhead capital expenditures required to support the Metrolinx Crossings Remediation Project are not included in the Enersource RZ DSP and no previous recovery has been sought or approved by the Board for this expenditure.

Materiality – At the timing of filing, a final project schedule outlining the crossings to be remediated in 2018 and which are in conflict with Metrolinx's OCS system for the GO electrification has not been provided. The existing Metrolinx Crossing Agreements specify that the utility is solely responsible for the relocation costs for its distribution system assets. Based on Alectra Utilities' experience with railway crossings, it is expected that the relocation of assets to accommodate GO electrification will be substantially higher than its materiality threshold.

Prudence – Alectra Utilities is obligated to remove or relocate certain parts of its distribution system in the vicinity of the rail lines. The Metrolinx Crossing Agreement provides that "should it become necessary or expedient for the purposes of repair or improvement of the railway line that the Works be temporarily removed or relocated, the Applicant shall upon request of the Owner and at the sole cost of the Applicant forthwith remove or relocate the Works".

Alectra Utilities has filed at Attachment 40 to the pre-filed evidence a proposed accounting order for the Enersource RZ and at Attachment 27 to the pre-filed evidence a proposed accounting order for the PowerStream RZ. Each proposed accounting order includes a description of the mechanics of the account, examples of the general ledger entries and the proposed manner in which to dispose of the account. Certain aspects of the proposed accounting orders were updated in response to PRZ-Staff-27(c).

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?

As explained on p. 3 of Exhibit 2, Tab 1, Schedule 2 of the pre-filed evidence, Alectra Utilities was required under International Financial Reporting Standards ("IFRS") to implement a new capitalization policy in 2017 (following the consolidation) to conform capitalization policies for the Alectra Utilities predecessor rate zones to that of the identified acquirer, the former PowerStream Inc., as part of its merger transaction.

In Procedural Order No. 3, the Board rendered its decision on the final issues list for this proceeding. The Board 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 Board also made provision for the establishment of three new deferral accounts "to track the change in capitalization" for the Horizon, Enersource and Brampton RZs. The Board further,

1. asked Alectra Utilities for confirmation that the capitalization change had no impact on Horizon's 2016 earnings; and

2. invited parties to provide any comments "on the recording details" for the new accounts by December 7, 2017.

The Board concluded by expressly noting that "[t]he nature of any disposition of these accounts is not being determined at this time" and that submissions in this respect would be heard as part of final argument.

By letter dated December 7, 2017, Alectra Utilities confirmed that the change in capitalization policy had no impact on Horizon's 2016 earnings and no impact on the proper calculation of the Horizon RZ ESM. Alectra Utilities further indicated that it anticipated arguing that the accounts should be closed with any entries reversed.

To be directly responsive to the Procedural Order, Alectra Utilities further advised the Board that the capitalization related accounts should track the total net impact of all financial differences arising from the change to Alectra Utilities' capitalization policy across all three rate zones, which it then believed (and has now confirmed) would be much less than the amount referred to in the Order.

On December 20, 2017 the OEB issued its Decision and Partial Accounting Order (the "Accounting Order") providing the recording details for the new deferral accounts for the Horizon, Enersource and Brampton RZs:

- Account 1508, Sub-Account Impact of Post-merger Capitalization Policy Changes ERZ;

- Account 1508, Sub-Account Impact of Post-merger Capitalization Policy Changes BRZ;

- Account 1508, Sub-Account Impact of Post-merger Capitalization Policy Changes HRZ;[70]

The Accounting Order is a partial order in that it does not include details on how the accounts will be disposed. To ensure that all options with respect to disposition of these new accounts remain open, the Board did not establish an end date for these accounts. This is consistent with the Board's earlier procedural order in which the Board advised that disposition would be a matter for argument.

With respect to the accounting entries, the Board concluded that the three new accounts will be used to record the difference between the revenue requirement calculated using the pre-merger capitalization policies and the revenue requirement calculated with the new capitalization policy. The revenue requirement will be calculated each year based on actual costs for OM&A, depreciation expense, income tax or PILs, and return on capital (debt and equity). This approach will result in the actual financial consequences of the changes to the capitalization policy being recorded. To ensure that there is no double-counting of earnings for the Horizon rate zone, the Board concluded that it is important to ensure that the new accounts for the capitalization change and the ESM account are coordinated.

Background to Change

Like all merging utilities, Alectra Utilities was required to adopt a uniform capitalization policy on merger across all of its rate zones. IFRS 10 *Consolidated Financial Statements*, states that uniform accounting policies must be adopted for like transactions in a group of companies. Further, IFRS 3 Business Combinations prescribes that the accounting policies of the parties to the merger should align to the acquirer's policy. IFRS 3 provides guidance on identifying the acquirer by assessing the relative voting rights in the combined entity after the merger; the acquirer being the combining entity whose owners, as a group, receive the largest portion of voting rights in the combined entity.

[70] In the Accounting Order, the Board established February 1, 2017 as the effective date for the three new accounts and stated that the accounts will remain open until such time as the Board orders otherwise. The effective date was established on the basis that this is when the new capitalization policy was adopted for the newly formed Alectra Utilities. For the Brampton rate zone, the Board acknowledged that there will be no entry until March 1, 2017.

Of the predecessor companies that formed Alectra Utilities, PowerStream is considered to be the acquirer in accordance with IFRS 3 and IFRS 10. Consequently, Alectra Utilities was required to adopt the PowerStream capitalization policy across all of its rate zones.

The capitalization policy change was effective February 1, 2017 for the Horizon Utilities and Enersource RZs and March 1, 2017 for the Brampton RZ.[71] The change did not affect the fixed asset classes pre-merger nor was there a change in the opening balances. The change impacts in-service additions in 2017 and subsequent years. The actual impact will be based on the level of actual capital expenditures in the respective year. The impact of the change to the capitalization policy is projected to provide for more capitalization of costs for the Enersource and Horizon Utilities rate zones and less capitalization of costs for the Brampton rate zone.[72]

The capitalization change had no impact on the underlying economics at any of Alectra Utilities' rate zones. It was (and is) a non-cash event. The cost of replacing a pole line on January 31, 2017 did not change the next day – it stayed the same. What changed was the relative share of the work that could be capitalized, nothing more. Regardless of the classification of any particular expenditure, be it as operating or capital, the expenditure must still be made in cash which is matched by rate-revenue cash flows.

Capitalization Accounts Should be Closed and Entries Reversed

The Board's policy on when capitalization changes should be reflected in rates is clear – changes should be made in a rebasing application, and not earlier. Chapter 2 (Cost of Service) of the Filing Requirements states in Section 2.2.2.3: "the applicant must provide its capitalization policy, <u>including changes to that policy since its last rebasing application filed with the OEB</u>" [Emphasis added].

The Board's MAADs policy is equally clear – consolidating distributors "are permitted to defer rebasing for a period of up to ten years following the closing of a consolidation transaction in order

[71] Response to JT.Staff-7(a).

[72] As explained in response to JT.Staff-7(d), the increase in capitalized costs for the Enersource and Horizon Utilities RZs results in a corresponding reduction in OM&A expenditures and an increase in depreciation expense over the life of the underlying assets. For the Brampton RZ, the decrease in capitalized costs results in a corresponding increase in OM&A expenditures and a decrease in depreciation expense over the life of the underlying assets. The net impact is forecast to increase pre-tax net income for the Enersource and Horizon Utilities RZs, which will attract higher taxes paid to tax authorities but that are not reflected in base rates for these rate zones. The total impact must then be offset by the annual return on the cumulative capital that can only be added to rate base at the time of rebasing.

to realize anticipated efficiency gains from the transaction and retain achieved savings for a period of time to help offset the costs of the transaction."[73]

Taken together, the Board's policy is clear that, where a rebasing deferral period has been approved by the Board 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.

In the MAADs application, Alectra Utilities chose to defer rebasing for the full ten year permitted period and proposed an ESM for years six to ten. These choices were heavily opposed by intervenors. As noted by the Board in the MAADs Decision, intervenors argued that:

- *the selection of the 10 year deferred rebasing period is not appropriate and poses a threat of harm to customers*;
- *the proposed ten year rebasing period is not required to offset the costs of the transaction as the evidence in this case is that the transaction and integration costs will be recovered by the end of the year three of the consolidation*; and
- *the proposed ESM does not adequately benefit customers and results in a significant imbalance between the incentives provided to the shareholders and the protection provided to customers*. [74]

Ultimately, intervenors submitted a number of proposals for the Board's consideration including, "approving a deferral period of five years rather than 10 years, amend(ing) the ESM to provide for no deadband, require(ing) an ESM where savings are shared with customers earlier than year six, <u>reduc(ing) rates by an amount sufficient to share benefits over the first ten years</u>, and adjust(ing) the sharing of savings on a 75:25 ratepayer/shareholder basis" [Emphasis added].[75]

The Board rejected every one of the intervenor arguments and proposals. The Board applied its MAADs policy and held:

> *OEB finds that this transaction is within the range of transactions anticipated by the OEB's policy. The outcomes are aligned with the policy's objective of improving the efficiency of*

[73] MAADs Decision, EB-2016-0025, p. 16

[74] MAADs Decision, EB-2016-0025, p. 17

[75] MAADs Decision, EB-2016-0025, pp. 17-18

> *electricity distribution….The OEB finds that customers will be not be harmed and will likely benefit in the long term from the enduring benefits of scale enhancements of service delivery arising from this transaction. In view of the policy objectives of this incentive scheme, the OEB does not consider the particular outcomes related to potential earnings relative to the status quo to be unreasonable.*[76]

As set out above, the change to Alectra's capitalization policy came about entirely as a result of the merger. Under IFRS, Alectra was required to adopt a uniform capitalization policy across all of its rate zones. To the extent the capitalization change reflects a "benefit" (non-cash), that benefit is to the account of Alectra's shareholders, just as ratepayers are shielded from all merger related costs. As indicated in response to JT.Staff-7(d), the anticipated size of the benefit is relatively modest - a total average annual net impact across all rate zones of $2.6MM. Notably, if Enersource been considered to be the acquirer under the applicable accounting standards rather than PowerStream, the capitalization policy change would have resulted in a cost that ratepayers would not have had to bear during the rebasing deferral period.

Arguments against this result will no doubt be made by intervenors. Whether disguised as a claim for Z-Factor treatment or put more directly as a claim to make rates more "just and reasonable", intervenor submissions on the issues list make clear that they will be looking for some form of adjustment. If accepted, this would be tantamount to the recapture of the benefits/costs associated with the merger that are to accrue to shareholders under the Board's MAADs policy. Intervenors asked for this in the MAADs application. As the School Energy Coalition ("SEC") then put the matter, "of the various methods the Board could use to ensure that rates for LDC Co. are just and reasonable, the simplest and most effective approach is to reduce rates for all LDC Co. customers, effective January 1, 2017, by 3.6%".[77] Their claims were denied. Indeed, the only difference between their position then and now is the present focus on a single item – capitalization – rather than the entire spectrum of merger related benefits and costs.

In effect, intervenors seek to 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 Board approved 10

[76] MAADs Decision, EB-2016-0025, pp. 19

years rebasing deferral period. The Board should see these arguments for what they are – a backdoor attack on the MAADs Decision and the MAADs policy itself that should be rejected. No doubt this argument would not have been pursued by intervenors had the non-cash change resulted in an increase in operating expense for Alectra Utilities. Alectra Utilities submits that the non-cash implications of accounting policy changes within a rebasing deferral period should not be the subject of rate-making changes within the rebasing deferral period as this is consistent with the MAADs policy and the Board's decision in the MAADs Application.

All of which is respectfully submitted this 22nd day of December, 2017.

ALECTRA UTILITIES CORPORATION

By its counsel, Torys LLP

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Crawford Smith

APPENDIX A - KEY RATIONALE FOR ICM PROJECTS

PROJECT **(Category)** **(2018 Budget)**	**KEY RATIONALE**
BRAMPTON RZ	
Pleasant TS True-Up System Access $6.8MM	• This investment is contractually required under the terms of the Connection and Cost Recovery Agreement (“CCRA”) between Alectra Utilities and HONI for the construction of the Pleasant Transformer Stations (“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 ten-year true-up payment under the CCRA is due in 2018 and Alectra estimates a shortfall of revenue to HONI versus the forecasted demand used to calculate the capital contribution initially made. A request is therefore anticipated from HONI in 2018 for the amount of $6.8M, with the final amount and payment terms to be negotiated at that time. Alectra will be obligated under the CCRA to make the payment.
POWERSTREAM RZ	
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 27.6kV 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.
Station Switchgear Replacement - 8th Line MS323 System Renewal $1.39MM	• The 8th Line MS323 station serves approximately 2,700 customers. The low voltage switchgear includes four circuit breakers that have been assessed as being in poor condition, at a high risk of failure and no longer supported by the manufacturer. The switchgear needs to be brought to current standards with respect to arc-resistant construction to reduce risk of failure. Addressing this issue is expected to avoid 97,200 customer outage minutes per year, which would have otherwise affected 900 residential and commercial customers. • To achieve efficiencies and cost savings, the project will include ancillary work (including renewing power cables and terminations, cable duct banks, oil containment, communications and relay panels) required to bring the station to current standards and improve reliability. If carried out separately from the project, such ancillary work will result in higher costs due to the need to undertake construction and installation again at the substation. • 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 from approximately 12 weeks to 4 weeks. • The project is the most cost-effective option over the long term because it extends the useful life of the station, avoids costly reactive repairs and replacements, and minimizes lengthy customer interruptions.
Rear Lot Supply Remediation - Royal Orchard - North System Renewal $1.68MM	• The rear lot distribution system in the area of Royal Orchard – North serves ~168 customers. It 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. 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 (e.g., storage sheds, play areas, patio decks, house extensions) inhibits access and introduces safety risks. There are operational inefficiencies when working on rear lot systems as well. Most work must be performed without use of bucket trucks and

	modern hydraulic equipment; inspections and troubleshooting require access to multiple yards; and tree trimming must be performed more frequently. • The Royal Orchard – North area will be converted to front lot underground supply over a three-year period from 2018 to 2020. This is the most effective option to eliminate safety and accessibility concerns, replace deteriorating assets and improve reliability. Approximately 110,000 outage minutes can be avoided per year (not considering major event days) by converting this system to front lot underground supply.
Cable Replacement – (M49) - Steeles Ave and Fairway Heights Drive System Renewal $1.84MM	• This project involves replacing 3700 m of substandard underground primary cables. Cable and splice failures are the leading cause of outage minutes, accounting for 19% of SAIDI in 2016. In the project area, the underground primary cable is 35 years old, was assessed as being in poor condition and is at the end of its useful life. • The project area is also one of the 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. Approximate annual savings of $26,000 in operating and maintenance costs are estimated from station decommissioning; and $40,000 in avoided distribution line and transformer losses from conversion to 27.6kV. • The project is expected to result in 81,480 outage minutes avoided per year and lower transformer and distribution line power losses.
Cable Replacement – (V08) - Steeles Ave and New Westminster System Renewal	• This project involves replacing substandard underground primary cables. Cable and splice failures are the leading cause of outage minutes, accounting for 19% of SAIDI in 2016. The project will replace 16,205m of cable from 2018 to 2020 (i.e. approximately 5,402m per year). The underground primary cable in the project area supplies 1,090 customers. It 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

$2.64MM	times in the last four years, resulting in over 350,000 customer outage minutes. • The 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 for each phase of the project.
Circuit Breaker Replacement – Richmond Hill TS#1 System Renewal $1.19MM	• This project involves replacing the 6 existing circuit breakers at Richmond Hill TS#1 due to technology incompatibility; history of failures; and manufacturer support no longer being provided. The project also includes the procurement of one spare circuit breaker, bringing the total number of units to 7. • The most recent circuit breaker failure at Richmond Hill TS#1 involving this type of circuit breaker affected 15,500 customers, and took over two hours to fully restore service. Kinectrics has conducted forensic analysis of the past breaker failure and concluded that the transient recovery voltage rating of this breaker is inadequate. • The project is expected to improve reliability; reduce the likelihood of customer interruptions; and enable cost savings through equipment standardization (i.e. reduced requirement for spares given the move to a standard breaker type across the system).
Rebuild of 27.6kV Pole Line on Warden into 4 Circuits from 16th Ave to Major Mackenzie System Service $1.37MM	• This project involves replacement of the existing two feeder 27.6kV 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. • Known large commercial facilities coming online in 2018 will add 9.5MVA of new load using up all available capacity of the two current feeders. Beyond 2018, the 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 additional feeders in the north Markham area, Alectra Utilities estimates that it would be able to serve only 0.5MVA of the 9.5 MVA in new load coming online in 2018. • This project is the most effective way to address the short and long-term capacity requirements in the area. 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.
Mill St. MS835 Transformer Upgrade – Tottenham System Service $1.3MM	• This 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 the Mill St and Queen St area of Tottenham, are expected to add 1,300 new customers. This growth will result in an additional 2.7 MVA of peak load supplied by the 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.
Double Circuit 27.6kV Pole Line on 19th Ave between Leslie and Bayview System Service $1.2MM	• This 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 the North Leslie 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 and commercial developments on 19th Ave (starting in 2018). Therefore, new load in the North Leslie development area cannot be serviced unless feeders are installed to connect the new customers. • A secondary concern 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 the other end 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.
Double Circuit Existing 23M21 from Bayfield &	• This project involves extension of feeder 23M28 along the existing path of 23M21 from Bayfield St and Livingstone St to

Livingstone to Little Lake MS306 System Service $1.28MM	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 rebuild of the existing pole line along Livingstone St (from Bayfield St to Cundles Rd) and along Cundles Rd to Little Lake. Phase 1 of the work (Bayfield St to Livingstone MS located at St Vincent St and Livingstone St) is expected to be completed by the end of 2017 to coincide with construction of Livingstone MS, and Phase 2 (east of Livingstone MS to Little Lake MS) is expected to be completed by the end of 2018.
ENERSOURCE RZ	
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.
Glen Erin & Montevideo Subdivision Rebuild System Renewal	• This project involves renewal and replacement of early generation underground distribution cables and 8 padmount transformers in the Glen Erin and Montevideo 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

$1.96MM	and having an adverse impact on reliability. Since 2013, SAIDI and SAIFI in the Glen Erin and Montevideo 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 resulting optimized configuration would allow Alectra Utilities to reduce replacement cost. Moreover, the new cables will be installed in PVC ducts to make future replacement much less costly and to meet current standards for residential underground distribution.
Glen Erin & Battleford Subdivision Rebuild System Renewal $2.06MM	• This project involves renewing and replacing early generation underground distribution cables and 5 padmount transformers in the Glen Erin and Battleford area to update them to 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 impacting reliability. Since 2005, 17 underground cable failures have occurred in the Glen Erin and Battleford 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. As per the 2016 ACA results, the cables in this area were flagged to be in very poor condition and are 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 resulting optimized configuration allows for minimized replacement cost (i.e., by replacing the existing 11.5km system with 6.5km of new infrastructure).
Credit Woodlands & Wiltshire Subdivision Rebuild	• This project involves renewing the distribution system in this area by replacing cables that are beyond the end of their useful life and transformers (11 in total) showing signs of leaks or containing PCB. • The replacement of transformers is needed to address safety, environmental, reliability, financial and regulatory risks and the

System Renewal $1.55MM	replacement of cables is needed to address the reliability issues. The cables and transformers in the area are approximately 37 years old and as per the 2016 ACA results, this cable section was flagged to be in very poor condition and requires immediate replacement. • This project provides an opportunity to remove redundant cables that were originally installed to accommodate the build phases of the subdivision. The resulting optimized configuration allows for minimized replacement cost. The new cables will be installed in PVC ducts, making future replacements easier and less costly.
Tenth Line Main Feeder Subdivision Renewal System Renewal $1.14MM	• This project involves renewing and replacing the early generation underground feeder cables in the Tenth Line area. • According to the ACA, main feeder cables in the Tenth Line area are in very poor condition and require 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 resulting optimized configuration allows for minimized replacement cost. The new cables will be installed in PVC ducts, making future replacements easier and less costly.
Folkway & Erin Mills Main Feeder Subdivision Rebuild System Renewal $1.03MM	• This project involves renewing and replacing early generation underground feeder cables in the Folkway and Erin Mills area. • According to the ACA, the main feeder cables in the Folkway and Erin Mills area are in very poor condition and require 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 resulting optimized configuration allows for minimized replacement cost. The new cables will be installed in PVC ducts, making future replacements easier and less costly.

City Centre Drive Rebuild System Renewal $1.55MM	• This project involves replacing existing cables and civil infrastructure in the City Centre Drive 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 the City Centre Drive 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 resulting in a significant and prolonged outage to a large customer that is supplied by these cables.
Lake/John Area Overhead Rebuild System Renewal $0.93MM	• This project involves renewing the overhead system in the area south of Lakeshore Road W. between John Rd and Mississauga Rd to mitigate risks of pole fires due to porcelain insulators; worker and public safety concerns due to missing ground wiring and poles in poor conditions; and potential environmental contamination due to transformer oil leaks. • The 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 or containing PCB, 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.
Church St. Area Overhead Rebuild System Renewal $1.02MM	• This project involves renewing the overhead system in the area east of Queen St. along Church St. to mitigate risks of pole fires due to porcelain insulators; worker and public safety concerns due to missing ground wiring and poles in poor conditions; and potential environmental contamination due to transformer oil leaks. • The project involves 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 or that contain PCB. 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.
Transformer Replacement Project System Renewal $8.45MM	• This project involves replacement of 2,244 transformers that have been identified as showing signs of oils leaks or containing PCB in a well-planned and paced manner until 2021. It addresses the safety, environmental, reliability, financial and regulatory risks (particularly to avoid disruptive and costly environmental clean-up). • 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 inspections undertaken from 2013 to 2016, 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.
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 the Meadowvale Business Park Area, 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.

	• Secondarily, this project is driven by 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 temporary station, the existing equipment and configuration is outdated and aged, and experiences reliability issues associated with the cable egress, protection and station configuration.