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May 28, 2019

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

Dear Ms. Walli:

**Re: Alectra Utilities Corporation ("Alectra Utilities")**
**Incentive Regulation Mechanism ("IRM") Application for 2020 Electricity Distribution Rates and Charges**
**OEB File No. EB-2019-0018**

Alectra Utilities Corporation ("Alectra Utilities") hereby submits its electricity distribution rate ("EDR") application for approval of proposed distribution rates and other charges in the Brampton, Enersource, Guelph, Horizon Utilities and PowerStream Rate Zones effective January 1, 2020. The proposed 2020 rates are based on 2019 rates adjusted by the Ontario Energy Board's ("OEB") Price Cap Index Adjustment Mechanism formula. This application is being filed in accordance with the OEB's Filing Requirements for Electricity Distribution Rate Applications – Chapter 3 Incentive Rate-Setting Applications, updated July 12, 2018 (the "Chapter 3 Filing Requirements").

As part of this application, Alectra Utilities is filling its first five-year Distribution System Plan ("DSP") on an integrated basis for its entire service area. The consolidated DSP has been prepared in accordance with the OEB's Filing Requirements for Electricity Distribution Rate Applications – Chapter 5 Consolidated Distribution System Plan Filing Requirements, updated July 12, 2018.

Alectra Utilities is also requesting an approval for capital funding based on a rate-adjustment mechanism that reconciles the capital needs set out in the DSP with the capital-related revenue in rates, and associated 2020 to 2024 capital riders for each rate zone. Alectra Utilities refers to this mechanism as an "M-factor".

**Alectra Utilities Corporation**
2185 Derry Road West, Mississauga, ON L5N 7A6 | t 905 273 7425 alectrautilities.com

This application includes live versions of the following:

- IRM Models
- M-factor Model
- HRZ ESM Rate Rider Model
- HRZ ESM Table of Allocations
- LRAMVA Work Forms
- GA Work Forms
- 1595 Work Form
- RGCRP Models

The Chapter 3 Filing Requirements specify that distributors should confirm the accuracy of the billing determinants for pre-populated models. Alectra Utilities wishes to advise the OEB that at the time of this filing, OEB models for 2020 EDR Applications were not yet available. Alectra Utilities has used the 2019 OEB models for creating the models on which this application is based. Alectra Utilities has confirmed the accuracy of the billing determinants to the 2019 RRR, section 2.1.5.4, for each rate zone.

In order to assist the OEB, Alectra Utilities has created a Table of Concordance for the application and the DSP. This is included it in the application.

Please note that the application includes a small amount of information that Alectra Utilities considers to be confidential. The relevant information has been redacted and a request for confidential treatment of that redacted information will be filed under separate cover.

Alectra Utilities has filed an electronic version of this application via RESS and will be providing two paper copies with the OEB.

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

Yours truly,

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

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**Exhibit 1, Tab 1, Schedule 1**

**Exhibit List**

# EXHIBIT LIST

# Exhibit 1, Tab 2, Schedule 1

# Legal Application

# ONTARIO ENERGY BOARD

**IN THE MATTER OF** the *Ontario Energy 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, 2020.

## APPLICATION

1. Alectra Utilities Corporation (the "Applicant" or "Alectra Utilities"), is a corporation incorporated under the *Ontario Business Corporations Act*, and is licensed by the Ontario Energy Board (the "OEB") to own and operate electricity distribution facilities under licence number ED-2016-0360.

2. Alectra Utilities hereby applies to the OEB pursuant to section 78 of the *Ontario Energy Board Act, 1998*, as amended (the "OEB Act"), for orders approving:

    a. Electricity distribution rates and charges in the Horizon Utilities, Brampton, PowerStream, Enersource and Guelph Rate Zones ("RZs") effective January 1, 2020, based on 2019 rates adjusted by the OEB's Price Cap Index Adjustment Mechanism formula;

    b. Capital Funding based on a rate-adjustment mechanism, referred to as an "M-Factor", which reconciles the capital needs set out in Alectra Utilities' Distribution System Plan ("DSP"), which has been prepared on a consolidated basis for its entire service territory and included in this Application, with the capital-related revenue in rates, along with the associated 2020-2024 capital riders for each RZ, to be updated annually, if needed, as part of the Price Cap IR application;

    c. A symmetrical Capital Investment Variance Account ("CIVA") to capture capital funding in excess of the revenue requirement associated with Alectra Utilities' actual in-service additions, to be credited or debited to customers at the end of the five-year plan term of the DSP;

d. A symmetrical Externally Driven Capital Variance Account ("EDCVA") to capture differences between the revenue requirement associated with externally driven capital expenditures (related to regional transit projects and capital works required by road authorities) as forecasted in the DSP, and the actual revenue requirement for in-service additions associated with such projects in the same period;

e. A Customer Service Rules-related Lost Revenue Variance Account ("CSRLRVA") to record lost revenue and incremental capital costs resulting from changes to customer service rules, and future policy changes implemented by the OEB;

f. A Conservation and Demand Management Severance Deferral Account ("CDMSDA") to record severance costs resulting from the the termination of the Conservation First Framework and associated CDM activities;

g. The termination of certain deferral accounts established in its 2018 Electrcity Distribution Rate ("EDR") Application (EB-2017-0024) to track the change in capitalization policy for the Horizon Utilities, Enersource and Brampton RZs;

h. Alectra Utilities' Earnings Sharing Mechanism ("ESM") proposal for the 2022-2026 period;

i. Disposition of the 2017 and 2018 Horizon Utilities RZ ("ESM") results, having regard to the changes to the capitalization policy and the Board's findings in respect of item e, above;

j. The calculation of the 2017 and 2018 Horizon Utilities RZ capital additions for the purpose of calculating the 2017 and 2018 entry to the Capital Investment Variance Account;

k. Closure of the deferral account established in connection with the Specific Service Charges study, as contemplated in the Settlement Agreement for Horizon RZ from its Custom IR Application (EB-2014-0002);

l. Clearance of the balances recorded in Alectra Utilities' Group 1 deferral and variance accounts by means of class-specific rate riders effective January 1, 2020 to December 31, 2020;

m. Recovery/Refund of Renewable Generation Connection Rate Protection ("RGCRP") funding; and

n. Disposition of the balance in Alectra Utilities' Lost Revenue Adjustment Mechanism Variance Accounts ("LRAMVA").

3. This Application is prepared in accordance with the OEB's:

   a. *Filing Requirements for Electricity Distribution Rate Applications*, issued July 12, 2018 (the "Filing Requirements");

   b. *Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, dated October 18, 2012; and

   c. *Handbook for Utility Rate Applications*, dated October 13, 2016.

4. This Application is supported by pre-filed written evidence which may be amended from time to time. For the reasons set out in this Application, Alectra Utilities submits that the proposed distribution rates and other charges are just and reasonable.

**PROPOSED EFFECTIVE DATE**

5. Alectra Utilities requests that the OEB make its Final Rate Order effective January 1, 2020. If the OEB does not expect that the Final Rate Order will be issued by such date, the Applicant requests an Order declaring its current (i.e., 2019) distribution rates and charges to be effective on an interim basis as of January 1, 2020 and establishing an account to record and facilitate recovery of any differences between the interim rates and the actual rates from January 1, 2020 until the implementation date of the OEB's Decision and Order establishing final rates and charges.

**FORM OF HEARING REQUESTED**

6. Alectra Utilities requests that the IRM elements of this Application be heard by way of written hearing. Alectra Utilities requests that the remaining elements of the Application be heard by way of oral hearing.

**CONTACT INFORMATION**

7. Alectra Utilities requests that copies of all documents filed with the OEB by each party to this proceeding be served on the Applicant and the Applicant's counsel as follows:

   a. The Applicant:

      Indy J. Butany-DeSouza
      Vice-President, Regulatory Affairs
      Alectra Utilities Corporation
      2185 Derry Road West
      Mississauga, Ontario, L5N 7A6
      Tel: (905) 821-5727
      Email: indy.butany@alectrautilities.com

   b. The Applicant's Counsel:

      Charles Keizer
      Torys LLP
      79 Wellington St West,
      Toronto, Ontario, M5K 1N2
      Tel: (416) 865-7512
      Email: ckeizer@torys.com

Dated at Mississauga, Ontario this 28th day of May, 2019.

**ALECTRA UTILITIES CORPORATION**

Indy J. Butany-DeSouza, MBA

Vice-President, Regulatory Affairs

**Exhibit 1, Tab 2, Schedule 2**

**Certificate of the Evidence**

**CERTIFICATION OF THE EVIDENCE**

As Executive Vice-President and Chief Financial Officer of Alectra Inc., I certify that, to the best of my knowledge, the evidence filed in this Application is accurate and is consistent with Chapters One, Three and Five of the Ontario Energy Board's *Filing Requirements for Electricity Distribution Rate Applications* issued on July 12, 2018.

John G. Basilio, CPA, CA
Executive Vice-President and Chief Financial Officer

# Exhibit 1, Tab 3, Schedule 1

# Executive Overview

# EXECUTIVE OVERVIEW

This Executive Overview provides a high level summary of the structure and key aspects of this Application.

## Application Structure

Exhibit 2 sets out the evidence and relief requested that relate to Alectra Utilities as a whole, including a summary of the utility's 2020-2024 DSP and proposed capital funding mechanism. Exhibit 3 sets out the evidence in respect of the Applicant's individual rate zones, including 2020 Price Cap IR adjustments; deferral and variance account disposition; Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA"); Horizon Utilities Rate Zone ("HRZ") Earnings Sharing Mechanism ("ESM") and Capital Investment Variance Account ("CIVA"); and Renewable Generation Connection Rate Protection ("RGCRP"). Exhibit 4 contains of Alectra Utilities' 2020-2024 DSP. Exhibit 5 includes attachments in support of various aspects of the Application.

## The Applicant and its Distribution System

Alectra Utilities serves over one million customers across its seventeen communities. These communities are growing rapidly, with a population forecast to grow from 3.5 million in 2016 to approximately 4.1 million by 2026. This Application sets out the work that Alectra Utilities must undertake to adequately serve its customers in these growing communities over the 2020 to 2024 period. As directed by the OEB, this Application includes Alectra Utilities' first five-year DSP, prepared on a consolidated basis across its service territory.

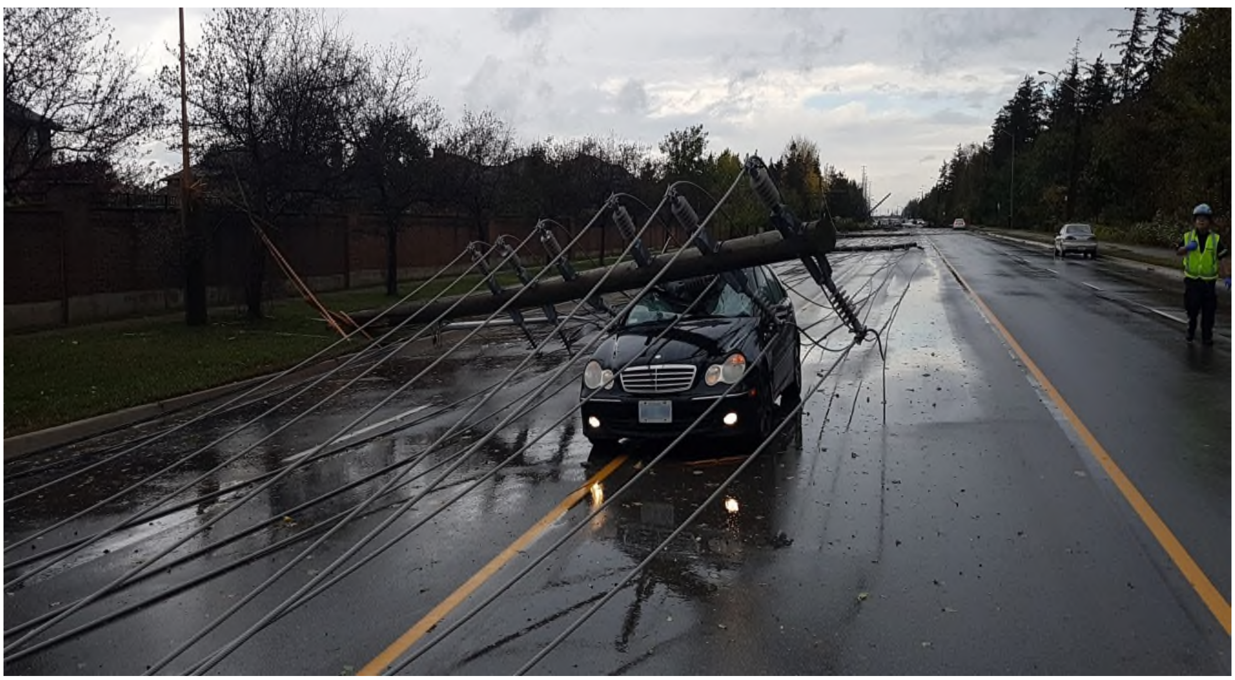
## The DSP

The 2020-2024 DSP is the first consolidated capital plan for Alectra Utilities. It represents the largest single planning exercise in its history. It is also a major milestone in Alectra Utilities' journey from five separate utilities to one single company, serving a single service area. The DSP is not a simple amalgamation of five distinct investment plans. Rather, it is a single, unified capital investment plan, built "*from the ground up*" to address the needs of the system as a whole in consideration of the identified priorities and preferences of Alectra Utilities' customers and a range of other planning considerations. The investments that are contemplated in the DSP are not based on the historical expenditures of the utilities that together have formed Alectra Utilities.

Rather, they were identified based on a data-driven asset management framework through which Alectra Utilities has prioritized projects based on the value they provide to the entire distribution system.

Alectra Utilities must balance multiple priorities over the 2020-2024 period of the DSP: maintaining reliability, providing appropriate service to growing communities, and doing so while keeping rates as low as possible. Customer reliability has been suffering due to various factors. Some of the largest challenges come from deteriorated equipment in its underground and overhead systems, and from the impacts of adverse weather events. These challenges are real, pose serious risks to the utility's reliability and, in some situations, pose potentially significant safety risks to the public and workers.

**Figure 1: Failure of Wood Pole on October 15, 2017**



At the same time, Alectra Utilities must invest to accommodate the growing communities it serves. During the 2020-2024 period, the utility expects to see considerable expansion into greenfield areas, as well as significant intensification and redevelopment in the downtown areas of several communities[1]. Alectra Utilities must invest now to ensure that sufficient capacity exists to connect these new and growing loads.

Alectra Utilities' plans are informed by multiple rounds of customer engagement, which occurred both before investment options were identified, and again once specific options and outcomes were defined.[2] Based on this engagement, Alectra Utilities has a clear understanding of the priorities of its customers: the utility must invest to maintain reliability and respond to adverse weather, and it must do so in a way that provides the best value to customers. Alectra Utilities has reflected these priorities and preferences throughout its planning processes, resulting in a plan that is designed to maintain reliability while deferring investments where appropriate to minimize the impact on customer bills.

The result of this extensive planning process is a five-year capital investment plan that meets customer expectations and addresses the challenges facing the system, but which takes a pragmatic approach, where possible, to moderate costs for customers.

**The M-factor**

While the DSP establishes a prioritized investment portfolio that is intended to provide optimal value, the cost of implementing it materially exceeds the capital funding available in Alectra Utilities' base rates. The base rates support average annual capital expenditures of approximately $236MM, whereas the DSP contemplates average annual capital expenditures of approximately $291MM. Therefore, with its base rates Alectra Utilities is left with $55MM of unfunded capital expenditures that it would not be able to execute in each year over the five-year DSP period. By the end of 2024, Alectra Utilities would otherwise be carrying the cost of $275MM in unfunded capital expenditures. This is in addition to the cost of unfunded capital from prior periods and other incremental costs (such as those from energy policy changes such as monthly billing and customer rule changes) that are not funded during Alectra Utilities' rebasing deferral period.

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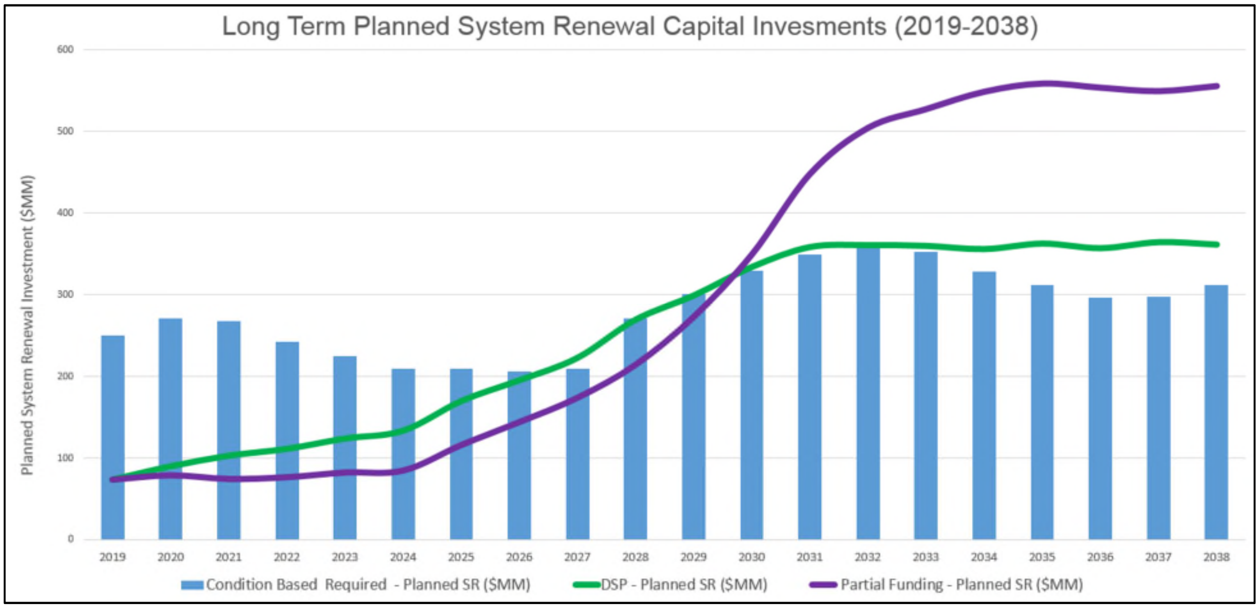
[1] See Appendix A12 – Lines Capacity of the DSP.

[2] See Sections 5.2.1 and 5.3.1 of the DSP.

In order to allow the critical work identified in the DSP to proceed, Alectra Utilities proposes a new mechanism to fund its planned capital investments for 2020-2024 period. Alectra Utilities calls this mechanism the "M-factor" or "MAADs-factor". Whereas the Incremental Capital Module ("ICM") may not be well-suited for sustained, multi-year capital needs such as those set out in the DSP, the M-factor would provide stable, predictable, funding for these critical investments across the DSP period. The M-factor is calculated in a manner that adheres as closely as possible to the OEB's ICM policy. Details of the M-factor calculation are set out in Exhibit 2, Tab 1, Schedule 3.

Without M-factor funding, critical investments would need to be deferred beyond 2024, resulting in: an increasingly deteriorated distribution system; decreasing reliability; increasing reactive expenditures; and greater renewal costs in the long term. If Alectra Utilities is unable to invest in system renewal at the level set out in the DSP, the result will be a growing population of deteriorated assets, leading to a "snowplow" of capital costs for future customers. As illustrated in Figure 2, the level of system renewal investment proposed in the DSP (i.e., the green line) is already significantly below the level dictated by the condition of the utility's assets. However, if the DSP is not fully funded (i.e., the purple line), the result will be a significant increase in renewal investments over the long term (assuming Alectra Utilities is able to secure resources necessary to execute such a plan). In the meantime, Alectra Utilities expects reliability to decline further, and inefficient reactive capital expenditures to continue to increase, without the level of investment set out in the DSP.

**Figure 2: Long-Term System Renewal Trends**




In order to ensure that customers pay no more than is necessary to fund prudent capital expenditures over the DSP period, Alectra Utilities proposes to establish a Capital Investment Variance Account to track the difference between the capital funding provided through M-factor riders and the utility's actual capital investments. This account will operate symmetrically, such that customers will be refunded for overall under-investment and any prudent spending above the level funded through M-factor riders will be recovered by Alectra Utilities. The total average annual bill impact from the proposed M-factor rate riders, range from 0.09% to 0.28% for a typical residential customer across all five rate zones.

## Rate Zone-Specific Requests

In this Application, Alectra Utilities also applies for rate zone-specific relief as set out in Exhibit 3, including: its calculation of the Horizon Utilities RZ ESM and CIVA amounts for 2017 and 2018; the Annual Price Cap IR adjustments; disposition of its Group 1 deferral and variance accounts; funding for RGCRP; and disposition of its 2017 LRAMVA balances.

**Proposed Effective Date of Rate Order**

A list of requested approvals is set out in the Legal Application at Exhibit 1, Tab 2, Schedule 1. Alectra Utilities proposes that the OEB make its Rate Order, together with the other relief sought in this Application, effective January 1, 2020. In addition, Alectra Utilities requests that the OEB declare each of the respective RZ's current (i.e., 2019) rates as interim effective January 1, 2020, as necessary, if the preceding approvals cannot be issued by the OEB in time to implement final rates, effective January 1, 2020. Alectra Utilities requests that, in the event that the OEB is unable to provide a Decision and Order in this Application for rates effective on January 1, 2020, the Board approve rate riders (including in respect of M-factor capital) that would provide for the recovery of foregone revenue for the period from January 1, 2020 to the implementation date of the 2020 Tariff of Rates and Charges.

**Conclusion**

The investments planned for the 2020-2024 period cannot wait. As demonstrated in detail in the DSP, the reliability of Alectra Utilities' distribution system is declining. The utility is increasingly required to conduct work on an emergency basis because the quality of service has deteriorated far below acceptable levels. Customers have clearly told Alectra Utilities that they expect it to maintain reliability and that they are willing to pay for the investments planned in the DSP to realize that outcome as set out in the Customer Engagement report filed as Appendix C of the DSP. If Alectra Utilities does not invest in system renewal at the level and pace set out in the DSP, it will quickly be overwhelmed by a growing backlog of deteriorated, unreliable, and, in some cases, potentially unsafe equipment.

In order to address these critical system needs, Alectra Utilities has proposed a mechanism that will provide the funding necessary to maintain reliability and satisfy customer expectations. As described in Exhibit 2, Tab 1, Schedule 3, the M-factor is an enhancement to the OEB's current rate making methodology, which is specific to the circumstances of a consolidated utility preparing and filing a consolidated DSP. The *Handbook to Electricity Distributor and Transmitter Consolidation* (the "MAADs Handbook") states that "having consolidated entities operate as one entity as soon as possible after the [MAADs] transaction is in the best interest of consumers."[3] Unlike other capital funding mechanisms available to utilities in a rebasing deferral period, the M-Factor will enable Alectra Utilities to plan and execute capital on a harmonized basis, while still providing it with "a reasonable opportunity to use savings to at least offset the costs of a MAADs transaction" as contemplated by the OEB's policy and approval of the merger that led to the creation of the utility.[4] However, without the funding provided by the M-factor, Alectra Utilities will be increasingly challenged to operate on that basis or deliver the outcomes that could otherwise result from the work set out in the DSP.

[3] Handbook to Electricity Distributor and Transmitter Consolidations, January 19, 2016, p. 13.

[4] OEB Report, *Rate-making Associated with Distributors Consolidation*, issued March 26, 2015, p. 5.

# Exhibit 1, Tab 4, Schedule 1

# Table of Concordance

# TABLE OF CONCORDANCE

**Chapter 3 Filing Requirements**

| | | Evidence Reference |
|---|---|---|
| | **Executive Overview** | Exhibit 1 Tab 3 Schedule 1 |
| | **Certification of the Evidence** | Exhibit 1 Tab 2 Schedule 2 |
| | | |
| **3.1.2** | **Components of the Application Filing** | |
| 1 | A manager's summary thoroughly documenting and explaining all rate adjustments requested | Exhibit 2 Tab 1 Schedule 1; and Exhibit 3, Tab 1, Schedule 1 |
| 2 | The contact information for the application | Exhibit 1 Tab 2 Schedule 1 |
| 3 | A completed rate generator model and supplementary work forms as applicable, both in Excel and Adobe PDF format | Exhibit 5, Tab 1, Schedule 1 |
| 4 | A PDF copy of the current tariff sheet | Exhibit 5, Tab 1, Schedule 1, Attachments 4-8 |
| 5 | Supporting documentation cited within the application (e.g. excerpts of relevant past decisions and/or settlement agreements; validated reporting and record-keeping requirements (RRR) data pre-populated in the rate generator model; other RRR data referred to in the application) | Exhibit 2 Tab 1 Schedule 1; Exhibit 3, Tab 1, Schedule 1; and Embedded in throughout the Application, as necessary |
| 6 | A statement as to who will be affected by the application | Exhibit 3, Tab 1, Schedule 1 |
| 7 | Confirmation of the Applicant's internet address for purposes of viewing the application and related documents | Exhibit 1 Tab 2 Schedule 1 |
| 8 | A statement confirming the accuracy of the billing determinants for pre-populated models | Exhibit 3, Tab 1, Schedule 7 |
| 9 | A text-searchable Adobe PDF format for all documents | Confirmed |
| | | |
| **3.2.1** | **Annual Adjustment Mechanism** | |
| 1 | Distributors shall use the 2019 rate-setting parameters as a placeholder until the stretch factor assignment and inflation factor for 2020 are issued | Exhibit 3, Tab 1, Schedule 4 |
| | | |
| **3.2.2** | **Revenue-to-Cost Ratio Adjustments** | |
| 1 | Adjust revenue to cost ratios | N/A |
| | | |
| **3.2.3** | **Rate Design for Residential Electricity Customers** | |
| 1 | Threshold Test: the monthly service charge does not exceed $4 per year; If $4 is exceeded, an extension of the transition period must be applied | Exhibit 3, Tab 1, Schedule 5 |
| 2 | Overall bill impact test: A utility shall evaluate the total bill impact for a residential customer at the distributor's 10th consumption percentile | Exhibit 3, Tab 1, Schedule 5 |

| | | |
|---|---|---|
| 3 | Distributors must provide a description of the method used to derive the 10th consumption percentile. The description should include a discussion regarding the nature of the data that was used (e.g. was the source data for all residential customers or a representative sample of residential customers). | Exhibit 3, Tab 1, Schedule 5 |
| 4 | If the total bill impact for customers at the 10th percentile is 10% or greater, a distributor must file a plan to mitigate the impact for the whole residential class or indicate why such a plan is not required | N/A |
| 5 | Where the evaluation of bill impacts indicates that rate mitigation is only required for the residential class, it is the OEB's expectation that distributors will propose mitigation strategies that target only the residential class | N/A |
| 6 | All new distribution-specific residential rate riders must be calculated based on a fully fixed rate design (e.g. ICM rate riders, shared tax savings, Z-factors) | Exhibit 5, Tab 1, Schedule 1, Attachment 3 |
| **3.2.4** | **Electricity Distribution Retail Transmission Service Rates** | |
| 1 | The IRM Model will reflect the most recent uniform transmission rates and sub-transmission rates approved by the OEB | Exhibit 3, Tab 1, Schedule 6 |
| | | |
| **3.2.5** | **Review and Disposition of Group 1 Deferral and Variance Account Balances** | |
| 1 | Calculation of the DVA disposition threshold (total claim/total kWh) to determine if the threshold of $0.001/kWh has been exceeded | Exhibit 3, Tab 1, Schedule 7 |
| 2 | A distributor must provide an explanation if the account balances on Tab 3. Continuity Schedule differ from the annual RRR filing | N/A |
| 3 | A statement confirming whether any adjustments to DVA account balances previously approved on a final basis have been included in the disposition claim | Exhibit 3, Tab 1, Schedule 7 |
| 4 | The EDDVAR Report states that the default disposition period to clear the Group 1 account balances by means of a rate rider should be one year. However, a distributor could propose a different disposition period to mitigate rate impacts or address any other applicable considerations, where appropriate | N/A |
| 5 | A distributor must not allocate any account balances in Account 1580 RSVA - Wholesale Market Services Charge, Account 1580 Variance WMS, Sub-Account CBR Class B, Account 1588 RSVA - Power, and Account 1589 RSVA - Global Adjustment to a wholesale market participant. | Exhibit 3, Tab 1, Schedule 7 |
| 6 | A distributor must ensure that rate riders are appropriately calculated for the following remaining charges that are still settled with a distributor. These include Account 1584 RSVA – Retail Transmission Network Charge, Account 1586 RSVA – Retail Transmission Connection Charge and Account 1595 – Disposition/Refund of Regulatory Balances. | Exhibit 3, Tab 1, Schedule 7 |
| 7 | Distributors must complete the GA Analysis Work form for each applicable fiscal year subsequent to the most recent year in which Accounts 1588 and 1589 were approved for disposition on a final basis by the OEB. | Exhibit 3, Tab 1, Schedule 7, as applicable |
| 8 | A distributor must provide a description of its settlement process with the IESO or host distributor. It must specify the GA rate it uses when billing its customers (1st estimate, 2nd estimate or actual) for each rate class, itemize its process for providing consumption estimates to the IESO, and describe the true-up process to reconcile estimates of RPP and non-RPP consumption once actuals are known. The description should detail the distributor`s method for estimating RPP and non-RPP consumption, as well as its treatment of embedded generation or any embedded distribution customers. The distributor's internal control tests, if any, in validating estimated and actual consumption figures used in its RPP settlement process and subsequent true-up adjustments | Exhibit 3, Tab 1, Schedule 8 |
| 9 | The application must include a certification that the distributor has robust processes and internal controls in place for the preparation, review, verification and oversight of the commodity account balances being disposed, consistent with the certification requirements in Chapter 1 of the filing requirements. | Exhibit 1 Tab 2 Schedule 2 |

| | | |
|---|---|---|
| **3.2.6** | **LRAM Variance Account** | |
| 1 | No peak demand (kW) savings from Demand Response (DR) programs should generally be included within the LRAMVA calculation. A distributor that wants to present empirical evidence to support DR savings in the LRAMVA can only do so as part of a cost of service or Custom IR application | Exhibit 3, Tab 1, Schedule 10 |
| 2 | Distributors must provide the LRAMVA work form in a working Microsoft Excel file to the OEB | Exhibit 5, Tab 1, Schedule 1, Attachments 36-39 |
| 3 | A statement identifying the year(s) of new lost revenues and prior year savings persistence claimed in the LRAMVA disposition. | Exhibit 3, Tab 1, Schedule 10 |
| 4 | A statement confirming that LRAMVA was based on verified savings results that are supported by the LDC's Final CDM Annual Report and Persistence Savings Report issued by the IESO. Both reports must be filed in excel format. A statement indicating that the distributor has relied on the most recent input assumptions available at the time of program evaluation. | Exhibit 3, Tab 1, Schedule 10 |
| 5 | A summary table showing the principle and carrying charges amounts by rate class and the resultant rate riders for each rate class. Projected carrying charges related to the disposition should be calculated in the LRAMVA Work form. | Exhibit 3, Tab 1, Schedule 10 |
| 6 | A statement confirming the period of rate recovery. Rationale must be provided for disposing the balance in the LRAMVA, if one or more rate classes do not generate significant rate riders. | Exhibit 3, Tab 1, Schedule 10 |
| 7 | Details for the forecast CDM savings included in the LRAMVA calculation including reference to the OEB's approval, or an explanation if there are no forecast CDM savings. | Exhibit 3, Tab 1, Schedule 10 |
| 8 | A statement confirming how the rate class allocations for actual CDM savings were determined by customer class and program each year. Documentation (e.g., tables supporting the rate class allocations) should be filed in Tab 3-a of the LRAMVA work form. | Exhibit 3, Tab 1, Schedule 10 |
| 9 | A statement confirming whether additional documentation or data was provided in support of projects that were not included in the LDC's Final CDM Annual Report (i.e., street lighting projects). Distributor billing data by project must be included in the work form in Tab 8, as applicable. For distributor street lighting project(s) which may have been completed in collaboration with local municipalities:<br>- Explain the methodology to calculate street lighting savings;<br>- Confirm whether the street lighting savings were calculated in accordance with OEB-approved load profiles for street lighting projects; and<br>- Confirm whether the street lighting project(s) received funding from the IESO and provide the appropriate net-to-gross assumption used to calculate street lighting savings. | Exhibit 3, Tab 1, Schedule 10 |
| | | |
| **3.2.7** | **Tax Changes** | |
| 1 | OEB policy prescribes a 50/50 sharing of impacts of legislated tax changes from distributors' tax rates embedded in its OEB approved base rate known at the time of application. These amounts will be refunded to or recovered from customers over a 12 month period | Exhibit 3, Tab 1, Schedule 11 |
| | | |
| **3.3.2** | **Incremental Capital Module - Filing Requirements** | See Capital Funding Mechanism (M-factor) - Exhibit 2, Tab 2, Schedule 3 |
| | | |
| **3.3.3** | **Treatment of costs for 'eligible investments' (i.e. GEA)** | |
| 1 | Distributors under Price Cap IR, who have yet to file a cost of service application containing a consolidated capital plan pursuant to Chapter 5, will continue to be able to request advance funding through a funding adder for renewable generation connection costs and smart grid development costs | Exhibit 3, Tab 1, Schedule 9 |

Distribution System Plan Chapter 5 Filing Requirements

| | | **Evidence Reference** |
|---|---|---|
| **5.2** | Where applicable, explanation for section headings other than Chapter 5 headings; cross reference table | N/A |
| **5.2.1** | Distribution System Plan Overview - key elements, sources of cost savings, period covered, vintage of information on investment drivers, changes to asset management process since last DSP filing, dependencies | Exhibit 4, Tab 1, Schedule 1, Section 5.2.1 |
| **5.2.2** | Coordinated Planning with 3rd parties - description of consultations<br>- deliverables of the Regional Planning Process, or status of deliverables<br>- IESO letter in relation to REG investments (Ch 5 p9) and Dx response letter | Exhibit 4, Tab 1, Schedule 1, Section 5.2.2 |
| **5.2.3** | Performance Measurement - identify and define methods and measures used to monitor DSP performance<br>- summary of performance and trends over historical period. Must include SAIFI and SAIDI for all interruptions and all interruptions excluding loss of supply<br>- explain how information has affected DSP | Exhibit 4, Tab 1, Schedule 1, Section 5.2.3 |
| **5.2.4** | Realized efficiencies due to smart meters<br>-documented capital and operating efficiencies realized as a result of the deployment and operationalization of smart meters and related technologies. Both qualitative and quantitative descriptions should be provided | Exhibit 4, Tab 1, Schedule 1, Section 5.2.4 |
| **5.3.1** | Asset Management Process Overview - description of AM objectives/corporate goals and how Dx ranks objectives for prioritizing investments | Exhibit 4, Tab 1, Schedule 1, Section 5.3.1 |
| **5.3.1** | Inputs/Outputs of the AM process and information flow for investments; flowchart recommended | Exhibit 4, Tab 1, Schedule 1, Section 5.3.1 |
| **5.3.2** | Overview of Assets Managed - description of service area (including evolution of features in forecast period affecting DSP),<br>- description of system configuration<br>- service profile and condition by asset type (tables and/or figures) - date data compiled<br>- assessment of degree the capacity of system assets is utilized | Exhibit 4, Tab 1, Schedule 1, Section 5.3.2 |
| **5.3.3** | Asset Lifecycle Optimization - description of asset lifecycle optimization policies and practices, including asset replacement and refurbishment, maintenance planning criteria and assumptions<br>- description of asset life cycle risk management policies and practices, assessment methods and approaches to mitigation | Exhibit 4, Tab 1, Schedule 1, Section 5.3.3 |
| **5.3.4** | System Capability Assessment for REG - REG applications > 10 kW, number and MW of REG connections for forecast period, capacity of Dx to connect REG, connection constraints<br>- REG applications > 10 kW, number and MW of REG connections for forecast period, capacity of Dx to connect REG, connection constraints | Exhibit 4, Tab 1, Schedule 1, Section 5.3.4 |

| | | |
|---|---|---|
| **5.4** | Capital Expenditure Plan Summary for significant projects and activities to be undertaken - capability to connect new load or Gx customers, total annual capex over forecast period by investment category, description of how AMP and Capex planning have affected capital expenditures for each category<br>- list, description and total capital cost of material capital expenditures sorted by category (table recommended)<br>- information related to Regional Planning Process (Needs Assessment Report, Regional Planning Status Letter, Regional Infrastructure Plan - as appropriate)<br>- description of customer engagement<br>- Dx expectations of system development over next 5 years | Exhibit 4, Tab 1, Schedule 1, Section 5.4.1 |
| **5.4.1** | Capital Expenditure Planning Process Overview - description of capex planning objectives/criteria/<br>assumptions, relationship with AM objectives, policy on consideration of non-distribution alternatives, processes used to identify projects in each investment category, customer feedback and impact on plan, method and criteria used to priorities REG investments | Exhibit 4, Tab 1, Schedule 1, Section 5.4.1 |
| **5.4.1.1** | Rate-Funded Activities to Defer Distribution Infrastructure<br>-CDM programs that target distributor-specific peak demand reductions to address a local constraint of the distribution system<br>-demand response programs to reduce peak demand in order to defer capital investment<br>-programs to improve the efficiency of the distribution system and reduce distribution losses<br>-energy storage programs whose primary purpose is to defer specific capital spending for the distribution system | Exhibit 4, Tab 1, Schedule 1, Section 5.3.4; Appendix A13 - Stations Capacity; AppendixA16 - Distributed Energy Resources |
| **5.4.2** | Capital Expenditure Summary by Investment Category - completed Table 2 of Ch 5 for historical and forecast period, explanation of markedly different variances plan vs actual, explanation of markedly different variances year over year<br>Table 2 of Ch 5 is provided in Excel format in Appendix 2-AB (must provide actual totals for historical years, as a minimum)<br>- Must also complete Chapter 2 Appendix 2-AA, along with explanations of variances by project or category, the proposed accounting treatments, a statement should be provided that there are no expenditures for non-distribution activities in the applicant's budg | Exhibit 4, Tab 1, Schedule 1, Section 5.4.2 |
| **5.4.3** | Justifying Capital Expenditures<br>-filings must enable OEB to assess whether and how a distributor's DSP delivers value to customers, including by controlling costs in relation to its proposed investments through appropriate optimization, prioritization, and pacing of capital-related expenditures<br>-distributors should also keep pace with technological changes and integrate cost-effective innovative projects and traditional planning needs such as load growth, asset condition and reliability | Exhibit 4, Tab 1, Schedule 1, Section 5.4.3 |
| **5.4.3.1** | Overall Plan - comparative expenditures by category over historical period, forecast impact of system investment on O&M, drivers of investments by category, information related to Dx system capability assessment | Exhibit 4, Tab 1, Schedule 1, Section 5.4.3.1 |
| **5.4.3.2** | Material Investments - For each project that meets materiality threshold set in Ch 2 p5<br>- general information - total capital, customer attachments, dates, risks, variances, REG investments<br>- evaluation criteria - may include: efficiency, customer value, reliability, etc.<br>- category specific requirements for each project - system access, system renewal, system service, general plant (as applicable) | Exhibit 4, Tab 1, Schedule 1, Section 5.4.3.2 |

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# Exhibit 1, Tab 5, Schedule 1

# Draft Issues List

# ISSUES LIST

## 1.0 GENERAL

1.1 Is the proposed effective date of January 1, 2020 appropriate?

## 2.0 CAPITAL PLAN AND FUNDING

2.1 Are the levels of proposed 2020-2024 capital expenditures arising from the distribution system plan appropriate, and are the rationale for planning, prioritizing and pacing choices appropriate and adequately explained?

2.2 Is the proposed capital funding rate adjustment mechanism, referred to as the "M-factor", appropriate?

2.3 Does the distribution system plan provide sufficient information to support the proposed M-factors?

2.4 Is Alectra Utilities' proposed Earnings Sharing Mechanism for the 2022-2026 period appropriate?

## 3.0 INCENTIVE RATE-SETTING MECHANISM (IRM) SCHEDULES AND MODELS

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

3.2 Is Alectra Utilities' proposed disposition of the 2017 and 2018 Horizon Utilities rate zone Earnings Sharing Mechanism results appropriate?

## 4.0 ACCOUNTING

4.1 Are Alectra Utilities' proposals for new deferral and variance accounts, the continuation of existing accounts and the termination of certain deferral accounts, appropriate?

4.2 Are Alectra Utilities' proposals for the balances in its existing deferral and variance accounts and their disposition appropriate?

4.3 Are the capitalization deferral accounts for each of the Brampton, Enersource and Horizon rate zones appropriate?

## Exhibit 2, Tab 1, Schedule 1

## Summary of Requests for Alectra Utilities as a Whole

# SUMMARY OF REQUESTS FOR ALECTRA UTILITIES

## Introduction

In this Application, Alectra Utilities Corporation ("Alectra Utilities") is filing its first five-year Distribution System Plan ("DSP") on an integrated basis for its entire service territory. In order to address the crucial and significant capital investment needs identified in the DSP, Alectra Utilities is seeking approval for capital funding based on a rate adjustment mechanism referred to herein as the "M-factor". The purpose of the M-factor is to bridge the gap, during Alectra Utilities' rebasing deferral period, between the level of investment funded through base rates and the level of investment that needs to be funded to address system priorities and outcomes consistent with customer needs and preferences, and which thereby enables Alectra Utilities to fully execute its DSP. Without the funding provided by the M-factor, Alectra Utilities will not be able to execute the DSP, nor will it be able to achieve the outcomes that its customers expect.

The M-factor also enhances regulatory efficiency since it avoids multiple and annual rate application proceedings to address Alectra Utilities' incremental capital needs. This outcome is consistent with OEB policy and recent provincial government legislation. For example, the OEB's Renewed Regulatory Framework ("RRF") states at page 8 that the rate regime must support efficient regulation and section 4.3(11) of the recently enacted *Fixing the Hydro Mess Act, 2019* requires that the chief commissioner "ensure the efficiency, timeliness and dependability of the hearing and determination of matters over which the Board has jurisdiction."

This Application also includes: requests for certain variance accounts related to the M-factor; Price Cap IR adjustments for rates in each of Alectra Utilities' Rate Zones ("RZs"); disposition of Group 1 deferral and variance accounts; reversal of previous capitalization policy conformance outcomes arising as a direct consequence of the 2017 Alectra merger; disposition and approval of Horizon Utilities RZ Earnings Sharing Mechanism ("ESMs"); as well as other relief.[5] This Exhibit 2 provides an overview of the Application's components that relate to Alectra Utilities as a whole, while Exhibit 3 relates to specific rate zone requests. Exhibit 2 is organized on the basis of each

[5] See complete list of requested relief in the Application, at Exhibit 1, Tab 2, Schedule 1.

of these areas of requested relief. Before doing so, the following section provides relevant context for the Application.

**Background**

Alectra Utilities, a wholly-owned subsidiary of Alectra Inc. ("Alectra"), is an Ontario corporation with its corporate head office in the City of Mississauga. Alectra Utilities carries on the business of distributing electricity within the communities of Mississauga, Hamilton, St. Catharines, Brampton, Alliston, Aurora, Barrie, Beeton, Bradford, Markham, Penetanguishene, Richmond Hill, Thornton, Tottenham, Vaughan, Guelph and Rockwood, pursuant to Ontario Energy Board ("OEB" or the "Board") Electricity Distributor Licence No. ED-2016-0360.

In April 2016, Enersource Hydro Mississauga Inc. ("Enersource"), Horizon Utilities Corporation ("Horizon Utilities"), and PowerStream Inc. ("PowerStream") (collectively the "predecessor Applicants") filed an application (the "MAADs Application"; EB-2016-0025) pursuant to the *Report of the Board: Rate-making Associated with Distributor Consolidations* and the *Handbook to Electricity Distributor and Transmitter Consolidation* (the "MAADs Handbook") seeking OEB approval to amalgamate to form Alectra, for Alectra to purchase and amalgamate with Hydro One Brampton Networks Inc. ("Hydro One Brampton") under section 86 of the *Ontario Energy Board Act 1998* (the "Act"), and for other related relief. In the MAADs Application, the predecessor Applicants selected a 10-year rebasing deferral period. On December 8, 2016, the OEB issued its Decision and Order granting the requested approvals in the MAADs Application, including the 10-year rebasing deferral period.

In March 2018, Alectra Utilities and Guelph Hydro Electric System Inc. ("GHESI") filed an application (the "Alectra/Guelph MAADs Application"; EB-2018-0014) seeking OEB-approval to amalgamate under section 86 of the Act. This application was granted and the amalgamation took effect January 1, 2019.

As identified in previous electricity distribution rate ("EDR") applications[6], Alectra Utilities expects that during the rebasing deferral period its rates will continue to be set on the basis of the individual RZs corresponding to each of its predecessor utilities. As indicated in the MAADs Handbook and

[6] Alectra Utilities' 2018 EDR Application (EB-2017-0024) and 2019 EDR Application (EB-2018-0016)

in the report entitled *Rate-making Associated with Distributors Consolidation*, issued July 23, 2007 (the “2007 Report”), as well as the updated report on the same topic issued by the OEB on March 26, 2015 (the “2015 Report”), the Alectra RZs will continue on their current rate plan terms until such terms expire. Under those plans, 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.

All of Alectra Utilities’ RZs will be under the Price Cap Incentive Rate-setting option for EDR from January 1, 2020 onward, until the Applicant’s next rebasing. Alectra Utilities developed models for IRM (the “IRM Model”) for use in this filing, based on the most recent OEB models available. As of the filing of this application, the 2020 OEB models for IRM applications were not yet available. Alectra Utilities will update this Application to reflect the 2020 IRM model when published by the OEB.

Both the MAADs Application and the Alectra/Guelph MAADs Application were based on the OEB’s policy that merging utilities would have both “a reasonable opportunity to use savings to at least offset the costs of a MAADs transaction”[7] and a mechanism to fund normal and expected capital investments.[8] As described in the M-factor and Capitalization Policy sections below, the first two rate-setting decisions for Alectra Utilities have frustrated those expectations. By providing stable base rates over the deferred rebasing period, the MAADs policy reduced the risk posed by mergers, and allowed utilities to manage within their own specific circumstances as they transition to a new, unified utility.[9]

Alectra Utilities has been unable to fund essential capital investments within the funding approved in its first two EDR applications.[10] The MAADs Application and the creation of Alectra Utilities was based on the availability of capital funding sufficient to maintain the distribution system and deliver performance at the level that customers expect. However, in the two annual rate-setting

[7] 2015 Report, p. 5

[8] 2015 Report , p. 9.

[9] 2015 Report , p. 6.

[10] EB-2017-0024 and EB-2018-0016.

applications that followed, the OEB determined that the ICM is unable to accommodate many of the investments needed to maintain Alectra Utilities' distribution system. In particular, ICM funding is not available for "typical annual capital programs" or smaller projects that do not on their own meet an undefined, secondary materiality threshold.[11] The cumulative cost for these types of necessary investments is significant, and the lack of funding for such work through rates is having a material impact on Alectra Utilities' distribution system.

The OEB's decision in EB-2017-0024 to reduce Alectra Utilities' revenue as a result of its adoption of a common capitalization policy has similarly frustrated Alectra Utilities' expectations for the rebasing deferral period. As set out in detail below in the section entitled "Reconsideration of Capitalization Policy Treatment," the OEB's decision to capture the impact of this accounting policy conformance has effectively turned a non-cash event with no economic value (the adoption of a capitalization policy) into a negative cash impact for the utility (reducing revenues despite there being no change to the utility's costs) and a positive impact for customers to the extent of potentially lower rates which, ironically, reduce cash flows necessary to support customer-based investment. This decision directly reduced the funding available for distribution-related activities, effectively rebasing this isolated aspect of the revenue requirement.

[11] EB-2017-0024, Decision and Order, April 6, 2018, p. 30.

# Exhibit 2, Tab 1, Schedule 2

# Consolidated DSP

## CONSOLIDATED DSP

Alectra Utilities is filing its first five-year DSP on an integrated basis for its entire service area, for the OEB's review. The MAADs Handbook encourages consolidating entities to operate as one as soon as possible. In the MAADs Application, Alectra Utilities indicated that it would file a consolidated five-year DSP in 2019. This was accepted by the OEB in the MAADs Decision. Further, in its Decision on Alectra Utilities' 2018 EDR Application (EB-2017-0024), the OEB confirmed the importance of a consolidated DSP, and the relationship between capital planning and funding. In the 2018 Application Decision, the OEB stated that it *"requires Alectra Utilities to file a consolidated DSP as a filing requirement with any ICM application requesting rate changes for 2020 rates and beyond".*[12] The consolidated DSP has been prepared in accordance with the OEB's *Filing Requirements for Electricity Distribution Rate Applications – Chapter 5 Consolidated Distribution System Plan Filing Requirements, updated July 12, 2018* (the "Chapter 5 Filing Requirements").

### Overview of the DSP

The DSP, which is included in Exhibit 4, Tab 1, Schedule 1, provides a comprehensive and detailed description of Alectra Utilities' capital investment plans for its distribution system over the 2020 to 2024 planning period. While the predecessor capital plans were appropriate for those utilities, the DSP is based on the needs of the entire Alectra Utilities distribution system, and its operation as a single utility. The DSP supports the effective and efficient planning of capital expenditures across Alectra Utilities' entire service area. As such, the DSP is not based on historical capital budgets of the predecessor utilities, rather it was developed from identified investment needs using a common and uniform Asset Management Framework. It is based on the priorities and preferences of all Alectra Utilities customers, as identified through multiple rounds of customer engagement. In particular, the DSP focuses on prioritizing prudent investments, in accordance with customer preferences so as to maintain overall reliability and address the adverse reliability impacts associated with extreme weather events.

[12] EB-2017-0024, Decision and Order, April 6, 2018, p. 2.

Alectra Utilities' investment plans are the outcome of its extensive business planning efforts, which have been informed by coordinated planning with third parties, formal and informal customer engagement, and the implementation of a robust, harmonized asset management framework, which is summarized below and described in detail in Section 5.3.1 of the DSP. The DSP describes these efforts in significant detail, to demonstrate how Alectra Utilities has aligned its asset management and investment planning processes and intended outcomes with the principles and expectations articulated by the OEB, as well as with its customer needs, priorities and preferences, and the corporate objectives established by its executive.

The following sections summarize: i) the outcomes that Alectra Utilities expects the DSP to achieve; ii) the role of customer input in informing the DSP; and iii) the new Asset Management framework that Alectra Utilities has implemented and upon which the DSP is based.

**Outcomes of the DSP**

The DSP addresses each of the performance outcomes identified by the OEB's *Handbook for Utility Rate Applications*,[13] with a focus on addressing the top priorities identified through engagement with the utility's customers. The priorities of Alectra Utilities' customers are that the company should maintain overall reliability and mitigate the impacts of extreme weather on service reliability, while ensuring that distribution rates are reasonable.

Alectra Utilities' distribution system has experienced declining reliability over the five-year period from 2014 to 2018. Over this period, the duration of outages has increased by an annual average rate of 16%, and the frequency of outages has increased by an annual average rate of 6%.[14] Defective equipment accounts for 45% of controllable outages in Alectra Utilities' system.[15] The majority of those outages are caused by failing cable; cable accessories and switching equipment. Accordingly, the largest category of capital expenditure planned in the DSP is for the renewal of deteriorated assets, with a particular focus on remediating and replacing deteriorated

[13] The performance outcomes are: Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance.

[14] Detailed information on the reliability trends of the distribution system are provided in Section 5.2.3 of this DSP.

[15] Exhibit 4, Tab 1, Schedule 1, DSP, Appendix A10 - Underground Asset Renewal.

underground equipment. This is because deteriorated underground equipment has been identified as the most significant contributor to Alectra Utilities' declining overall reliability and performance, as described below.

Alectra Utilities plans to focus investments on five priority areas during the 2020-2024 period:

1) **Preventing further decline in reliability due to deteriorating underground assets:** Alectra Utilities has experienced declining levels of reliability, both in terms of frequency and duration of outages, which are unacceptable to the company and its customers. The leading cause of this trend is defective equipment; specifically, failures of underground direct-buried cable and cable accessories. Mitigating such reliability and customer impacts through the renewal of deteriorated underground systems is a key focus for this DSP and represents approximately 25% of the capital expenditure plan.

   Alectra Utilities is entering a period of heightened capital asset renewal, as a large population of deteriorating assets are reaching their end-of-life. This capital asset bubble is especially pronounced in the underground cable population. These cables were installed in a period when Alectra Utilities' municipalities experienced significant growth (1960s to 1980s) and are now 40 to 60 years old. The cost of replacing these underground cables is far above the level that can be funded though Alectra Utilities' base rates. This investment cannot wait – not only is reliability declining due to cables that have already deteriorated, but there is an even larger renewal need on the horizon due to the significant proportion of cables installed between 1980 to 1990 that are starting to reach their end-of-life. Consequently, it is imperative that Alectra Utilities address the large population of deteriorated cable, as planned, over the DSP period.

2) **Enhancing the resilience of its overhead system to adverse weather events:** In order to address public and worker safety concerns, as well as reliability needs, Alectra Utilities plans to invest in replacing and remediating overhead assets that are deteriorated or otherwise prone to failure from adverse weather conditions. A particular focus will be on renewing deteriorated poles that have been identified through the utility's Asset Condition

Assessment[16] process as being in Poor or Very Poor condition, either through reinforcement or replacement. Reinforced and replacement poles are more resilient to ice and wind loading standards. Alectra Utilities plans to target a particular population of wood poles in circumstances where they carry four circuits.  This is a scenario that Alectra Utilities has found to be particularly susceptible to failure during storm and high wind events.

3) **Responding to anticipated needs in areas of new greenfield development and urban redevelopment and intensification:** Alectra Utilities must ensure that its system has sufficient capacity to connect new customers based on forecasted needs and to alleviate existing and anticipated capacity constraints.  The utility's planned capacity investments are primarily driven by: the pace and extent of urban development into greenfield areas; the intensification and redevelopment of downtown areas; and the need to address specific locations where adequate backup capacity is not available due to the configuration of existing supply lines.  Principal areas of greenfield expansion include the Markham Future Urban Areas, West Vaughan, Northwest Brampton, and Stoney Creek in Hamilton. Areas of intensification and redevelopment include downtown Mississauga, the Lakeshore Area of Mississauga, Brampton City Centre, Vaughan Metropolitan Centre, and several areas in Hamilton.

4) **Taking advantage of opportunities to establish additional linkages between legacy systems and balance loads across its entire service area so as to mitigate the need for system expansions:** Alectra Utilities plans to make targeted investments in establishing additional connections between adjacent legacy systems to assist it in balancing loads more effectively, thereby enabling it to defer more costly system expansions.

5) **Mitigating the need to rebuild or construct new stations by enhancing the use of monitoring technologies, investing in environmental protection measures and strategically managing inventory on a consolidated basis:** Alectra Utilities plans to

[16] Exhibit 4, Tab 1, Schedule 1, DSP, Appendix D – 2018 Asset Condition Assessment.

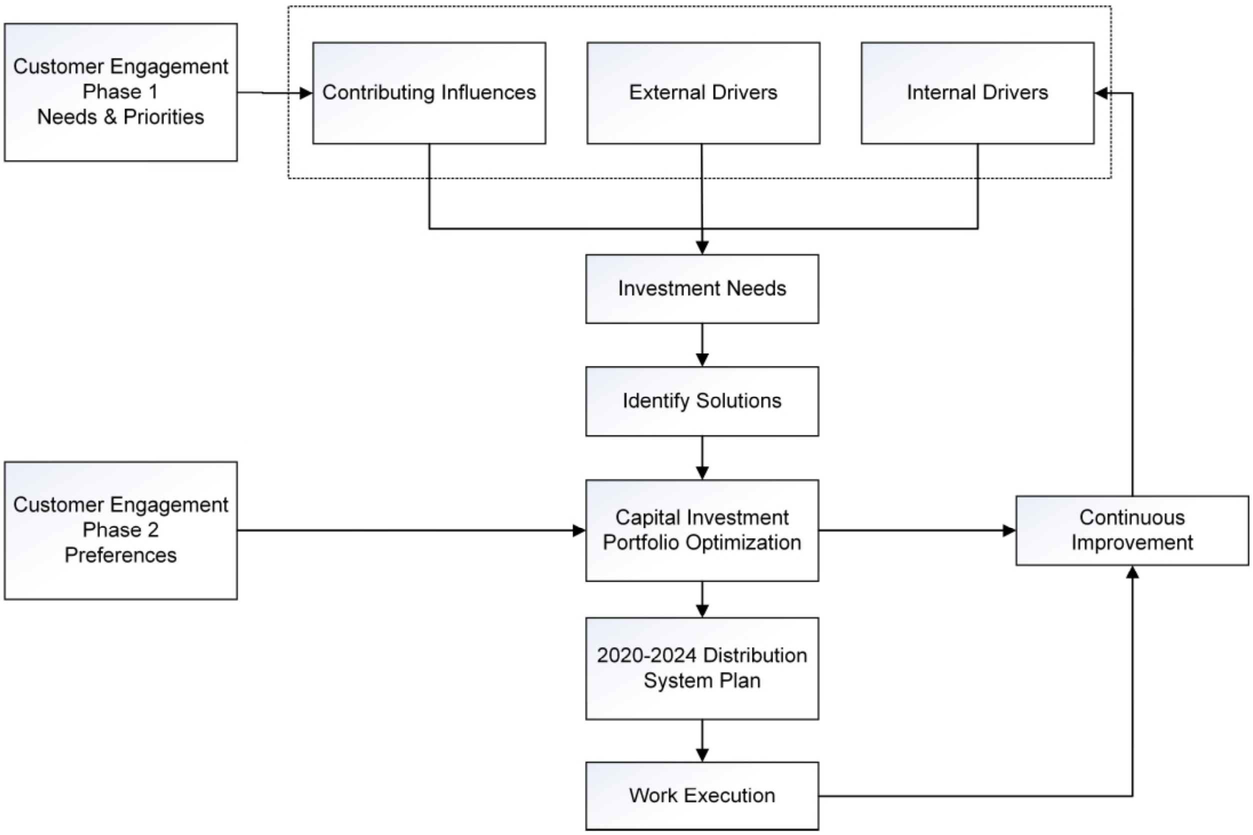
focus investment on renewing key equipment that is associated with controlling, monitoring and protecting core system assets. Much of this equipment is deteriorated and obsolete, which adversely affects reliability. In addition, investments in monitoring equipment, along with investments in oil spill containment, will give rise to significant capital savings by enabling the company to defer station renewal investments that would otherwise be needed.

**Asset Management Framework**

Alectra Utilities' Asset Management Framework is the foundation of the DSP, and serves as the basis for all capital investments. Asset Management decision-making is focused on balancing asset performance with the long-term value of investments. Alectra Utilities strives to maintain the lowest possible long-term cost of asset ownership, while considering customer needs and preferences and adhering to electrical system design requirements and standards, construction codes and prescribed asset and manufacturer specifications.

Alectra Utilities' Asset Management Framework evolved from leading asset management processes effectively applied at predecessor utilities and best industry practices. The result is a uniform and systematic Asset Management Process that allows Alectra Utilities to ensure that all system, customer and operational needs are considered for its expansive and diverse service territory, in alignment with identified customer preferences and priorities, regional planning needs, public policy objectives, and Alectra Utilities' Corporate Objectives. The manner in which customer needs have been identified and considered within this process is addressed below. The Asset Management Process is depicted at a high level below, with details set out in Section 5.2.1 of the DSP.

**Figure 3 - Overview of Alectra Utilities Asset Management Process**




While the Asset Management Framework includes several important advancements for the utility, two particularly important elements are its use of project-level prioritization through the adoption of the CopperLeaf C55 system and its reliance on customer input at multiple stages, as follows.

**CopperLeaf C55**

In developing the Asset Management Framework, Alectra Utilities incorporated best practices from its predecessor utilities. Building on the experience and expertise of PowerStream, Alectra Utilities selected the CopperLeaf C55 system as the solution to provide it with a repository for all capital project business cases and to manage the entire investment portfolio for the company. The CopperLeaf C55 system provides a uniform approach for the analysis and verification of the company's numerous and diverse capital project needs. By implementing this industry-leading solution with proven multivariate capital investment optimization capability, Alectra Utilities has the ability to run multiple investment scenarios considering financial, risk and resource driven constraints while ensuring capital investments are aligned with customer preferences and priorities, the utility's objectives, and public policy goals. This results in a Capital Investment Portfolio that yields maximum value, is risk-informed, and incorporates financial and non-financial benefits and other attributes on a common scale across Alectra Utilities' entire service area.

**Customer Engagement**

Customer engagement plays a central role in Alectra Utilities' Asset Management Framework, where it serves as a key input at multiple stages of the process, and thereby serves as a key input to the resulting capital investment plan. At the earliest stages of the process, before the utility began assessing specific investment options, it considered the needs and priorities of its customers. These needs and priorities were identified from ongoing customer engagement activities carried out by the company, as well as through DSP-specific engagement.

With more than 32,000 customers fully completing an online workbook, the Alectra Utilities 2020-2024 DSP customer engagement is the largest consultation ever conducted in the Ontario electricity sector. An initial overview of the voluntary results was provided on April 29. Alectra Utilities was provided with a report of the representative and voluntary responses on May 9. An updated version with 198 additional business responses was provided on May 15. While the new numbers allowed for further depth of analysis, they did not result in any substantive changes in the results. A final addendum with the additional GS over 50kW completes in Brampton was provided on May 23.[17]

At a high level, the process of gathering customer input and using that input to inform the DSP is summarized in Figure 4, below:

[17] Exhibit 4, Tab 1, Schedule 1, DSP, Appendix C, Customer Engagement Overview

**Figure 4: Collection and Use of Customer Feedback in Asset Management Process**

### Assessing Customer Needs & Priorities

- In mid-2018, Alectra Utilities consulted customers to assess their views on their needs and the outcomes they want the utility to prioritize in the 2020-2024 period.
- Innovative Research reported that, despite price concerns, customers are generally willing to consider paying more to maintain a reliable system.

### Identifying Investments based on Customer Needs & Priorities

- Alectra Utilities evaluated each part of the utility's business and identified all of the projects that could provide meaningful benefits to customers
- At the first stage of preparing the DSP, Alectra Utilities instructed its planners to identify investments to address negative reliability trends
- Alectra Utilities' planners focused on identified areas and assets where customers' reliability has been poor or deteriorating
- Alectra Utilities used its best efforts to find the right balance between keeping rates down and the other outcomes that customers valued

### Assessing Customer Preferences Between Specific Options

- In the spring of 2019, once a set of key investment options was identified, Alectra Utilities engaged customers a second time to assess their preferences between specific options.
- In this second phase, Innovative Research reported that customers stongly preferred investments in infrastrcture that most directly impacted their service, specifically investments in system renewal and system service

### Preparing a Prioritized Capital Investment Plan Based on Customer Preferences

- To reflect customer preferences, Alectra Utilities deferred investments in DER Pilots, building of a new municipal station in Alliston, voltage conversion project, lines capacity project, several facilities projects and reduced scope replacement of smart meters.
- To reflect customer preferences and identified renewal needs, Alectra Utilities increased the pace of investment in Underground Asset Renewal
- Please see Section 5.2.1.5-D of the DSP for a summary of all adjustments made based on customer preferences

The first stage of the DSP-specific engagement involved identifying and assessing customer needs and priorities with assistance from Innovative Research Group Inc. ("Innovative Research"), an independent public opinion research firm. Alectra Utilities then created a preliminary portfolio of investments responsive to those needs and preferences, which formed the basis of its second phase of customer engagement. The objective of the second phase was to identify customers' preferences between specific investment options and outcomes. Customer input from the second phase of engagement was used in the capital investment optimization process to finalize the investment portfolio set out in the DSP.

In the 2018 phase of the DSP-specific customer engagement, Innovative Research assessed that customers want Alectra Utilities to maintain a reliable distribution system, even if that means some increase in their distribution rates. At the same time, customers have also said that the price of electricity is important. For residential customers, price is typically the first priority, whereas large customers tend to prioritize reliability above price. However, in all customer segments, reliability and price have consistently been the top two priorities. The top five customer priorities were:

1. Charging reasonable distribution rates;
2. Ensuring reliable electrical service;
3. Reducing/managing consumption;
4. Minimizing and mitigating environmental impacts; and
5. Public and Employee Safety.

For large use customers, Innovative Research identified that ensuring reliable supply is a higher priority than distribution rates. Moreover, in terms of reliable electrical service, Alectra Utilities' customers indicated that their top reliability priority was to reduce the overall number of outages. This was followed by the need to reduce the impact of outages due to adverse weather and the need to reduce the overall length of outages. Alectra Utilities' understanding of these priorities served as a critical input into its identification of investment needs.

Based on those priorities, Alectra Utilities developed a preliminary set of potential investments for the 2020-2024 period. Those investment options were the basis of the 2019 consultation, which focused on customer preferences as between specific investment options and outcomes, including the total rate impact of those options.

In the 2019 customer engagement process, Alectra Utilities received feedback from 32,407 customers, making this phase of engagement the largest customer consultation ever conducted in Ontario's electricity sector. In it, Alectra Utilities asked customers for their preferences on the following specific capital investment areas:

i. Specific Asset Renewal Investments (Cables, Poles, Transformers)
ii. Rear Lot Conversion Investments
iii. Voltage Conversion Investments
iv. Capacity Investment (Stations and Distribution Lines)
v. Control and Monitoring Equipment Investments
vi. Metering Investments to mitigate data security risks
vii. General Plant Investments
viii. Pilots to evaluate integration of emerging technology and enable customer choice

In order to facilitate meaningful and informed feedback, Innovative Research developed a comprehensive workbook to present the overall scope of the DSP and to provide customer context for the investment options. The workbook was designed to provide customers an opportunity to reconsider their answers on individual investment choices after reviewing the total rate impact of their initial choices.

In the 2019 phase of customer engagement, Alectra Utilities customers indicated that they are prepared to fund the level of investment recommended by the utility. On specific investment categories, customers across all rate classes strongly support investments in the infrastructure that directly provides service to customers. Customers also indicated a strong consensus in support of recommendations for investments that directly serve customers including investments in underground asset renewal, overhead system renewal, transformer replacement, monitoring and control equipment as well as converting rear lot services. Customers were divided in their support for investments in general plant, innovation projects and replacement of smart meters to reduce data security risks.

Alectra Utilities incorporated customer preferences into the DSP by adjusting the pace of investments and deferring certain projects. The overall impact of the adjustment based on customer preferences from the second round of customer engagement on the 2020-2024 Capital Investment Plan, as well as other adjustments, was a net reduction of $17.5MM. The specific investments that were deferred, modified, or accelerated in response to customer input are listed in Section 5.2.1.5-D of the DSP.

Details on the customer engagement process are set out in Sections 5.2.1, 5.3.1 and 5.4.1 of the DSP, and the impact that customer input had on specific investment categories is described in the respective capital narratives provided as appendices to Section 5.4.3 of the DSP.

## Exhibit 2, Tab 1, Schedule 3

## Capital Funding Mechanism

## CAPITAL FUNDING MECHANISM ("M-factor")

Alectra Utilities is requesting approval for capital funding based on a rate-adjustment mechanism that reconciles the capital needs set out in the DSP with the capital-related revenue in rates, and associated 2020 to 2024 capital riders for each RZ, as follows.

### Overview

Underlying the OEB MAADs Policy and Handbook is the notion that amalgamations are in the public interest because they lead to efficiencies and future rates that are lower than otherwise would occur with no amalgamation. The OEB has expressed that it is in the public interest to have amalgamated utilities operate as one as soon as possible:

> "The OEB remains of the view that having consolidating entities operate as one entity as soon as possible after the transaction is in the best interest of consumers." [Handbook, p. 13]

Having amalgamated in 2017, Alectra Utilities is in transition and moving from individual utilities to an integrated utility operating as one company both from an OM&A and capital planning basis.

Through the rebasing deferral period, there is an integration of operations to achieve efficiencies and OM&A savings, which is part of the underlying regulatory and policy rationale for consolidation and the deferred rebasing period of 10 years. The other key element of the transition from separate utilities to consolidated operations is capital planning integration. Alectra Utilities, as a newly formed company, has moved to integrate capital planning across its company and service territory, to use one planning platform and to allocate resources and personnel in the execution of the capital plan across the company.

Alectra Utilities is in the unique circumstance of being the first utility arising from a consolidation of multiple utilities to file a five-year DSP in the midst of its rebasing deferral period rather than at its conclusion, as required by the OEB in Alectra Utilities' 2019 EDR Application Decision.[18] This circumstance is unique not just because Alectra Utilities is the first utility to do so, but also because of the rate making implications of presenting such a plan during the rebasing deferral period. While the DSP is based on a system wide consideration of Alectra Utilities' capital investment

[18] Decision and Order, April 6, 2018, EB-2017-0024, p. 2.

needs, rates during the rebasing deferral period are set on an individual rate zone basis. Also, whereas typically a DSP is filed as part of a rebasing enabling capital needs to form part of the rebasing year and potentially the IRM years as part of a custom approach, these aspects are not readily apparent in the filing of a DSP in the midst of the rebasing deferral period. It is in this unique circumstance that Alectra Utilities has proposed the rate approach below in order to fund the five-year capital plan contemplated in its consolidated DSP.

In order to address the factors described above, and to reconcile the investments set out in its DSP with the funding available in rates, Alectra Utilities has developed a new capital funding mechanism for post-merger utilities, which it calls an "M-factor."

**The M-factor**

Consistent with the Chapter 5 Filing Requirements, Alectra Utilities' DSP considers customer needs, priorities and preferences, system reliability, capital expenditures and resource deployment on a system-wide basis. This is in contrast with the previous plans filed by the company and the predecessor utilities. For example, Alectra Utilities' filing in EB-2017-0024 included the Enersource RZ DSP as a stand-alone plan, based on the needs of that operating area and the historically invested capital in that region. By definition, such stand-alone planning cannot be the planning basis of a consolidated DSP.

The M-factor complements the objectives and the capital funding mechanisms that are contemplated by the OEB in the 2015 Report, specifically the availability of capital funding of normal, expected investments during the rebasing deferral period. The M-factor also offers an envelope of capital funding that is substantiated by a five-year DSP. The ICM does not provide the flexibility or the longer-term availability of funding needed to execute a DSP. The DSP in this application spans Alectra Utilities' entire service territory and was developed on that basis. Accordingly, the investments in the DSP must be reviewed as a whole; it would not be meaningful for the OEB to review them in "slices" based on the historical zones on which the IRM rates and ICM riders are set. The OEB's Advanced Capital Module ("ACM") does not address this because of the need for flexibility between years and within years to execute a comprehensive capital plan.

In addition, distributors may request ACM within the context of a cost of service application filing[19]; this is incongruent with Alectra Utilities' current circumstances.

The nature of the investments set out in the DSP has informed Alectra Utilities' request for capital funding in this Application. As identified above, Alectra Utilities consulted with customers in order to understand their needs and priorities. The five-year DSP was developed to be responsive to the views of Alectra Utilities' customers. Alectra Utilities assessed customers' preferences between specific capital investment options and incorporated that feedback into the final DSP. In order for Alectra Utilities to deliver the outcomes that customers expect from the DSP, Alectra Utilities requires the flexibility to potentially accelerate some projects from later to earlier years or defer projects or split new projects into segments. As a result, Alectra Utilities proposes a capital rider based on an "M-factor", as described below, in every year of the five year planning period to reflect the execution of the entire consolidated DSP.

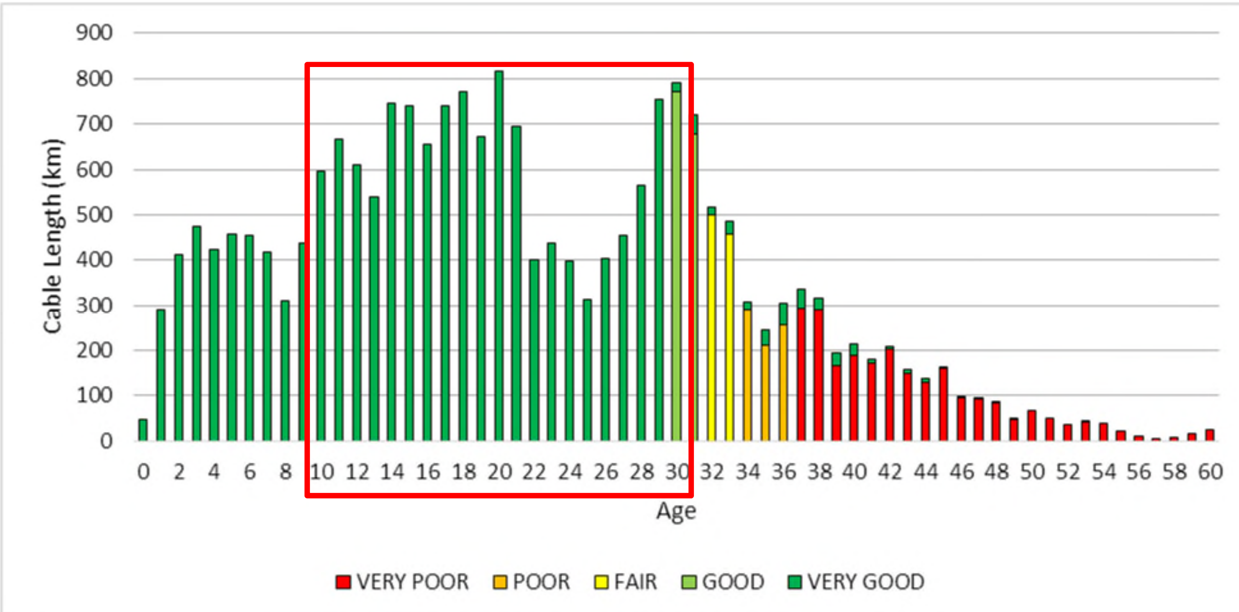
The purpose of the M-factor is to bridge the gap, during Alectra Utilities' rebasing deferral period, between the level of investment funded through base rates and the level of investment that needs to be funded to address system priorities and outcomes consistent with customer needs and preferences, and which thereby enables Alectra Utilities to fully execute its DSP. The utility's base rates will support an average annual capital expenditure of approximately $236MM during the DSP period. The DSP contemplates annual expenditures of approximately $291MM. Therefore, Alectra Utilities cannot execute $55MM of unfunded capital expenditures in each year, for a total of approximately $275MM of unfunded capital expenditures over the five-year DSP period. Without the funding provided by the M-factor, Alectra Utilities will not be able to execute the DSP and will not be able to achieve the outcomes that its customers expect.

If Alectra Utilities is unable to execute a capital plan at the level contemplated in the DSP, there will be significant, long-term negative consequences for the utility's distribution system and its customers. As summarized above and demonstrated in detail in the DSP, significant investments are needed to address declining reliability that is largely driven by deteriorated assets. The single largest example of this trend is the large population of direct-buried cable. As shown in Figure 5

[19] EB-2014-0219 *Report of the Board - New Policy Options for the Funding of Capital Investments: the Advanced Capital Module*, September 18, 2014, p.3

below, there is currently a large population of deteriorated underground in the system, but there is a much larger wave of cable that will deteriorate over the next twenty years (highlighted in the red box).

**Figure 5: XLPE Cable by Condition**




Failing underground cable has been a major driver of declining reliability for Alectra Utilities customers. The significant expenditures in Underground Asset Renewal during the DSP period are intended to maintain reliability by addressing cable that will be in very poor condition during the 2020-2024 period.[20]

While the potential backlog in underground cable is significant, it is only a component of a larger capital investment backlog that Alectra Utilities forecasts to develop if it is unable to execute the level of system of renewal investment set out in the DSP. If Alectra Utilities is unable to invest in system renewal at the level set out in the DSP, the result will be an increasing population of deteriorated assets, leading to a “snowplow” of capital costs for future customers. Figure 2 in the Executive Summary to the Application (Exhibit 1, Tab 1, Schedule 1) identifies Alectra Utilities’ proposed system renewal investment in the DSP, as compared to the significant increase in

[20] Planned Underground Asset Renewal investments are filed in DSP Appendix A10.

renewal investments required over the long term particularly if the proposed investment continues to go unfunded. The outcome is very likely a continued decline in reliability and an increase in expensive reactive capital expenditure.

The M-factor will provide Alectra Utilities with multi-year funding intended to address its planned capital expenditure for the next five years corresponding to its DSP, at a stable and predictable rate pursuant to a framework that adheres as closely as possible to OEB-policy and accords with past precedent. As elaborated in further detail in the section entitled Regulatory- and Cost-Efficiency, below, the M-Factor will also create significant efficiencies and avoid material costs for Alectra Utilities and the OEB over the five-year term. Further, it will allow Alectra Utilities to focus resources on executing the DSP and delivering the outcomes that customers expect.

Alectra Utilities has capital expenditure needs materially in excess of the level that which is presently funded in existing rates. As described above, the DSP identifies capital funding needs that exceed base rates by approximately $55MM per year. These spending levels are the product of the extensive asset management and investment planning processes described in the DSP, which align with the OEB's principles and expectations. In the OEB's *Renewed Regulatory Framework for Electricity Distributors: a Performance Based Approac*h (the "RRF") released on October 18, 2012, the OEB set out alternative forms of rate making "*to accommodate differences in the operations of distributors, some of which have capital programs that are expected to be significant.*" The OEB noted that the custom option in particular "*will be most appropriate for distributors with significant large multi-year…investment commitments that exceed historical levels*," whereas 4th Generation IR is more suitable for utilities with "some" incremental needs.

Custom IR is not a rate setting option available to Alectra Utilities during the rebasing deferral period. Further, the RRF framework was set several years prior to the update to the MAADs framework and related rate making in that context. However, the company's evolving capital needs are analogous to those distributors whose capital programs have been funded through Custom IR frameworks, accepted by the OEB. Like those other distributors, Alectra Utilities has significant, multi-year investment requirements supported by a five-year DSP. The fact that Alectra Utilities is operating during a rebasing deferral period does not vary this core fact. The OEB's MAADs policy recognizes that to promote consolidation distributors could elect a longer rebasing deferral period of up to 10 years and must also have access to capital funding that includes normal and expected capital investments.[21] Alectra Utilities' customers expect it to invest in capital during the rebasing deferral period, like other distributors. The 2015 Report does not exclude the possibility of the implementation of capital funding mechanisms other than ICM in order to permit prudent investments during the rebasing deferral period. Recognizing the unique circumstance presented by Alectra Utilities, the proposed M-factor is limited in scope to apply only to post-consolidation utilities that must execute a consolidated DSP during a rebasing deferral period.

Accordingly, Alectra Utilities applies for capital funding for all of its rate zones in the form of an annual rider calculated based on the M-factor. Alectra Utilities makes this request in accordance with:

- the OEB's *Filing Requirements for Electricity Distribution Rate Applications – Chapter 3 Incentive Rate-Setting Applications* issued July 12, 2018 ("Chapter 3 Filing Requirements");
- the MAADs Handbook;
- the OEB's *Handbook for Utility Rate Applications* (the "Rate Handbook"), dated October 13, 2016; and
- the Decisions and Orders of the OEB in Alectra Utilities' 2018 and 2019 EDR Applications (EB-2017-0024 and EB-2018-0016).

**Summary of the M-factor Approach**

Table 1 below summarizes the main elements of the M-factor and the purpose of each.

[21] EB-2014-0138 Report of the Board – Rate Making Associated with Distributor Consolidation, March 26, 2015, p.9.

**Table 1: M-factor Elements**

| M-Factor Element | Purpose | Comparison to ICM |
|---|---|---|
| **Materiality**<br><br>The M-factor includes a materiality threshold and 10% dead band, consistent with the OEB's ICM materiality threshold.<br><br>The M-Factor would not include a project-specific materiality threshold. | To ensure that the M-factor only provides funding for capital investments that are materially above the level funded in base rates.<br><br>As shown in Table 3, the maximum M-factor eligible capital is calculated on a five-year basis, spanning the entire DSP period. | Dead band is consistent with ICM methodology.<br><br>By calculating maximum M-factor eligible capital on a five-year basis, the M-factor reflects the material cost of recurring, moderate-scale projects across the longer timeframe of the deferred rebasing period. |
| **Flexibility**<br><br>Capital investments are funded on an envelope basis, allowing specific projects to be replaced, modified or shifted between years depending on system needs and priorities. | Flexibility is critical to allow Alectra Utilities to address evolving needs and priorities over the course of the DSP period. | ICM funding is typically tied to specific projects and years, making it poorly suited to a capital plan spanning multiple years and investments. |
| **Capital Investment Variance Account**<br><br>As set out further below in the Section titled "Proposed Variance Accounts", funding provided through the M-factor is subject to reconciliation through a symmetric variance account. | To ensure that any under-investment relative to the level of capital funded through the M-factor is refunded to customers, and any prudent spending above those levels will be recovered by the utility. | Consistent with the function of the ICM true-up process, where any over- or under-collection may be refunded or recovered from a distributor's ratepayers. |
| **Riders by Rate Zone**<br><br>Consistent with the OEB's decision in the MAADs Application, a rate rider will be established for each RZ, based on the investments planned in each of Alectra Utilities' operational areas. | Setting rate riders by rate zone is consistent with the MAADs Application. The MAADs Application confirmed that the rates will not be harmonized until rate differences are immaterial. | No change. |
| **Means Test**<br><br>The M-factor includes a Means Test consistent with the OEB's ICM policy. | The means test ensures that Alectra Utilities would not receive M-factor funding for a year in which its regulated return exceeds its deemed return on equity by 300 basis points. | No change. |

**Advantages of the M-factor Approach to Post-Merger Capital Funding**

The proposed M-factor is a well-reasoned mechanism for funding Alectra Utilities' capital expenditures in the 2020-2024 period in a manner that aligns to its corresponding DSP. In this regard, the M-factor has several advantages:

1. **Consistency with Capital Planning Basis**

The M-factor provides funding consistent with the consolidated basis on which Alectra Utilities' capital work is planned and on which the DSP has been prepared. The MAADs Handbook states that "having consolidated entities operate as one entity as soon as possible after the [MAADs] transaction is in the best interest of consumers."[22] Planning capital work on a consolidated basis is an important milestone in the utility's progress toward operating as a single entity. However, unless funding is available on a basis that is consistent with that consolidated investment plan, Alectra Utilities will be increasingly challenged to operate on that basis or deliver the outcomes that could otherwise result from the work set out in the DSP.

As described above and in Section 5.2.1 of the DSP, as of 2020, Alectra Utilities plans and prioritizes capital investments across the entirety of its service territory. The CopperLeaf C55 process prioritizes the projects that deliver the best value for Alectra Utilities' system, not for individual rate zones. The M-factor is consistent with this unified approach to investment planning. Rather than planning around eligibility for funding based on the historic investments of utilities that no longer exist, the M-factor would allow Alectra Utilities to invest in the equipment that delivers the best value for its customers, as a whole.

Under the MAADs policy, the default capital funding mechanism for post-merger utilities is the ICM. However, the OEB's prior decisions on Alectra Utilities' ICM requests have confirmed that the ICM is not able to accommodate many of the investments that Alectra Utilities must make during the DSP period. In its Decision and Order on Alectra Utilities' first ICM application (EB-2017-0024), the OEB found as follows:

> The OEB agrees that it is important for a distributor to have programs to address aging infrastructure to ensure assets are replaced on a paced and prioritized schedule. Nevertheless, this application is about whether incremental funding for capital will be provided during the IRM term. ICM funding is not available for

[22] Handbook to Electricity Distributor and Transmitter Consolidations, January 19, 2016, p. 13.

> typical annual capital programs. It is also not available for projects that are not significant to the operations of the distributor. Where the OEB has not approved a project for incremental funding, this should not be interpreted as the OEB saying that it is not prudent to complete the project.[23]

Over the five-year term of the DSP, Alectra Utilities plans to invest approximately $768MM in System Renewal. These investments are needed to be responsive to customer expectations that Alectra Utilities maintain the reliability of its system. The DSP provides detailed evidence on the prudence of the planned investments, including the need to execute them over the 2020 to 2024 period, in order to prevent reliability from declining further. These investments cannot be funded under the current ICM. The funding deficiency is not sustainable over time and is to the detriment of Alectra Utilities' customers.

In recent years, Alectra Utilities has been required to defer a significant amount of System Renewal investments to accommodate other mandatory expenditures. In particular, the utility has been required to defer renewal investments to accommodate large System Access projects. In 2015, System Access investments comprised 18% of the overall capital investments made by the company's predecessor utilities. This increased to 30% as of 2019 as a result of significant investments required in road authority projects. Decreasing reliability in that same period is due in part to the deferral of renewal investments. The M-factor will provide Alectra Utilities with the flexible funding basis necessary to execute both mandatory work and critical system renewal during the 2020 to 2024 period. The M-factor will allow Alectra Utilities to renew the assets that are leading to declining reliability, safety and other performance issues, while continuing to provide the utility with a reasonable opportunity to realize the synergies that underpinned its creation.

### 2. Regulatory- and Cost-Efficiency

Funding capital investments through the M-factor creates significant efficiencies for the OEB and for the utility. By establishing a mechanism to fund prudent capital expenditures based on a DSP over a five-year period, annual incremental capital proceedings are avoided. There would be a cost saving and OEB resources could be redirected to address other matters before the Board. Without an M-factor, Alectra Utilities will need to continue to file significant applications with the

[23] EB-2017-0024, Decision and Order, April 6, 2018, p. 30.

OEB each year. The cost of these annual applications and the time they consume both in development and adjudication is substantial for Alectra Utilities and the regulator.

Table 2 below provides the cost of Alectra Utilities past two applications as well as the forecast costs of this application.

**Table 2 – Alectra Utilities Annual Rate Application Costs**

| Application Year | Costs $MM |
|---|---|
| 2018 EDR Application | $1.4 |
| 2019 EDR Application | $0.5 |
| 2020 EDR Application (forecasted) | $2.2 |
| **Total Application Costs** | **$4.1** |

A significant proportion of the past two ICM applications focused on different phases of the same projects. In effect, parties were required to re-litigate the same issues on the same projects, one year apart. The cost of filing and adjudicating these additional serial applications will be significant, without contributing additional value for customers or for the OEB. Over a five-year period, this approach could result in the OEB spending more time and resources on Alectra Utilities' recurring ICM applications than it would on a single Custom IR application for another utility.

The regulatory efficiency gains produced by the M-factor are also consistent with public policy. In particular, section 4.3(11) of the recently enacted *Fixing the Hydro Mess Act, 2019* requires that the chief commissioner "ensure the efficiency, timeliness and dependability of the hearing and determination of matters over which the Board has jurisdiction."

The M-factor would enable Alectra Utilities to focus its resources on delivering the outcomes that customers expect. The cost and resources required to prepare and support a rate-setting application are significant. By providing a reliable level of funding over a multi-year period and avoiding annual rate-setting applications, Alectra Utilities will be able to focus its resources on delivering the investments that customers need, and executing that work in an effective, cost-efficient manner.

### 3. Rate certainty

The M-factor would provide the benefit of rate-certainty over the 2020-2024 period. Customers would be aware of bill impacts over a five-year period. Commercial and industrial customers in particular would benefit from the ability to budget and plan their operations in a longer period of relative rate-certainty. Alectra Utilities would benefit from the ability to plan its capital work based on the optimal pacing of the investments, rather than the outcomes of a series of annual rate-setting applications.

**Objective of the M-factor Approach**

The objective of the M-factor is to provide Alectra Utilities with capital funding for prudent capital investments on a basis that is consistent with the capital-related revenue requirement associated with the 2020-2024 DSP in the same period. Accordingly, Alectra Utilities sought to develop a mechanism that satisfies three criteria:

1. Consistency with existing OEB policy;
2. Provides flexible funding for prudent capital investments across the DSP period; and
3. Protects customers from potential under-investment relative to funding in rates.

Each criterion is discussed below, followed by the proposed calculation of the M-factor.

**1. <u>Consistency with Existing OEB Policy</u>**

While the M-factor is a new proposal based on Alectra Utilities' specific circumstances, the utility's goal is that the M-factor should reflect and augment existing OEB rate-setting mechanisms to the greatest extent possible (while providing sufficient funding to enable the investments and outcomes in the DSP). In this regard, the utility proposes that (i) the M-factor riders be calculated based on the materiality threshold calculation (including the dead band) from the OEB's ICM methodology, and (ii) that the need for M-factor funding be assessed relative to the means test set out in the OEB's ICM policy. Both of these elements of the M-factor are described below.

***i. Materiality***

As described above, the annual nature of the ICM does not address the needs of Alectra Utilities' distribution system or its customers in the context of a five-year DSP. However, the ICM materiality threshold remains an appropriate method to calculate the level of capital funding that a utility should be expected to absorb within its funding from base rates outside of a rebasing application. Accordingly, Alectra Utilities proposes to adopt the materiality threshold in the M-factor to determine the level of funding that is provided by base rates, including a deadband of 10%. Alectra Utilities would only be eligible for funding through the M-factor to the extent that its capital expenditures in a given year fit within the total eligible capital envelope derived from the materiality threshold for that year (i.e., the difference between the total capital budget for the year and the materiality threshold calculation).

Accordingly, Alectra Utilities proposes that the M-factor materiality threshold be calculated as follows:[24]

$$\textit{Threshold Value} (\%) = 1 + [(\frac{RB}{d}) \times (g + PCI \times (1 + g))]) \times ((1 + g) \times (1 + PCI)^{n-} + 10\%$$

*RB = rate base from the distributor's last cost of service*

*d = depreciation from the distributor's last cost of service*

*g = growth calculated based on the percentage difference in distribution revenues between the most recent complete year and the distribution revenues from the most recent approved test year in a cost of service application*

*PCI = Price Cap Index (IPI-stretch factor) from the distributor's most recent Price Cap IR application as a placeholder for the initial application filing to be updated when new information becomes available*

*n = number of years since the last rebasing*

As the threshold value is anchored on each predecessor utility's last rebasing application, the materiality threshold for Alectra Utilities has been calculated as the sum of the threshold values for each predecessor utility.

The PCI of 1.2% is a placeholder to be updated with the OEB's approved PCI for 2020 when it is available. It is based on inflation of 1.50% less a productivity factor of 0.00% and a stretch factor of 0.30% as identified in Table 3 below.

The growth rates have been calculated in accordance with the ACM Report and are equal to the change in revenue based on each predecessor's last OEB approved billing determinants divided by 2018 actual billing determinants, using 2019 approved rates. The growth rate calculation is identified in Table 3 below.

[24] Consistent with the methodology set out in the *Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module* (EB-2014-0219) issued on September 18, 2014 ("the ACM Report").

Table 3 below summarizes the calculation of the threshold capital expenditure amount using the Board's formula approved in the ACM Report. The threshold capital expenditure value over the 2020 to 2024 DSP period is $1.182B

**Table 3 – Threshold Capital Expenditure Calculation ($MM)**

| Description | ERZ | BRZ | GRZ | PRZ | HRZ | ALECTRA |
|---|---|---|---|---|---|---|
| Inflation | 1.50% | 1.50% | 1.50% | 1.50% | 1.50% | 1.50% |
| Less: Productivity Factor | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| Less: Stretch Factor | 0.30% | 0.30% | 0.30% | 0.30% | 0.30% | 0.30% |
| Price Cap Index | 1.20% | 1.20% | 1.20% | 1.20% | 1.20% | 1.20% |
| | | | | | | |
| Growth Factor | -0.05% | 1.84% | 1.60% | 2.31% | 3.04% | |
| | | | | | | |
| Rebasing Year | 2013 | 2015 | 2016 | 2017 | 2019 | |
| # Years since rebasing | 7 | 5 | 4 | 3 | 1 | |
| Price Cap Index | 1.20% | 1.20% | 1.20% | 1.20% | 1.20% | |
| Growth Factor | -0.05% | 1.84% | 1.60% | 2.31% | 3.04% | |
| Dead Band | 10% | 10% | 10% | 10% | 10% | |
| Rate Base | $610.5 | $404.6 | $151.4 | $1,082.8 | $555.7 | $2,805.0 |
| Depreciation | $28.7 | $15.2 | $6.3 | $52.3 | $23.9 | $126.4 |
| **Threshold Capital Expenditure 2020** | $39.1 | $30.7 | $11.6 | $98.5 | $50.0 | **$230.0** |
| **Threshold Capital Expenditure 2021** | $39.2 | $31.2 | $11.7 | $100.0 | $51.1 | **$233.1** |
| **Threshold Capital Expenditure 2022** | $39.3 | $31.6 | $11.8 | $101.5 | $52.1 | **$236.3** |
| **Threshold Capital Expenditure 2023** | $39.4 | $32.1 | $12.0 | $103.0 | $53.2 | **$239.7** |
| **Threshold Capital Expenditure 2024** | $39.4 | $32.5 | $12.1 | $104.7 | $54.4 | **$243.1** |
| **Threshold Capital Expenditure 2020-2024** | **$196.3** | **$158.2** | **$59.2** | **$507.7** | **$260.9** | **$1,182.2** |

Table 4 below compares the 2020 to 2024 capital forecast for Alectra Utilities to the Threshold Capital Expenditure to calculate the maximum M-factor eligible capital of $274MM.

**Table 4 – M-factor Maximum Eligible Incremental Capital ($MM)**

| Eligible Incremental Capital | Capital Expenditures |
|---|---|
| 2020 - 2024 DSP Capital Forecast | $1,456.5 |
| Less: Materiality Threshold | $1,182.2 |
| **Maximum M-factor Eligible Capital** | **$274.3** |

Table 5 below presents the M-factor capital investments, after Customer Engagement, based on the priority needs of Alectra Utilities, as identified in the DSP. The second phase of the customer engagement process focused on projects where Alectra Utilities would be more likely be able to make changes in response to customer preferences. Specifically, the engagement focused on a subset of projects that offered greater potential for pacing adjustments in response to customer preferences, alongside some exceptional projects that are distinct from the utility's typical capital investment categories. Although all of the projects included in the asset management process are necessary and provide value, Alectra Utilities generally has a greater ability to control the pace of the projects included in the second phase of customer engagement.

The projects addressed in the second phase of customer engagement were the same projects on which Alectra Utilities proposes to calculate the M-factor. By aligning customer engagement with the proposed capital funding mechanism, any changes to the proposed expenditures in response to customer preferences would be directly captured by the M-factor and, ultimately, reflected in customer bill impacts. In effect, this approach allowed Alectra Utilities to direct customer attention investments with a greater potential to present meaningful “trade-offs” between outcomes that matter to customers.

**Table 5 – 2020 - 2024 M-factor Capital Projects by Investment Need ($MM)**

| DSP Priority Needs | 2020-2024 M-Factor Capital Expenditures |
|---|---|
| Enhancing the resilience of its overhead system to adverse weather events | $62.4 |
| Mitigating the need to rebuild or construct new stations by enhancing the use of monitoring technologies, investing in environmental protection measures and strategically managing inventory on a consolidated basis | $43.9 |
| Preventing further decline in reliability due to deteriorating underground assets | $35.2 |
| Responding to anticipated needs in areas of new greenfield development and urban redevelopment/intensification | $123.6 |
| **Total M-factor Capital Expenditure** | **$265.0** |

***ii. Need***

In addition to the materiality criteria, Alectra Utilities proposes that the M-factor include a Means Test consistent with the calculation defined in the ACM Report. Alectra Utilities must satisfy this Means Test in order to qualify for funding through the M-factor.

If Alectra Utilities’ regulated return, as calculated in its most recent calculation (Reporting and Record Keeping Requirements (“RRR”) 2.1.5.6), exceeds 300 basis points above the deemed return on equity (“ROE”) embedded in its rates, M-factor funding will not be available in that year.

Alectra Utilities filed its 2018 annual Reporting and Record Keeping Requirements ("RRRs") on April 30, 2019. RRR data for all measures were filed for Alectra Utilities, and not individually, by rate zone. The 2018 RRR filing excludes the Guelph RZ which became part of Alectra Utilities effective January 1, 2019. Alectra Utilities' 2018 ROE was calculated to be 7.66%, 128 basis points below a calculated ROE for Alectra of 8.94%. Alectra Utilities calculated a consolidated deemed ROE percentage using the weighted average of the OEB-approved rate base amounts for each rate zone, from the most recent OEB-approved rebasing application for each of the predecessor companies. Alectra Utilities' ROE calculation for 2018, filed in RRR 2.1.5.6, is filed as Attachment 1.

The 2018 ROE for Alectra Utilities' predecessor, Guelph Hydro, was calculated to be 8.18%, 101 basis points below its approved 2018 ROE of 9.19%. The ROE calculation for Guelph Hydro, included in RRR 2.1.5.6, is filed as Attachment 2.

Alectra Utilities, including in respect of its predecessor Guelph Hydro, therefore satisfies the Means Test for 2020.

**2. <u>Provides flexible funding for prudent capital investments</u>**

As set out above, Alectra Utilities 2020-2024 DSP is a single, harmonized plan comprised of a wide range of different investments. The DSP is not organized around RZs, nor is it driven by specific large projects. In order to effectively implement this plan, and achieve the outcomes that customers require and expect, Alectra Utilities must be able to execute all of the work in the DSP, while simultaneously accommodating changing circumstances that may require acceleration of some work and deferral of other work. Accordingly, the M-factor must be able to fund the range of capital work that comprises the DSP, not just a particular large project or subset of projects.

While the M-factor riders are calculated based on the specific investments contemplated by the DSP, they are not tied to those specific investments. Unlike other funding mechanisms during an IRM term, the M-factor provides an envelope of capital funding to fund prudent investments during the 2020-2024 period and is comparable in its approach to Custom IR treatment made in conjunction with a five year DSP.

### 3. Protects Customers from Under-Investment

Alectra Utilities understands that customers need to know that any additional capital funding provided in rates is, in fact, invested in the distribution system. Accordingly, Alectra Utilities proposes that the funding provided through M-factor riders be subject to reconciliation with actual capital investments during the DSP period. As set out below, at Exhibit 2, Tab 1, Schedule 4, the utility has proposed that a Capital Investment Variance Account ("CIVA") be established to track the difference between the capital funding provided through M-factor riders and the utility's actual capital investments during the term of the DSP. This account will operate symmetrically, such that customers will be refunded for overall under-investment and any prudent spending above the level funded through M-factor riders will be recovered by Alectra Utilities. Such a mechanism was previously implemented for the first time by an Alectra Utilities' predecessor, Horizon Utilities, with support from intervenors and the OEB. Further details on the CIVA are provided in the Proposed Variance Accounts section, below.

**Calculation of M-Factor Funding and Riders**

This section sets out Alectra Utilities' proposal for how the M-factor and resulting riders should be calculated during the 2020-2024 DSP period.

The cumulative 5-year capital revenue requirement associated with the M-factor funding request of $286,036,835 is $27,891,068. Table 6 below summarizes the M-factor capital revenue requirement for 2020 through 2024.

**Table 6 – M-factor Capital Revenue Requirement ($MM)**

| M-factor Revenue Requirement | 2020 | 2021 | 2022 | 2023 | 2024 | Total |
|---|---|---|---|---|---|---|
| Return on Rate base - Total | $3.2 | $2.6 | $3.2 | $3.0 | $3.9 | $15.8 |
| Amortization | $1.9 | $2.0 | $2.1 | $2.8 | $2.4 | $11.2 |
| Incremental Grossed Up PILs | ($0.4) | ($2.3) | ($1.3) | ($0.3) | ($0.9) | ($5.1) |
| **Total** | **$4.7** | **$2.3** | **$3.9** | **$5.6** | **$5.4** | **$21.8** |

Alectra Utilities has calculated capital revenue requirement by rate zone based on the projects to be completed in each of the service areas. In the MAADs Application, Alectra Utilities identified that rates will not be harmonized until rate differences are immaterial.

The Rate of Return has been calculated using the cost of capital parameters approved by the OEB in the predecessor utility's last rebasing application[25].

A full year of depreciation has been recovered which is consistent with the OEB's policy in 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. Similarly, PILs have been calculated using a full year of Capital Cost Allowance ("CCA").

The detailed calculation of M-factor capital revenue requirement is filed as Attachment 3.

**Rate Riders**

Alectra Utilities is seeking OEB approval for the M-factor rate riders identified in Attachment 3. The M-factor capital revenue requirement has been allocated to rate classes based on the current allocation of revenue using the current Revenue Proportions for each rate zone as identified in the M-factor Model, filed as Attachment 3. The M-factor capital revenue requirement for the residential class will be recovered via a fixed rate rider as directed by the OEB at p.8 of the Filing Requirements for Electricity Distribution Rate Applications – Chapter 3 Incentive Rate-Setting Applications, issued July 12, 2018 (the "Chapter 3 Filing Requirements). Rate riders for all other rate classes are based on the current fixed/variable revenue split identified in the M-factor Model. Tables 7 to 11 identify the M-factor rider, inclusive of HST, based on the average consumption and demand billing determinants for each rate zone.

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[25] The exception to this is the HRZ-related cost of capital parameters that were updated in 2019, per the Horizon Utilities Settlement Agreement (EB-2014-0002) and as approved by the OEB in the Decision and Order in Alectra Utilities 2019 EDR Application (EB-2018-0016)

## Table 7 – M-factor Capital Funding Rate Riders, Including HST - ERZ

| ERZ - M-factor Rate Rider Incl HST | Unit | kWh | kW | 2020 | 2021 | 2022 | 2023 | 2024 | Total |
|---|---|---|---|---|---|---|---|---|---|
| Residential | kWh | 750 | | $ 0.13 | $ 0.06 | $ 0.17 | $ 0.20 | $ 0.39 | $ 0.95 |
| General Service < 50 kW | kWh | 2,000 | | $ 0.37 | $ 0.17 | $ 0.50 | $ 0.59 | $ 1.15 | $ 2.77 |
| General Service 50 to 499 kW | kW | 100,000 | 230 | $ 6.53 | $ 3.01 | $ 8.83 | $ 10.48 | $ 20.38 | $ 49.23 |
| General Service 500 to 4999 kW | kW | 400,000 | 2,250 | $ 40.70 | $ 18.74 | $ 54.98 | $ 65.30 | $ 126.93 | $ 306.65 |
| Large Use | kW | 3,000,000 | 5,000 | $ 163.63 | $ 75.35 | $ 221.08 | $ 262.57 | $ 510.39 | $ 1,233.03 |
| Unmetered | kWh | 300 | | $ 0.08 | $ 0.04 | $ 0.11 | $ 0.13 | $ 0.25 | $ 0.60 |
| Street Lighting | kW | 33 | 0 | $ 0.02 | $ 0.01 | $ 0.02 | $ 0.02 | $ 0.05 | $ 0.12 |

## Table 8 – M-factor Capital Funding Rate Riders, Including HST – BRZ

| BRZ - M-factor Rate Rider Incl HST | Unit | kWh | kW | 2020 | 2021 | 2022 | 2023 | 2024 | Total |
|---|---|---|---|---|---|---|---|---|---|
| Residential | kWh | 750 | | $ 0.32 | $ 0.04 | $ 0.23 | $ 0.20 | $ 0.12 | $ 0.92 |
| General Service < 50 kW | kWh | 2,000 | | $ 0.80 | $ 0.11 | $ 0.56 | $ 0.50 | $ 0.30 | $ 2.26 |
| General Service 50 to 699 kW | kW | 182,500 | 500 | $ 22.58 | $ 3.02 | $ 15.88 | $ 14.16 | $ 8.46 | $ 64.10 |
| General Service 700 to 4999 kW | kW | 627,216 | 1,432 | $ 85.50 | $ 11.45 | $ 60.12 | $ 53.63 | $ 32.03 | $ 242.74 |
| Large Use | kW | 10,220,000 | 20,000 | $ 798.09 | $ 106.92 | $ 561.20 | $ 500.59 | $ 299.01 | $ 2,265.82 |
| Unmetered | kWh | 21,296 | | $ 6.17 | $ 0.83 | $ 4.34 | $ 3.87 | $ 2.31 | $ 17.53 |
| Street Lighting | kW | 2,787,508 | 7,922 | $ 1,336.07 | $ 178.99 | $ 939.50 | $ 838.03 | $ 500.57 | $ 3,793.17 |
| Embedded Distributor | kWh | 1,417,701 | 4,000 | $ 60.80 | $ 8.15 | $ 42.75 | $ 38.14 | $ 22.78 | $ 172.61 |
| Distributed Generation | kWh | 156 | | $ 1.52 | $ 0.20 | $ 1.07 | $ 0.95 | $ 0.57 | $ 4.31 |

## Table 9 – M-factor Capital Funding Rate Riders, Including HST – HRZ

| HRZ - M-factor Rate Rider Incl HST | Unit | kWh | kW | 2020 | 2021 | 2022 | 2023 | 2024 | Total |
|---|---|---|---|---|---|---|---|---|---|
| Residential | kWh | 750 | | $ 0.23 | $ 0.16 | $ 0.19 | $ 0.15 | $ 0.23 | $ 0.98 |
| General Service Less Than 50 Kw | kWh | 2,000 | | $ 0.56 | $ 0.39 | $ 0.47 | $ 0.36 | $ 0.56 | $ 2.34 |
| General Service 50 To 4,999 Kw | kW | 110,000 | 250 | $ 9.76 | $ 6.91 | $ 8.16 | $ 6.35 | $ 9.83 | $ 41.01 |
| Large Use | kW | 2,555,000 | 5,000 | $ 294.17 | $ 208.28 | $ 245.81 | $ 191.47 | $ 296.35 | $ 1,236.09 |
| Large Use With Dedicated Assets | kW | 10,220,000 | 20,000 | $ 117.40 | $ 83.12 | $ 98.10 | $ 76.41 | $ 118.27 | $ 493.30 |
| Unmetered Scattered Load | kWh | 250 | | $ 0.11 | $ 0.08 | $ 0.09 | $ 0.07 | $ 0.11 | $ 0.47 |
| Sentinel Lighting | kW | 97,008 | 216 | $ 31.26 | $ 22.13 | $ 26.12 | $ 20.35 | $ 31.49 | $ 131.35 |
| Street Lighting | kW | 1,782,038 | 4,974 | $ 240.86 | $ 170.54 | $ 201.26 | $ 156.77 | $ 242.64 | $ 1,012.07 |

## Table 10 – M-factor Capital Funding Rate Riders, Including HST – PRZ

| PRZ - M-factor Rate Rider Incl HST | Unit | kWh | kW | 2020 | 2021 | 2022 | 2023 | 2024 | Total |
|---|---|---|---|---|---|---|---|---|---|
| Residential | kWh | 750 | | $ 0.32 | $ 0.18 | $ 0.22 | $ 0.49 | $ 0.29 | $ 1.50 |
| General Service Less Than 50 Kw | kWh | 2,000 | | $ 0.68 | $ 0.38 | $ 0.46 | $ 1.04 | $ 0.62 | $ 3.19 |
| General Service 50 To 4,999 Kw | kW | 80,000 | 250 | $ 13.34 | $ 7.42 | $ 9.05 | $ 20.47 | $ 12.21 | $ 62.50 |
| Large Use | kW | 2,800,000 | 7,350 | $ 252.45 | $ 140.45 | $ 171.34 | $ 387.40 | $ 231.07 | $ 1,182.70 |
| Unmetered Scattered Load | kWh | 150 | 0 | $ 0.13 | $ 0.07 | $ 0.09 | $ 0.20 | $ 0.12 | $ 0.60 |
| Sentinel Lighting | kW | 180 | 1 | $ 0.16 | $ 0.09 | $ 0.11 | $ 0.24 | $ 0.14 | $ 0.74 |
| Street Lighting | kW | 280 | 1 | $ 0.08 | $ 0.05 | $ 0.06 | $ 0.13 | $ 0.08 | $ 0.39 |

## Table 11 – M-factor Capital Funding Rate Riders, Including HST – GRZ

| GRZ - M-factor Rate Rider Incl HST | Unit | kWh | kW | 2020 | 2021 | 2022 | 2023 | 2024 | Total |
|---|---|---|---|---|---|---|---|---|---|
| Residential | kWh | 750 | | $ 0.03 | $ 0.07 | $ 0.15 | $ 0.15 | $ 0.09 | $ 0.49 |
| General Service Less Than 50 Kw | kWh | 2,000 | | $ 0.05 | $ 0.11 | $ 0.23 | $ 0.24 | $ 0.14 | $ 0.76 |
| General Service 50 To 999 Kw | kW | 189,800 | 500 | $ 1.85 | $ 4.02 | $ 8.54 | $ 8.89 | $ 5.11 | $ 28.39 |
| General Service 1,000 To 4,999 Kw | kW | 489,100 | 1,000 | $ 4.31 | $ 9.35 | $ 19.89 | $ 20.70 | $ 11.89 | $ 66.14 |
| Large Use | kW | 4,215,750 | 7,500 | $ 25.76 | $ 55.93 | $ 118.91 | $ 123.79 | $ 71.12 | $ 395.51 |
| Unmetered Scattered Load | kWh | 750 | | $ 0.03 | $ 0.06 | $ 0.12 | $ 0.12 | $ 0.07 | $ 0.39 |
| Sentinel Lighting | kW | 140 | 2 | $ 0.03 | $ 0.06 | $ 0.13 | $ 0.14 | $ 0.08 | $ 0.44 |
| Street Lighting | kW | 800,000 | 2,200 | $ 26.75 | $ 58.09 | $ 123.49 | $ 128.56 | $ 73.86 | $ 410.76 |

**Impact of the M-factor**

The following tables provide the average annual bill impact of the M-factor, for each rate class in each of the rate zones. The average annual total bill impact for a typical residential customer ranges from 0.09% to 0.28%. The bill impacts are indeed minimal and but provide customers with the assurance that necessary investments are funded, while providing customers with both certainty and stability. The annual bill impacts for each rate class in each of the rate zones is included in the M-factor model, filed as Attachment 3.

**Bill Impacts**

Tables 12 to 16 below identify the average annual bill impact by rate class as a result of the addition of the 2020 to 2024 M-factor rate riders.

**Table 12– M-factor Bill Impacts (Total Bill) – ERZ**

| ERZ - M-factor bill impact | Unit | kWh | kW | Avg. Annual Rider | Avg. Annual % Increase vs. Total Bill |
|---|---|---|---|---|---|
| Residential | kWh | 750 | | $ 0.19 | 0.18% |
| General Service < 50 kW | kWh | 2,000 | | $ 0.55 | 0.19% |
| General Service 50 to 499 kW | kW | 100,000 | 230 | $ 9.85 | 0.06% |
| General Service 500 to 4999 kW | kW | 400,000 | 2,250 | $ 61.33 | 0.08% |
| Large Use | kW | 3,000,000 | 5,000 | $ 246.61 | 0.05% |
| Unmetered | kWh | 300 | | $ 0.12 | 0.23% |
| Street Lighting | kW | 33 | 0 | $ 0.02 | 0.57% |

**Table 13 – M-factor Bill Impacts (Total Bill) – BRZ**

| BRZ - M-factor bill impact | Unit | kWh | kW | Avg. Annual Rider | Avg. Annual % Increase vs. Total Bill |
|---|---|---|---|---|---|
| Residential | kWh | 750 | | $ 0.18 | 0.17% |
| General Service < 50 kW | kWh | 2,000 | | $ 0.45 | 0.17% |
| General Service 50 to 699 kW | kW | 182,500 | 500 | $ 12.82 | 0.05% |
| General Service 700 to 4999 kW | kW | 627,216 | 1,432 | $ 48.55 | 0.05% |
| Large Use | kW | 10,220,000 | 20,000 | $ 453.16 | 0.03% |
| Unmetered | kWh | 21,296 | | $ 3.51 | 0.09% |
| Street Lighting | kW | 2,787,508 | 7,922 | $ 758.63 | 0.14% |
| Embedded Distributor | kWh | 1,417,701 | 4,000 | $ 34.52 | 0.02% |
| Distributed Generation | kWh | 156 | | $ 0.86 | 0.60% |

### Table 14 – M-factor Bill Impacts (Total Bill) – HRZ

| HRZ - M-factor bill impact | Unit | kWh | kW | Avg. Annual Rider | Avg. Annual % Increase vs. Total Bill |
|---|---|---|---|---|---|
| Residential | kWh | 750 | | $ 0.20 | 0.18% |
| General Service Less Than 50 Kw | kWh | 2,000 | | $ 0.47 | 0.17% |
| General Service 50 To 4,999 Kw | kW | 110,000 | 250 | $ 8.20 | 0.05% |
| Large Use | kW | 2,555,000 | 5,000 | $ 247.22 | 0.06% |
| Large Use With Dedicated Assets | kW | 10,220,000 | 20,000 | $ 98.66 | 0.01% |
| Unmetered Scattered Load | kWh | 250 | | $ 0.09 | 0.24% |
| Sentinel Lighting | kW | 97,008 | 216 | $ 26.27 | 0.12% |
| Street Lighting | kW | 1,782,038 | 4,974 | $ 202.41 | 0.05% |

### Table 15 – M-factor Bill Impacts (Total Bill) – PRZ

| PRZ - M-factor bill impact | Unit | kWh | kW | Avg. Annual Rider | Avg. Annual % Increase vs. Total Bill |
|---|---|---|---|---|---|
| Residential | kWh | 750 | | $ 0.30 | 0.28% |
| General Service Less Than 50 Kw | kWh | 2,000 | | $ 0.64 | 0.23% |
| General Service 50 To 4,999 Kw | kW | 80,000 | 250 | $ 12.50 | 0.10% |
| Large Use | kW | 2,800,000 | 7,350 | $ 236.54 | 0.06% |
| Unmetered Scattered Load | kWh | 150 | 0 | $ 0.12 | 0.41% |
| Sentinel Lighting | kW | 180 | 1 | $ 0.15 | 0.41% |
| Street Lighting | kW | 280 | 1 | $ 0.08 | 0.15% |

### Table 16 – M-factor Bill Impacts (Total Bill) – GRZ

| GRZ - M-factor bill impact | Unit | kWh | kW | Avg. Annual Rider | Avg. Annual % Increase vs. Total Bill |
|---|---|---|---|---|---|
| Residential | kWh | 750 | | $ 0.10 | 0.09% |
| General Service Less Than 50 Kw | kWh | 2,000 | | $ 0.15 | 0.06% |
| General Service 50 To 999 Kw | kW | 189,800 | 500 | $ 5.68 | 0.02% |
| General Service 1,000 To 4,999 Kw | kW | 489,100 | 1,000 | $ 13.23 | 0.02% |
| Large Use | kW | 4,215,750 | 7,500 | $ 79.10 | 0.01% |
| Unmetered Scattered Load | kWh | 750 | | $ 0.08 | 0.04% |
| Sentinel Lighting | kW | 140 | 2 | $ 0.09 | 0.13% |
| Street Lighting | kW | 800,000 | 2,200 | $ 82.15 | 0.05% |

# Exhibit 2, Tab 1, Schedule 4

# Establishment of New Deferral and Variance Accounts

# ESTABLISHMENT OF NEW DEFERRAL AND VARIANCE ACCOUNTS

In order to mitigate risk for customers, and to address uncertainties in its future investment needs, Alectra Utilities is requesting approval to establish four new variance accounts. First is a symmetric Capital Investment Variance Account ("CIVA") to track the difference between the capital funding provided through M-factor riders and the actual capital investments during the term of the DSP. Customers will be refunded for overall under-investment; any prudent spending above the level funded through M-factor riders will be recovered by Alectra Utilities. Second is an Externally Driven Capital Variance Account ("EDCVA"), which would capture the difference between the revenue requirement in rates associated with externally-driven capital expenditures related to regional transit projects and capital works required by road authorities. Third, is a Customer Service Rules-related Lost Revenue Deferral Account ("CSRLRDA") to address unforeseeable lost revenue due to a number of factors, including the OEB's recent changes to the customer service rules and disconnections/ reconnections charges. Fourth is a Conservation Demand Management Severance Deferral Account ("CDMSDA") for the recovery of severance costs to address the termination of the Energy Conservation Agreement ("ECA"), resulting in material and unexpected costs for Alectra Utilities. These are described in greater detail as follows.

## Proposed Account: CIVA

Subject to the OEB's approval of the M-Factor, Alectra Utilities proposes a symmetrical CIVA for the 2020-2024 term of the DSP. Alectra Utilities proposes to track variances between the actual and forecast capital related revenue requirement for the DSP term. The capital related revenue requirement is used to calculate the M-Factor for riders applicable in each rate zone.

The proposed CIVA is a practical mechanism by which Alectra Utilities can satisfy three objectives:

i. Provide customers and the utility with both certainty and stability in respect of incremental capital funding over the full five-year term of the DSP;

ii. Track the variance between actual and forecast in-service capital additions in a manner that will be efficiently and transparently reconcilable against the consolidated utility's financial records when the account is cleared; and

iii. Be consistent with the design principle of the M-Factor.

The CIVA amount in each year is derived on an Alectra Utilities-wide basis and by disposing of the CIVA positive and negative balances using a class specific rate rider that is applied to all rate zones.

Calculating the annual CIVA amount on a company-wide basis is consistent with the reality of executing a multi-year capital investment plan. Alectra Utilities anticipates that capital investment priorities will fluctuate between and within rate zones over the term of the DSP, which may result in changes to the scope and timing of projects.

Alectra Utilities requires the flexibility in the execution of the plan to respond to system priorities as a whole. The variance account will be disposed of at the end of the five year term, if applicable.

Consistent with the determination of the maximum M-factor eligible capital at the time of this filing, the CIVA true-up amount must fall within Alectra Utilities' maximum M-factor eligible capital at the time of the true-up based on Alectra Utilities' actual five-year in-service additions. By way of example, Alectra Utilities' total capital envelope, as provided in Table 4, is $0.3B. This is based on total forecasted capital expenditures of $1.5B less the materiality threshold of $1.2B. If actual capital expenditures are $1.3B, then Alectra Utilities' capital envelope is $0.1B (Total capital costs of $1.3B, less the materiality threshold of $1.2B). Therefore, CIVA true-up cannot exceed the capital envelope of $0.1B, determined at the time of the true-up.

The capital related revenue requirement includes depreciation, interest, ROE and PILs applied in the calculation of the forecast capital related revenue requirement for the purposes of determining the applicable M-Factor rider for each rate zone. All components of cost of capital will use the rates, and capital structure, in effect for the year and rate zone for which the capital related revenue requirement is being measured.

**Eligibility Criteria**

The OEB's *Filing Requirements for Electricity Distribution Rate Applications – Chapter 2 Cost of Service*, issued July 12, 2018, specify that requests for new deferral or variance accounts must satisfy the OEB's eligibility criteria of causation, materiality and prudence. The proposed Capital Investment Variance Account satisfies the OEB's eligibility criteria as follows:

Causation – The amounts captured in the CIVA will necessarily be outside of the base upon which Alectra Utilities' rates were derived. The M-Factor will fund capital needs which exceed the capital investments funded through base rates for each RZ. Since the CIVA will capture differences between the actual and forecasted in-service additions over the DSP period, the recovery or refunding those amounts would ensure that Alectra Utilities is not over- or under-funded for its capital expenditure plan.

Materiality – Given the number of projects and the overall scale of the investment funded through the M-Factor, there is a high likelihood that the amounts recorded to the CIVA over the five-year term of the DSP will exceed the $1MM materiality threshold for Alectra Utilities. The utility's base rates will support an average annual capital expenditure of approximately $236MM during the DSP period. The DSP contemplates annual expenditures of approximately $291MM. Alectra Utilities therefore cannot execute $55MM of unfunded capital expenditures in each year, for a total of approximately $275MM of unfunded capital expenditures over the five-year DSP period. The revenue requirement impact of a small variance between forecast and actual in-service capital additions to Alectra Utilities' rate base would be material.

Prudence – The OEB will have an opportunity to review the prudence of any amounts recorded to the CIVA before any recovery is allowed.

Alectra Utilities proposes to record the amounts identified above, as necessary, in Account 1508 Other Regulatory Assets and requests the following new sub-accounts to segregate these amounts:

- 1508 Sub-account "Capital Investment Variance Account.

A draft accounting order for the proposed CIVA, which 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, is provided in Appendix 'A'.

**Proposed Account: Externally Driven Capital Variance Account ("EDCVA")**

Every year, Alectra Utilities is required to remove, relocate, or reconstruct distribution system assets to accommodate projects conducted by road authorities (as defined under the *Public Service Works on Highways Act*, or "PSWHA") or related to regional transit initiatives.[26] This work is mandatory, the timing and scope of the work is not within Alectra Utilities' control, and the need may arise with little notice to the utility. Notwithstanding that the costs of such work are typically shared with the project proponent pursuant to the PSWHA or otherwise, material unplanned expenditures may be required by Alectra Utilities to respond to such externally-driven work.

As shown in Table 17 below, the expenditures required to accommodate road authority and transit projects can be highly volatile. Over the historical period, Alectra Utilities (including its predecessors) have spent between $9.6MM and $31.0MM on such projects each year. Alectra Utilities forecasts expenditures of approximately $20MM per year (net of contributions from project proponents) on such work over the DSP period. However, this forecast only reflects work that Alectra Utilities is currently aware of. In Alectra Utilities' experience, there is a high probability that the need for additional externally driven capital work will arise during the DSP period. It is also possible that some of the currently anticipated road authority or transit projects are modified, deferred or cancelled, thereby affecting the need for distribution system removal, relocation and reconstruction work.

**Table 17: Historical and Proposed Investment Spending on Externally-Driven Capital**

| | Historical Expenditure | | | | Bridge | Forecast Expenditure | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** |
| **CAPEX ($MM)** | $9.6 | $14.4 | $23.5 | $31.0 | $27.9 | $19.7 | $17.3 | $18.2 | $19.2 | $20.3 |

Transit Projects in particular can trigger the need for large scale distribution system relocation and construction. This work is required by federal, provincial, regional, and/or municipal agencies

[26] More detailed information on road authority and transit work during the DSP period is provided in Section 5.4.3 Appendix 3 of the DSP.

in order to support the installation of new rapid transit infrastructure. Alectra Utilities works collaboratively with these agencies during the pre-market, in-market and development phases of the projects to ensure existing distribution infrastructure is relocated in a timely manner to allow for the construction of rapid transit infrastructure. Currently anticipated rapid transit projects for the DSP period include: Hurontario Light Rail Transit, Hamilton Light Rail Transit, and the Regional Express Rail. The pacing, prioritization and overall timing for these relocation projects will be entirely dependent on Metrolinx and other agencies, and will not be known until project schedules are finalized. Alectra Utilities expects that all costs associated with these particular projects will be recoverable from Metrolinx.

As a provincial transit agency implementing rail transit projects in Alectra Utilities service area, Metrolinx is not recognized by Alectra Utilities as road authority under the definition of the PSWHA. Since cost sharing provisions as set out in the PSWHA are not applicable to transit projects implemented by Metrolinx, Alectra Utilities is working to finalize arrangements with Metrolinx to bear all the relocation costs associated with the three identified transit projects. Due to the lack of final designs and project specifics, certain sections of the distribution system required to be relocated may require a different cost sharing arrangement with Metrolinx. For example, in certain rail crossing locations it may be more economic and safe for Alectra Utilities to relocate the distribution from an overhead to an underground crossing. As the final designs, including the specific numbers of crossings to be remediated, have not been finalized by Metrolinx, the costs for distribution relocation work in connection with these projects have not been developed. Alectra Utilities continues to monitor the progress and timelines of the project schedules, which are controlled by Metrolinx.

Investment narratives for the Road Authority and Transit Projects are filed in Appendix A03 to the DSP.

If additional mandatory, externally-driven work beyond the level that is forecasted in the DSP arises during the 2020 to 2024 period, Alectra Utilities would, in the absence of this requested account, need to defer other necessary and planned investments in its distribution system. Deferral of those investments would impede Alectra Utilities' efforts to achieve its planned DSP outcomes. In particular, deferring planned investments to accommodate mandatory, externally-driven work may lead to continued deterioration of overall reliability, continued vulnerability to extreme weather events, increased future renewal costs, and sub-optimal pacing of investments.

Alternatively, if the currently anticipated level of externally-driven work does not materialize over the DSP period, customers would incur costs for work that does not ultimately need to be performed. In order to avoid such impacts, Alectra Utilities requests approval to establish the EDCVA, a variance account to record the differences between the revenue requirement associated with externally driven capital expenditures in rates, as forecasted in Section 5.4.3, Appendix 3 of the DSP, and the actual revenue requirement for in-service additions associated with such projects in the same period. Alectra Utilities intends to true-up the variance account at the end of the five year term. However, Alectra Utiltiies may request earlier disposition of the account from timeto time where balances are material.

**Eligibility Criteria**

The OEB's *Filing Requirements for Electricity Distribution Rate Applications – Chapter 2 Cost of Service*, issued July 12, 2018, specify that requests for new deferral or variance accounts must satisfy the OEB's eligibility criteria of causation, materiality and prudence. The proposed Externally Driven Capital Variance Account satisfies the OEB's eligibility criteria as follows:

Causation – Alectra Utilities is proposing an M-Factor to fund the capital needs identified in its DSP which are incremental to the capital funded through base rates for each of its RZs. The DSP includes forecasts for the capital costs associated with confirmed road authority and transit projects. The proposed EDCVA is intended to capture differences between those forecasts and Alectra Utilities' actual capital costs for such relocation and reconstruction work, including for changes to the scope or timing of anticipated road authority and transit projects and for additional road authority and transit projects not currently contemplated. Consequently, the amounts that would be recorded in the EDCVA would clearly be outside of the base upon which Alectra Utilities' rates will be derived.

Materiality – In Alectra Utilities' experience, there is a high level of uncertainty with large, government-backed infrastructure projects, particularly in the road and transit sectors. This makes it challenging to accurately forecast the capital expenditures associated with related distribution system relocation and reconstruction work. As provided in Table 17, above, the total cost of this work has varied significantly over the historical period but has consistently been material, ranging from $9.6MM in 2015 to $31.0MM in 2018. In that historical period, actual costs have varied materially from forecasts, and Alectra Utilities has no basis to believe that trend will change during the DSP period. The cost of individual externally-driven projects is often significant. For example, the forecast costs of the York Region Rapid Transit VIVA Bus Rapid Transit projects in the utility's EB-2017-0024 and in EB-2018-0016 applications were $11.2MM and $13.3MM, respectively. A 10% variance in either year would result in a material variance from forecast for this single project. As discussed above, the costs to be recorded in the account would have a significant influence on Alectra Utilities' operations. This is because increases in the costs of relocation and reconstruction work, relative to forecasts, would require Alectra Utilities to defer necessary planned investments in its distribution system, which would impede Alectra Utilities' efforts to achieve its planned DSP outcomes.

<u>Prudence</u> – Road authority and transit projects are non-discretionary projects that are driven by third parties who have control over the timing, scope and costs of their projects, which dictate the need, timing, scope and costs of distribution system relocation and reconstruction work. When necessary to accommodate road or transit works, Alectra Utilities is obligated to remove, relocate or reconstruct parts of its distribution infrastructure to allow for the installation of rapid transit and road infrastructure. Therefore, it is reasonable for Alectra Utilities to incur these costs, and its forecasts for the 2020 to 2024 period, which are based on confirmed projects currently known to the company, are reasonable.

The EDCVA would operate symmetrically, such that the revenue requirement associated with any prudent expenditures in excess of the level reflected in rates would be recoverable by the Applicant, and any excess funding in rates would be refundable to customers in a future proceeding. Carrying charges would apply to the opening balances in the account at the OEB-approved rate.

A draft accounting order for the proposed EDCVA, which 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, is provided in Appendix 'B'.

**Proposed Account: Customer Service Rules-related Lost Revenue Variance Account ("CSRLRVA")**

Alectra Utilities requests approval for an accounting order to establish a new variance account to record lost revenue and incremental capital costs resulting from changes to customer service rules, and future policy changes implemented by the OEB.

During the deferred rebasing period, the OEB has amended the customer service rules applicable to Alectra Utilities, imposing material financial consequences that are not addressed in the utility's base rates. Specifically, the OEB imposed a disconnection ban for residential customers during the winter months, as well as amendments to customer service rules relating to billing, disconnections, and service charges for non-payment. These changes result in material additional costs for the utility that are not included in base rates and were not contemplated when the OEB approved the utility's creation in the MAADs Application. Alectra Utilities continues to incur ongoing operating costs to provide these services which include: collection activities; reminder notices; out-bound calls; final notices; and management of field activities. These changes also result in significant programming and coding changes in Alectra Utilities' Customer Information System ("CIS"), Customer Care and Billing System ("CC&B").

On November 2, 2017, the OEB issued a Decision and Order, amending the license conditions of all electricity distributors to permanently prohibit disconnecting residential consumers for reason of non-payment during the winter period. The OEB established a permanent Disconnection Ban Period from November 15th until April 30th of the following calendar year.

On September 6th, 2018, the OEB issued its "Review of Customer Service Rules for Utilities Phase 1" (the "Report"). The Report outlined the findings from the research and engagement activities that the OEB undertook as part of the review, along with the OEB's proposed changes to the rules. The Report invited written comments from interested stakeholders, and encouraged utilities to identify any technical limitations that might affect a utility's ability to implement the proposals set out in the Report. The Report proposed changes to the following customer service rules: security deposits; billing and payments; disconnection for non-payment; and service charges relating to non-payment of accounts.

On December 18, 2018, the OEB provided Notice under sections 70.2 and 45 of the Ontario Energy Board Act, 1998 ("OEB Act") of proposed amendments to the Distribution System Code

("DSC"), the Standard Supply Service Code ("SSSC"), Unit Sub-Metering Code ("USMC") and the Gas Distribution Access Rule ("GDAR"). The amendments were proposed as a result of the OEB's review of its customer service rules and associated service charges for licensed electricity distributors, rate-regulated natural gas distributors and unit sub-meter providers. On March 14, 2019, the OEB issued the final amendments.

In the December 2018 Notice, the OEB acknowledged that the elimination of the charges relating to non-payment of accounts may have an impact on some distributors, and although it will not establish deferral/variance accounts for all distributors, any distributor can apply for a deferral account with evidence demonstrating that such an account would meet the eligibility requirements set out in the OEB's Filing Requirements for Electricity Distribution Rate Applications.

The following table provides a summary of the impact to Alectra Utilities as a result of the following amendments to the Customer Service Rules: Minimum Payment Period; Arrears Payment Agreement; Collection of Account Charge; Disconnect/Reconnection Charge; and Winter Disconnection Ban. The combined revenue requirement impact (reduction) of these items is approximately $2.8MM per year, totalling almost $20MM over the remainder of the deferred rebasing period from 2020 through 2026. Further, Alectra Utilities estimates one-time capital programming costs of $1.0MM. Alectra Utilities will also monitor the impact of these rule changes on its bad debts in order to assess the potential impact.

**Table 18 – Impact of Customer Service Rule Changes**

| **Customer Service Rule** | **OEB Decision** | **Estimated Impact** |
|---|---|---|
| Minimum Payment Period | The Minimum Payment Period before a late payment penalty can be applied should be at least 20 calendar days from the date the bill is issued to the customer. | Alectra Utilities estimates that the combined revenue impact of changes to the Minimum Payment Period and Arrears Payment Arrangements (described below) to be approximately $0.3MM per year. |
| Arrears Payment Agreements | Distributors should not apply late payment charges on the amount covered by the Arrears Payment Agreements for all residential customers. | As provided above, Alectra Utilities estimates the impact to be approximately $0.3MM per year. |
| Collection of Account Charge | Customer should not be charged the Collection of Account Charge. | Alectra Utilities estimates the combined revenue impact of the removal of the collection of account charge and winter disconnection ban to be approximately $2.5MM per year. |
| Winter Disconnection Ban | Distributors are prohibited from disconnecting customer for non-payment from November 15 to April 30 each year. | As provided above, Alectra Utilities estimates the impact to be approximately $2.5MM per year. |
| Disconnect/Reconnect Charge | Distributors are required to waive the Disconnect/Reconnect charge for eligible low-income customers. | Alectra Utilities estimates the revenue impact to be approximately $0.02MM per year. |

**Eligibility Criteria**

The OEB's *Filing Requirements for Electricity Distribution Rate Applications – Chapter 2 Cost of Service*, issued July 12, 2018, specify that requests for new deferral or variance accounts must satisfy the OEB's eligibility criteria of causation, materiality and prudence. The proposed Deferral Account satisfies the OEB's eligibility criteria as follows:

<u>Causation</u> – *The forecasted expense must be clearly outside of the base upon which rates were derived.* The proposed deferral account is intended to capture the financial impacts of OEB policy changes during the rebasing deferral period. Consequently, the amounts that would be recorded in the deferral account would clearly be outside of the base upon which Alectra Utilities' rates will be derived.

<u>Materiality</u> – *The forecasted amounts must exceed the Board-defined materiality threshold and have a significant influence on the operation of the distributor; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements.* The implementation of the above-mentioned OEB policy changes outside of a rebasing has a material impact to Alectra Utilities' revenue requirement, in the amount of approximately $2.85MM annually, which significantly exceeds Alectra Utilities' materiality threshold of $1MM, as defined in section 2.0.8 of the OEB's Chapter 2 Filing Requirements. This impact is compounded as Alectra Utilities is in a rebasing deferral period.

<u>Prudence</u> – The revenue impact is a result of OEB policy changes, and it is therefore reasonable for Alectra Utilities to record this financial impact in an OEB-approved deferral account, and to seek recovery in a future proceeding.

A draft accounting order for the proposed deferral account, which 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, is provided in Appendix 'C'.

**Proposed Account: Conservation Demand Management Severance Deferral Account ("CDMSDA")**

On March 21, 2019, the Minister of Energy, Northern Development and Mines issued a directive to the Independent Electricity System Operator ("IESO") to discontinue the Conservation First

Framework and associated Conservation and Demand Management ("CDM") activities, taking all reasonable efforts to minimize the associated costs. Pursuant to the Ministerial Directive, the IESO issued a Notice of Termination of the Energy Conservation Agreement ("ECA") to Alectra Utilities and directed it to use commercially reasonable efforts to minimize expenditures associated with the termination of the Conservation First Framework and associated CDM activities.

Following the receipt of the Notice of Termination, Alectra Utilities developed a CDM Wind Down resource plan which was implemented on May 1, 2019. The CDM Wind Down resource plan included steps (i) to wind down Alectra Utilities' CDM business, including terminating employees involved in the CDM operations, and (ii) to terminate all activities associated with the marketing of conservation programs, solicitation of participants, and the execution of Participant Agreements. Alectra Utilities submitted its CDM Wind Down Estimate to the IESO containing post termination administration costs including employee separation costs required to meet the surviving obligations of the ECA. The IESO has 60 business days to review and approve Alectra Utilities' Wind Down estimate.

These additional severance costs are unexpected and material for Alectra Utilities. In the event that the IESO denies the funding of the severance costs, Alectra Utilities seeks a deferral account for recovery of the severance costs.

**Eligibility Criteria**

The OEB's *Filing Requirements for Electricity Distribution Rate Applications – Chapter 2 Cost of Service*, issued July 12, 2018, specify that requests for new deferral or variance accounts must satisfy the OEB's eligibility criteria of causation, materiality and prudence. The proposed CDMSDA satisfies the OEB's eligibility criteria as follows:

> <u>Causation</u> – As a condition of its electricity distribution licence, Alectra Utilities was required to promote and support the provincial CDM policy and to achieve specific CDM targets through the delivery of CDM programs in its service territory. To meet its obligations, Alectra Utilities created the CDM group within its business and retained specialized employees to achieve its targets. As discussed above, pursuant to the Ministerial Directive, the IESO was directed to terminate the Conservation First Framework and the associated CDM activities. As a result of this directive, Alectra Utilities

had to wind down its CDM operations, which included, among other things, terminating employees that were involved in CDM activities and paying those employees associated severance packages.

Materiality – The forecasted amounts must exceed the Board-defined materiality threshold and have a significant influence on the operation of the distributor; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements. The implementation of the above-mentioned OEB policy changes outside of a rebasing has a material impact on Alectra Utilities' in the amount of approximately $3.2MM, which significantly exceeds Alectra Utilities' materiality threshold of $1MM, as defined in section 2.0.8 of the OEB's Chapter 2 Filing Requirements.

Prudence – The revenue impact is a result of Provincial energy policy changes, and it is therefore reasonable for Alectra Utilities to record this financial impact in an OEB-approved deferral account, and to seek recovery in a future proceeding.

A draft accounting order for the proposed deferral account, which 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, is provided in Appendix 'D'.

***Appendix 'A' – Draft Accounting Order – Capital Investment Variance Account (CIVA)***

Alectra Utilities will establish the following variance accounts:

1. 1508, Other Regulatory Assets, Sub-account M-factor Capital Investment Variance
2. 1508, Other Regulatory Assets, Sub-account M-factor Capital Investment Variance Carrying Charges

In Account 1508 Other Regulatory Assets, Sub-account M-factor Captial Investment Variance, Alectra Utilities will record the difference between the actual and forecast capital related revenue requirement over the DSP term. Carrying charges at the OEB prescribed rate will apply to the principal sub-account.

The sample journal entries are provided below:

Dr. 1508, Other Regulatory Assets, Sub-account M-factor Capital Investment Variance

Cr. Property, Plant and Equipment (various accounts)

To record the difference between the actual and forecast in-service capital related revenue requirement

Dr. 1508, Other Regulatory Assets, Sub-account M-factor Capital Investment Variance Carrying Charges

Cr. 4405, Interest and Dividend Income

To record the carrying charges on the monthly opening balance in Account 1508 Other Regulatory Assets, Sub-account M-factor Capital Investment Variance

Alectra Utilities proposes to apply to the OEB to clear the balance in the variance account through rate riders at the end of the DSP period.

***Appendix 'B' – Draft Accounting Order* - Externally Driven Capital Variance Account *("EDCVA")***

Alectra Utilities will establish the following variance accounts:

1. 1508, Other Regulatory Assets, Sub-account Externally Driven Capital
2. 1508, Other Regulatory Assets, Sub-account Externally Driven Capital Carrying Charges

In Account 1508 Other Regulatory Assets, Sub-account Externally Driven Capital, Alectra Utilities will record the difference between the level of capital spend included in the DSP for externally driven investments, and the amounts incurred over the 2020 to 2024 DSP period, in the newly established variance account.

The sample journal entries are provided below:

Dr. 1508, Other Regulatory Assets, Sub-account Externally Driven Capital

Cr. Property, Plant and Equipment (various accounts)

To record the difference between the actual and forecast in-service Externally Driven Capital Investments

Dr. 1508, Other Regulatory Assets, Sub-account Externally Driven Captial Carrying Charges

Cr. 4405, Interest and Dividend Income

To record the carrying charges on the monthly opening balance in Account 1508 Other Regulatory Assets, Sub-account Externally Driven Capital

Alectra Utilities proposes to apply to the OEB to clear the balance in the variance account through rate riders at the end of the DSP period.

***Appendix 'C' – Draft Accounting Order - Customer Service Rules-related Lost Revenue Variance Account ("CSRLRVA")***

Alectra Utilities will establish the following variance accounts:

1. 1508, Other Regulatory Assets, Sub-account Customer Service Rules-related Lost Revenue
2. 1508, Other Regulatory Assets, Sub-account Customer Service Rules-related Lost Revenue Carrying Charges
3. 1508, Other Regulatory Assets, Sub-account Customer Service Rules-related Incremental Capital Cost
4. 1508, Other Regulatory Assets, Sub-account Customer Service Rules-related Incremental Captial Cost Carrying Charges

In Account 1508 Other Regulatory Assets, Sub-account Customer Service Rules-related Lost Revenue, Alectra Utilities will record the difference between revenues collected prior to the Customer Service Rule changes and revenues collected based on the Customer Service Rule changes established pursuant to the March 14, 2019 final amendements, issued by the OEB.

The sample journal entries are provided below:

Dr. 1508, Other Regulatory Assets, Sub-account Customer Service Rules-related Lost Revenue

Cr. 4235 Miscellaneous Service Revenues

To record lost revenue associated with the Customer Service Rule changes

Dr. 1508, Other Regulatory Assets, Sub-account Customer Service Rules-related Lost Revenue Carrying Charges

Cr. 4405, Interest and Dividend Income

To record the carrying charges on the monthly opening balance in Account 1508 Other Regulatory Assets, Sub-account Customer Service Rules-related Lost Revenue

In Account 1508 Other Regulatory Assets, Sub-account Customer Service Rules-related Incremental Capital Cost, Alectra Utilities will record the incremental capital programming costs resulting from changes to customer service rules.

The sample journal entries are provided below:

Dr. 1508, Other Regulatory Assets, Sub-account Customer Service Rules-related Incremental Captial Cost

Cr. 1611, Intangible Plant

To record incremental capital costs resulting from customer service rule changes

Dr. 1508, Other Regulatory Assets, Sub-account Customer Service Rules-related Incremental Capital Cost Carrying Charges

Cr. 4405, Interest and Dividend Income

To record the carrying charges on the monthly opening balance in Account 1508 Other Regulatory Assets, Sub-account Customer Service Rules-related Incremental Captial Cost

***Appendix 'D' – Draft Accounting Order - Conservation Demand Management Severance Deferral Account ("CDMSA")***

Alectra Utilities will establish the following variance accounts:

1. 1508, Other Regulatory Assets, Sub-account CDM Severance
2. 1508, Other Regulatory Assets, Sub-account CDM Severance Carrying Charges

In Account 1508 Other Regulatory Assets, Sub-account CDM Severance, Alectra Utilities will record the severance costs resulting from the termination of the ECA.

The sample journal entries are provided below:

Dr. 1508, Other Regulatory Assets, Sub-account CDM Severance

    Cr. 1005, Cash

To record severance costs resulting from the termination of the ECA

Dr. 1508, Other Regulatory Assets, Sub-account CDM Severance Carrying Charges

    Cr. 4405, Interest and Dividend Income

To record the carrying charges on the monthly opening balance in Account 1508 Other Regulatory Assets, Sub-account CDM Severance

# Exhibit 2, Tab 1, Schedule 5

# Capitalization Policy

## CAPITALIZATION POLICY

Alectra Utilities conformed its capitalization policy in 2017 (as a result of the consolidation through which Alectra Utilities was formed, and as required under the International Financial Reporting Standards ("IFRS")) to align the capitalization policies for the Alectra Utilities rate zones.

IFRS 10 *Consolidated Financial Statements,* states that uniform accounting policies have to 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.

For the predecessor companies that formed Alectra Utilities, PowerStream is the acquirer in accordance with IFRS 3 and IFRS 10. Consequently, Alectra Utilities adopted the PowerStream capitalization policy.

During the 2018 EDR Application proceeding (EB-2017-0024), in Procedural Order ("PO") No. 3, the OEB established three new deferral accounts to track the change in capitalization policy for the Horizon Utilities, Enersource and Brampton RZs. In the 2018 EDR Application Decision, the OEB stated that:

> *"For the remainder of the Custom IR term, the effect on earnings resulting from the change in the capitalization policy will be dealt with through the ESM. Once the Custom IR term ends, the Horizon Utilities RZ will move to Price Cap IR per the MAADs policy, and it will be treated consistently with the Brampton and Enersource RZs. Alectra Utilities shall retain the deferral account opened for Horizon Utilities RZ, however, the first entries to the account shall begin January 1, 2020. The Brampton and Enersource RZs are on Price Cap IR. For these rates zones, the OEB finds it appropriate to retain the balances recorded in the deferral accounts approved in the Decision and Partial Accounting Order effective February 1, 2017.*

Further, the OEB stated that:

> *"Given the complexities of determining amounts that should be credited to customers, such as tax treatment, the OEB finds that Alectra Utilities shall file a*

*proposal for disposition of the deferral accounts in its application for 2019 rates for the Brampton and Enersource RZs*[27]*."*

In this Application, there are two aspects related the change in capitalization policy for the OEB to determine. First, Alectra Utilities requests that the OEB reverse the outcome of its previous decision to create the capitalization deferral accounts for each of the Brampton, Enersource and Horizon Utilities RZs. This is on the basis that the change to the capitalization policy has no cash consequences and is an inappropriate change to Alectra Utilities' revenue requirement during the rebasing deferral period; as such, it is contrary to the OEB's MAADs policy. Second, subject to the OEB's determination of the first issue, Alectra Utilities requests that the OEB determine the basis for recording balances in the capitalization deferral accounts and the treatment of the ESM for the Horizon Utilities RZ, in light of the capitalization policy change.

**Reconsideration of Capitalization Policy Treatment**

For the reasons set out below, to establish just and reasonable rates, the OEB should reconsider its capitalization decision in EB-2017-0024 and no longer require the use of deferral accounts or the future disposition of recorded balances.

As explained below, the accounting policy change was required under IFRS solely for external reporting purposes. The OEB's decision in EB-2017-0024 implies that such policy change should be adopted for MIFRS purposes, as well. However, in the context of a rebasing deferral period, a change in capitalization policy has no impact on cash flow. The cash flow derived from the existing rate revenue is required to fund distribution activities independent of the accounting change related to whether expenditures are considered as operating or capital expenditures from an accounting perspective. The cash flow requirements do not change since the change in recognition of an operating and capital expense is "non-cash". The OEB decision to use deferral accounts has the directly opposite effect of converting a non-cash consequence to cash by reducing reduce revenue through the use of deferral accounts. The direct result of this decision is to immediately reduce the funding for distribution related activities – annually, over the 10-year period. The OEB's decision does not reallocate existing cash. Instead, as a result of the OEB's decision, Alectra Utilities suffers a cash impairment and corresponding cost from the OEB's

[27] EB-2017-0024 pg. 81

treatment of an accounting change that is wholly non-cash based. This is counter-intuitive to MAADs policy and the OEB decision establishing a 10-year re-basing deferral period within which merger consequences and benefits of a financial nature are for the account of shareholders. The OEB decision serves to bifurcate a non-cash outcome into a cash cost for shareholders and a cash benefit for customers.

The application of the deferral mechanism imposed by the OEB in EB-2017-0024 is tantamount to the rebasing of Alectra Utilities' revenue requirement by way of change to a singular and isolated aspect. This is inappropriate and inconsistent with the OEB's MAADs policy (which, in part, seeks to "*reduce the risk of a MAADs transaction*[28]") and the Decision of the Board in Alectra Utilities' MAADs Application (EB-2016-0025), which granted a 10-year rebasing deferral period. Furthermore, the MAADs policy includes an earnings sharing mechanism to address OEB, customer, intervenors concerns regarding shareholder windfalls.

Rebasing an isolated issue in this manner does not consider the full range of impact of other uncontrollable events that may impact the revenue of a distributor. Examples of this in the case of Alectra Utilities would be: i) the imposition of monthly billing costs on distributors; or ii) changes to customer service rules, including the imposition of a ban on winter disconnections. Each of these have significant implication to the revenue and cost structure of Alectra and occurred post predecessor re-basing. Alectra Utilities submits that it is inappropriate for the Board to choose isolated issues for rebasing in a rebasing deferral period as: i) this is inconsistent with its own MAADs policy as described above; and ii) it is an inequitable approach considering other externalities with adverse financial consequences for which relief is unavailable in a rebasing deferral period. OEB policies should set a basis of reasonable predictability of outcomes for distributors.

The Ontario Energy Board Modernization Review Panel Final Report (the "Dicerni Report") identified the predictability of regulatory processes as a key characteristic of regulatory excellence. In defining [C]ertainty as one of the five key characteristics that regulators should embody, the Dicerni Report states:

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[28] EB-2014-0138 – Report of the Board: Rate-Making Associated with Distributor Consolidation, p.6

> *"Certainty: Regulatory processes should be as predictable as possible. Regulated entities should understand what is expected of them…*[29]*"*

Accounting policy conformance is a foreseeable necessity resulting from a merger and was foreseen in the Alectra Utilities MAADs application, although the full scope of such is impractical to analyze until parties to a merger actually merge. Accounting policies for MIFRS purposes are generally reviewed by the OEB at the time of a rebasing. Alectra Utilities submits that such accounting policy changes within a rebasing deferral period should not affect rates as these are ultimately non-cash. Additionally, and importantly, customers are unaffected during such period since rate expectations remain consistent with the approved rate basis existing just prior to the merger.

Lastly, rate-making impacts from accounting policy changes are best considered in the broadest context of rate-making policy at the time of a full rebasing with appropriate re-balancing of revenue with consideration of all components of rate-base and the impacts of prior externalities and OEB policy changes. Such an approach will ensure a full and complete re-balancing of rates relative to rate-base and operating costs at that time with the result that customers and shareholders remain indifferent to such considerations within the rebasing deferral period.

**Calculation of Capitalization Impact**

During the 2019 EDR Application proceeding (EB-2018-0016), in PO No. 3, the OEB deferred the capitalization policy issue, of calculating the capitalization impact for purposes of recording balances in the capitalization deferral accounts, to Alectra Utilities' 2020 EDR Application, and directed Alectra Utilities to file a forecast to the end of the deferred rebasing period for all options provided for the Enersource, Brampton and Horizon Utilities rate zones. The OEB stated that:

> *"Given that the OEB wants to assess different options, there were two approaches it considered. The first was to direct Alectra Utilities to complete the information requested by SEC to file in this 2019 rate proceeding. The second was to defer consideration of this issue and direct Alectra Utilities to file a comparison of different options and its preferred option in its 2020 rate application. The OEB is*

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[29] *The Ontario Energy Board Modernization Review Panel Final Report*, p. 10, dated October 2018, issued March 15, 2019.

> *adopting the latter approach as it will allow Alectra Utilities sufficient time to consider different options and provide supporting evidence. In developing options, Alectra Utilities is expected to take into consideration options proposed in this proceeding, including options involving adjustments to rate base[30].”*

The Procedural Order also provided for an oral hearing that was convened on December 5 and 6, 2018 to address in part the ESM for the Horizon Utilities RZ. The Parties reached a Settlement Agreement on the ESM for the Horizon Utilities RZ. The Parties agreed that the allocation of costs between Alectra Utilities' RZs, to determine the Horizon Utilities RZ ESM for 2017 and the interaction between the calculation and the change in capitalization policy, should be deferred to the 2020 EDR Application proceeding. Further details on the ESM for Horizon Utilities, and the impact of the capitalization policy on the ESM calculation, is provided in Exhibit 3, Tab 1, Schedule 2 of the Application.

In the 2019 EDR Application proceeding, SEC and OEB staff provided calculations of the impact of the capitalization policy. SEC filed its calculation on October 31, 2018, as directed in PO No. 2. In its submission, SEC stated that: *"It may be, based on the evidence, that the approach of using Account 1576 to adjust rate base over time would work better than annual revenue requirement adjustments, and although that approach was rejected in EB-2017-0024, it should now be reconsidered in light of new information".* OEB Staff submitted a calculation on the impact of the capitalization policy change on regulatory net earnings, as part of its assessment of the ESM for the Horizon Utilities RZ. OEB Staff's submission was filed as Exhibit K1.4 (Note 3: Effects of Changes in Accounting Policy), on December 5, 2018. Alectra Utilities provides a comparison and discussion of the various approaches below, in addition to its preferred approach.

Table 19, below provides a comparison of the net impact of the capitalization policy change, based on the various approaches to the calculation, as identified by SEC, OEB Staff and Alectra Utilities. To illustrate the various approaches, Alectra Utilities has summarized the impact based on 2017 actuals.

**Table 19 – Capitalization Policy Impact – Calculation Methodologies**

[30] EB-2018-0016 – Decision on Confidentiality and Procedural Order No. 3, dated November 8, 2018, p.2

| Capitalization Policy Impact Reporting Period: 2017 | Alectra Approach EB-2018-0016 | SEC Approach EB-2018-0016[1] | OEB Staff Approach EB-2018-0016 | Alectra REVISED EB-2019-0018 | Comments |
|---|---|---|---|---|---|
| Brampton RZ | $1,211,711 | $1,671,303 | $1,365,172 | $1,671,303 | Recovery from customers |
| Enersource RZ | ($1,247,499) | ($1,716,775) | ($1,386,982) | ($1,716,767) | Refund to customers |
| PowerStream RZ | ($131,217) | ($180,076) | ($144,473) | ($180,076) | Refund to customers |
| Horizon Utilities RZ | ($3,663,090) | ($5,022,498) | ($3,998,290) | ($5,022,498) | Flows through the ESM |
| **Total Net Impact** | **($3,830,095)** | **($5,248,046)** | **($4,164,573)** | **($5,248,037)** | |

*1. SEC's calculation did not include an impact for the PRZ. Alectra has included the impact for the PRZ to facilitate a comparison of the various approaches*

Alectra Utilities has considered different options to the calculation of the impact of the capitalization policy change, and has updated its calculation of the PILs impact. The main difference between Alectra Utilities' approach in EB-2018-0016 and SEC's approach was the treatment for PILs. Alectra Utilities initially calculated PILs on an actual taxes payable basis, and has updated its calculation to determine the PILs impact on a revenue requirement basis, consistent with the OEB's PILs model. OEB staff has calculated PILs on an actual taxes payable basis.

Table 20 below provides a forecast of the net impact of the capitalization policy change over the deferred rebasing period based on Alectra Utilities' and SEC's approach.

## Table 20 – Net Impact of Capitalization Policy Change (10 year forecast)

| Capitalization Policy Impact ($000s) | 2017_Act | 2018_Act | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2017-2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| OM&A | (1,831) | (1,610) | (2,350) | (2,350) | (2,350) | (2,350) | (2,350) | (2,350) | (2,350) | (2,350) | (22,238) |
| Depreciation | 23 | 66 | 168 | 235 | 302 | 369 | 436 | 504 | 571 | 638 | 3,311 |
| PILs | 6 | (5) | 10 | 4 | 3 | 5 | 10 | 17 | 27 | 39 | 117 |
| Return | 130 | 241 | 399 | 551 | 699 | 841 | 979 | 1,112 | 1,240 | 1,364 | 7,557 |
| **Total Net Impact_BRZ** | **(1,671)** | **(1,308)** | **(1,774)** | **(1,559)** | **(1,346)** | **(1,134)** | **(924)** | **(717)** | **(511)** | **(309)** | **(11,253)** |

| Capitalization Policy Impact ($000s) | 2017_Act | 2018_Act | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2017-2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| OM&A | 1,866 | 1,712 | 1,792 | 1,792 | 1,792 | 1,792 | 1,792 | 1,792 | 1,792 | 1,792 | 17,913 |
| Depreciation | (24) | (68) | (115) | (163) | (211) | (259) | (307) | (354) | (402) | (450) | (2,353) |
| PILs | (5) | 7 | 13 | 17 | 18 | 16 | 13 | 7 | (1) | (10) | 74 |
| Return | (120) | (227) | (336) | (442) | (545) | (645) | (741) | (835) | (925) | (1,012) | (5,827) |
| **Total Net Impact_ERZ** | **1,717** | **1,424** | **1,354** | **1,204** | **1,054** | **905** | **757** | **610** | **464** | **320** | **9,807** |

| Capitalization Policy Impact ($000s) | 2017_Act | 2018_Act | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2017-2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| OM&A | 194 | 410 | 531 | 536 | 536 | 536 | 536 | 536 | 536 | 536 | 4,888 |
| Depreciation | (2) | (9) | (19) | (31) | (43) | (55) | (67) | (79) | (91) | (103) | (499) |
| PILs | (0) | 1 | 3 | 6 | 8 | 9 | 9 | 9 | 8 | 6 | 57 |
| Return | (11) | (34) | (64) | (93) | (121) | (149) | (176) | (202) | (228) | (253) | (1,329) |
| **Total Net Impact_PRZ** | **180** | **367** | **451** | **418** | **380** | **341** | **303** | **264** | **226** | **187** | **3,118** |

| Capitalization Policy Impact ($000s) | 2017_Act | 2018_Act | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2017-2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| OM&A | 5,399 | 5,243 | 6,379 | 6,544 | 6,715 | 6,715 | 6,715 | 6,715 | 6,715 | 6,715 | 63,856 |
| Depreciation | (67) | (200) | (395) | (557) | (722) | (888) | (1,054) | (1,220) | (1,385) | (1,551) | (8,040) |
| PILs | (14) | 18 | 20 | 40 | 52 | 55 | 50 | 37 | 17 | (10) | 266 |
| Return | (295) | (593) | (946) | (1,293) | (1,640) | (1,977) | (2,304) | (2,622) | (2,931) | (3,230) | (17,830) |
| **Total Net Impact_HRZ[1]** | **5,022** | **4,467** | **5,057** | **4,735** | **4,405** | **3,906** | **3,408** | **2,911** | **2,416** | **1,925** | **38,252** |

| Capitalization Policy Impact ($000s) | 2017_Act | 2018_Act | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2017-2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| OM&A | 5,628 | 5,754 | 6,352 | 6,522 | 6,694 | 6,694 | 6,694 | 6,694 | 6,694 | 6,694 | 64,420 |
| Depreciation | (71) | (212) | (362) | (516) | (674) | (833) | (991) | (1,149) | (1,308) | (1,466) | (7,580) |
| PILs | (14) | 20 | 45 | 67 | 80 | 85 | 82 | 70 | 51 | 26 | 514 |
| Return | (295) | (613) | (947) | (1,276) | (1,607) | (1,929) | (2,242) | (2,547) | (2,843) | (3,131) | (17,430) |
| **Total Net Impact_Alectra Utilities** | **5,248** | **4,951** | **5,089** | **4,798** | **4,493** | **4,018** | **3,543** | **3,068** | **2,594** | **2,122** | **39,923** |

1. The impact for the HRZ will flow through the ESM for 2017, 2018 and 2019

In Procedural Order No. 3, Alectra Utilities was also directed to consider various treatments for the disposition of the capitalization policy balances in the deferral account, including options involving adjustments to rate base. As part of its submission on October 31, 2018, SEC also proposed the approach of using Account 1576 to adjust rate base. Alectra Utilities has reproduced the table provided by SEC as Table 21.

**Table 21 – Adjustment for Capitalization Policy Impact using Account 1576 (2017 Impact) – SEC Approach**

| Component | BRZ | ERZ | HRZ |
|---|---|---|---|
| Increase (-Decrease) in rate base due to higher (lower) capitalized OM&A | ($1,830,532) | $1,866,041 | $5,398,529 |
| Decrease (-Increase) in rate base due to higher (lower) depreciation | $22,882 | ($23,968) | ($67,482) |
| Net Increase (-Decrease) in rate base and therefore credit (debit) to 1576 | ($1,807,650) | $1,842,072 | $5,331,048 |

This approach ignores two key components of the calculation – PILs and Return on Capital, as identified in Table 20, above. The OEB established Account 1576, Accounting Changes under CGAAP, for distributors to record the financial differences arising as a result of changes to accounting depreciation or capitalization. Account 1576 was intended only as a short-term measure to address the interim deferral of IFRS in 2012 with the expectation of a changeover to IFRS in 2013. This short-term measure was not intended to address special circumstances that arise for post-MAADs distributors. Alectra Utilities proposes a variant to Account 1576 that includes the impact of PILs and Return on Capital. The need for this variation arises as Alectra Utilities is in a rebasing deferral period. As a result, the net impact of the capitalization policy change should include the following items:

- The actual impact on OM&A expenditures in each year following the change in capitalization policy until rebasing;
- The actual impact on depreciation expense over the life of the underlying assets as a result of the increase/decrease in capitalization costs;
- The impact on income tax or PILs; and
- The annual return on the cumulative impact from the annual change in capitalization.

The last two items above must be included in assessing any adjustment to rate base. Alectra Utilities has updated SEC's table to include the impact of PILs and Return on Capital. Consistent with the OEB's policy for Accounts 1575 and 1576, Alectra Utilities proposes that disposition of these account balances be applied through adjustments to the revenue requirement in Alectra Utilities' next rebasing application.

**Table 22 – Adjustment for Capitalization Policy Impact using Account 1576 (2017 Impact) – Alectra Approach**

| Component | BRZ | ERZ | PRZ | HRZ |
|---|---|---|---|---|
| Increase (-Decrease) in rate base due to higher (lower) capitalized OM&A | ($1,830,532) | $1,866,041 | $193,660 | $5,398,529 |
| Decrease (-Increase) in rate base due to higher (lower) depreciation | $22,882 | ($23,968) | ($2,152) | ($67,482) |
| Decrease (-Increase) in rate base due to higher (lower) PILs | $6,095 | ($5,453) | ($408) | ($13,977) |
| Decrease (-Increase) in rate base due to higher (lower) return on capital | $130,252 | ($119,852) | ($11,024) | ($294,572) |
| Net Increase (-Decrease) in rate base and therefore credit (debit) to 1576 | ($1,671,303) | $1,716,767 | $180,076 | $5,022,498 |

1. The impact for the HRZ will flow through the ESM for 2017, 2018 and 2019

**Exhibit 2, Tab 1, Schedule 6**

**Alectra Utilities ESM**

## ALECTRA UTILITIES ESM

The OEB requires consolidating entities that propose to defer rebasing beyond five years to implement an ESM for the period beyond five years, whereby excess earnings are shared with consumers on a 50:50 basis for all earnings that are more than 300 basis points above the consolidated entity's annual ROE. The ESM is designed to protect customers and ensure that they share in any increased benefits from consolidation during the deferred rebasing period.

As part of the MAADs Application that resulted in its formation, Alectra Utilities identified at Exhibit B, Tab 7, Schedule 2, an ESM proposal for years six to ten of the rebasing deferral period that is consistent with the OEB's March 26, 2015 *Report on Rate-Making Associated with Distributor Consolidation*. On December 8, 2016, the OEB issued its Decision and Order in respect of the MAADs Application. In the MAADs Decision, the OEB ordered that Alectra Utilities file plans for the ESM by December 31, 2019.

### ESM Proposal

Earnings in excess of 300 basis points above the OEB's established ROE for the consolidated entity would be divided on a 50/50 basis between Alectra Utilities and its ratepayers. As a consolidated utility that has not rebased, there is no "approved" ROE for Alectra Utilities against which the earnings sharing could be determined. Instead, there are approved ROE's for each rate zone. In this regard, for the purposes of the ESM calculation, the representative approved OEB ROE for Alectra Utilities would be calculated using the weighted average, weighted by the OEB-approved rate base amounts for each RZ (from the most recent OEB-approved rebasing application for each predecessor company) as at the time of Alectra Utilities' formation in 2017.

The ratepayers' share of excess earnings will be credited to a newly proposed variance account, for clearance at the next applicable annual IRM application filing. The recorded amount will be shared with customers of the Enersource, Horizon, PowerStream and Brampton RZs only. For example, if Alectra Utilities' earnings exceed 300 basis points above the regulated ROE in year six post consolidation (2022) it would report the applicable balance in the deferral account as part of its year seven (2023) IRM application. That balance would then be refunded to customers over the twelve months commencing January 1, 2024 (i.e., year eight). For clarity, Alectra Utilities would begin reporting on the ROE outcome for ESM purposes commencing in year seven post consolidation, when audited results for year six are available. The regulatory net income will be calculated, for the purpose of earnings sharing, in the same manner as net income for regulatory purposes under the RRR filings, and in accordance with the *RRR 2.1.5.6 ROE Complete Filing Guide,* issued March 2016. Alectra Utilities expects that it will exclude revenue and expenses that are not otherwise included for regulatory purposes.

**Table 23 – Weighted Average ROE Alectra Utilities**

| | HRZ | BRZ | PRZ | ERZ | Alectra |
|---|---|---|---|---|---|
| OEB-Approved Rate Base ($) | 555,698 | 404,619 | 1,082,805 | 623,498 | 2,666,619 |
| OEB- Approved Return on Equity | 8.98% | 9.30% | 8.78% | 8.93% | **8.94%** |
| Weighting Factor: OEB-Approved Rate Base (%) | 20.84% | 15.17% | 40.61% | 23.38% | 100.00% |

**Exhibit 3, Tab 1, Schedule 1**

**Summary of Requests for Individual Rate Zones**

**SUMMARY OF REQUESTS FOR INDIVIDUAL RATE ZONES**

Alectra Utilities is applying for distribution rates and other charges, pursuant to a Price Cap IR, effective January 1, 2020. This application impacts customers in 17 communities including: the Cities of Hamilton and St. Catharines in the Horizon Utilities RZ; the City of Brampton in the Brampton RZ; the Cities of Barrie, Markham, Vaughan and the Towns of Aurora, Richmond Hill, Alliston, Beeton, Bradford West Gwillimbury, Penetanguishene, Thornton, and Tottenham, in the PowerStream RZ; the City of Mississauga, in the Enersource RZ; and the City of Guelph and the Village of Rockwood, in the Guelph Hydro RZ.

Alectra Utilities has completed the IRM Model for all rate zones and will update the Application to include the 2020 IRM Rate Generator Model ("2020 RGM Model") when published by the OEB. This Application has been prepared in accordance with the updated *Chapter 3 of the Board's Filing Requirements for Electricity Distribution Rate Applications – 2018 Edition for 2019 Rate Applications* (the "Chapter 3 Filing Requirements"), dated July 12, 2018, including the key OEB reference documents listed therein, *the Letter from the Board to Licensed Electricity Distributors re: I. Updated Filing Requirements; and, II. Process for 2019 Incentive Regulation Mechanism ("IRM") Distribution Rate Applications,* dated July 12, 2018.

This Application incorporates, or will incorporate, the following guidelines, reports and policy changes, where appropriate for all rate zones:

- OEB Policy: – *A New Distribution Rate Design for Residential Electricity Customers* (EB-2012-0410) issued April 2, 2015;
- *Conservation and Demand Management Requirement Guidelines for Electricity Distributors* - (EB-2014-0278) issued December 19, 2014;
- *Empirical Research in Support of Incentive Rate-Setting: 2018 Benchmarking Update* for determination of Stretch Factor Assignments for 2019 dated August 23, 2018;
- *Filing Requirements For Electricity Distribution Rate Applications - 2018 Edition for 2019 Rate Applications - Chapter 3 Incentive Rate Setting Applications* issued July 12, 2018 (the "Chapter 3 Filing Requirements");

- *Filing Requirements For Electricity Distribution Rate Applications - 2018 Edition for 2019 Rate Applications - Chapter 2 Cost of Service* issued July 12, 2018;
- *Report of the Board on the Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* ("RRFE") issued October 18, 2012;
- *Guidelines for Electricity Distributor Conservation and Demand Management* (EB-2012-0003) issued April 26, 2012;
- *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative* ("EDDVAR") issued July 31, 2009;
- *Report of the Board on the Updated Policy for the Lost Revenue Adjustment Mechanism ("LRAMVA") Calculation: Lost Revenues and Peak Demand Savings from Conservation and Demand Management Programs issued May 19, 2016;*
- *Revision 4.0 of the Guideline G-2008-0001 – Electricity Distribution Retail Transmission Service Rates, dated June 28, 2012;*
- *Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors – November 21, 2013, corrected December 4, 2013;*
- *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors– July 14, 2008;*
- *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors – September 17, 2008;*
- *Addendum to the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors – January 28, 2009;*
- *Guideline (G-2008-0001) on Retail Transmission Service Rates – October 22, 2008 (Revision 3.0 June 22, 2011 and any subsequent updates);*
- *Chapter 5 of the Filing Requirements for Electricity Transmission and Distribution Applications: Consolidated Distribution System Plan Filing Requirements – July 12, 2018;*

- *Report of the Board on Transition to International Financial Reporting Standards EB-2008-0408 – July 28, 2009;*
- *Addendum to Report of the Board EB-2008-0408 – Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment – June 13, 2011;*
- *Report of the Board on Performance Measurement for Electricity Distributors: A Scorecard Approach – March 5, 2014;*
- *Report of the Board on the New Policy Options for the Funding of Capital Investments: The Advanced Capital Module – September 18, 2014;*
- *Report of the Board on the New Policy for Funding of Capital Investments: Supplemental Report – January 22, 2016; and*
- *Report of the Board on Defining Ontario's Typical Electricity Customer – April 14, 2016.*

**Rate Zone-Specific Relief Sought in This Application**

Alectra Utilities provides a summary of the relief sought in respect of specific rate zones, below.

**<u>Horizon Utilities RZ</u>**

Horizon Utilities filed a Custom Incentive Rate-setting Application (the "Custom IR Application", (EB-2014-0002) with the OEB on April 16, 2014, pursuant to section 78 of the *OEB Act*, (Schedule B), seeking approval for five years of distribution rates effective on January 1 of each year from 2015 to 2019.

Alectra Utilities is now seeking adjustments to 2020 rates for the Horizon Utilities RZ, in accordance with the Settlement Proposal and the Decision and Order on Horizon Utilities' Custom IR Application; and the Decision and Order on the 2016, 2017, 2018 and 2019 Annual Filings, with respect to the Horizon Utilities ESM and CIVA. All other aspects of the Annual Filing for the Horizon Utilities RZ is pursuant to a Price Cap IR. This is Alectra Utiltiies' first Annual Filing under Price Cap IR for the Horizon Utilities RZ.

Alectra Utilities is seeking OEB approval of the following items for the Horizon Utilities RZ:

a. The calculation of the 2017 and 2018 Regulated Return on Equity ("ROE") for the purposes of earnings sharing;

b. The calculation of its 2017 and 2018 capital additions for the purpose of calculating the 2017 entry to the Capital Investment Variance Account;

c. 2020 distribution rates effective January 1, 2020 based on 2019 rates adjusted by the Board's Price Cap Index Adjustment Mechanism formula;

d. The clearance of the balances recorded in Group 1 deferral and variance accounts by means of class-specific rate riders effective January 1, 2020 to December 31, 2020;

e. The clearance of the balance in the 1589 Account RSVA - Global Adjustment attributed to new Class A and new Class B customers as of July 1, 2018, by means of customer-specific bill adjustments for each new Class A and new Class B customer;

f. An adjustment to the retail transmission service rates effective January 1, 2020;

g. Refund of Renewable Generation Connection Rate Protection funding;

h. Disposition of LRAMVA amounts related to CDM activities in 2017 over a one-year period; and

i. Current (i.e., 2019) rates provided in Attachment 4 be declared interim effective January 1, 2020, as necessary, if the preceding approvals cannot be issued by the OEB in time to implement final rates effective January 1, 2020.

**HRZ Efficiency Adjustment**

The Settlement Agreement also included an Efficiency Adjustment which was intended to incent Horizon Utilities to maintain or improve its cohort position. The Efficiency Adjustment was based on the OEB's *Empirical Research in Support of Incentive Rate-Setting: 2013 Benchmarking Update for determination of Stretch Factor Assignments for 2015* dated August 14, 2014 (August 14, 2014 Report). The Efficiency Adjustment applies in the event that Horizon Utilities (or Alectra Utilities in respect of the Horizon RZ) is placed in a less efficient cohort than the "Starting Point" in any year during the Custom IR term.

The August 14, 2014 Report placed Horizon Utilities in Group III among Ontario distributors for the purpose of calculating stretch factors for 2015. The Group III Cohort is therefore the "Starting Point" for the rate plan. The Efficiency Factor is calculated by the difference between the Stretch Factor of the "Starting Point" and the Stretch Factor of the "Ending Point". This Efficiency Factor is multiplied by the given rate year plan revenue requirement to provide a dollar adjustment for the purpose of calculating rates for that year. The Settlement Agreement provides an example of this calculation:

> *"… if Horizon Utilities' Starting Point cohort is Group III and it moves to Group IV (Ending Point) in 2016, the Efficiency Adjustment for 2016 would be determined as (0.30% less 0.45%) * $113,484,693 = $170,227. If Horizon Utilities subsequently returns to the Starting Point cohort, no adjustment is made for that subsequent year. If Horizon Utilities remains in a lower cohort than the Starting Point, there will be an Efficiency Factor adjustment in each year that continues to be true".*

In August 2018, the OEB issued the *Empirical Research in Support of Incentive Rate-Setting: 2017 Benchmarking Update for determination of Stretch Factor Assignments for 2018* dated August 2018 (August 2018 Report), which placed Alectra Utilities in Group III Cohort among Ontario distributors. Alectra Utilities relied on this report to determine whether the Efficiency Adjustment should be made to its 2019 revenue requirement. As described above, Horizon Utilities' Starting Point is Cohort III and in accordance with the August 2018 Report, the Ending Point is also Cohort III. As such, no Efficiency Adjustment was made to the revenue requirement for the 2019 rate year. The HRZ CIR plan terminated at the end of 2019; there is no efficiency adjustment requirement for 2020 and beyond.

**HRZ Service Charge Cost Recovery Study**

The Settlement Agreement further provided for the creation of a deferral account (1508 Sub-account "Special Studies") to record costs in connection with the Service Charge Cost Recovery Study (the "Study"). The purpose of the Study is to consider the extent which the service charges are reflective of the costs of providing the services.

Beginning in 2015, the OEB initiated a comprehensive policy review of miscellaneous rates and charges applied by electricity distributors for specific activities or services they provide to their customers (EB-2015-0304). The OEB indicated that the review will be conducted through a number of phases and components. The first phase currently includes the review of wireline pole attachment charges. In 2017, the OEB announced the next phase which includes the review of energy retail service charges. To date, the OEB has not concluded its review of miscellaneous rate and charges. As part of its 2018 annual rate filing, Alectra Utilities stated that in light of the ongoing comprehensive policy review by the OEB, it might not be taking on the Study given the OEB's review is in line with the intent of the Study as contemplated by the Settlement Agreement.[31]

Alectra Utilities confirms that the Study has not been undertaken and no costs have been recorded in a deferral account created for the purpose of the Study. As such, Alectra Utilities submits that this deferral account should be closed.

## **Brampton RZ**

Alectra Utilities is seeking Board approval for the following in the Brampton RZ:

a. 2020 distribution rates effective January 1, 2020 based on 2019 rates adjusted by the Board's Price Cap Index Adjustment Mechanism formula;

b. The clearance of the balances recorded in Group 1 deferral and variance accounts by means of class-specific rate riders effective January 1, 2020 to December 31, 2020;

c. The clearance of the balance in the 1589 Account RSVA - Global Adjustment attributed to new Class A and new Class B customers as of July 1, 2018, by means of customer-specific bill adjustments for each new Class A and new Class B customer;

d. The calculation of its 2017 and 2018 capitalization policy impact for the purpose of determining the 2017 and 2018 entries to the deferral account;

e. An adjustment to the retail transmission service rates effective January 1, 2020;

f. Recovery of Renewable Generation Connection Rate Protection funding;

[31] EB-2017-0024, 1-VECC-2 Interrogatory Response, October 11, 2017.

g. Disposition of LRAMVA amounts related to CDM activities in 2017 over a one-year period; and

h. Current (i.e., 2019) rates provided in Attachment 5 be declared interim effective January 1, 2020, as necessary, if the preceding approvals cannot be issued by the OEB in time to implement final rates effective January 1, 2020.

**PowerStream RZ**

Alectra Utilities is seeking Board approval for the following in the PowerStream RZ:

a. 2020 distribution rates effective January 1, 2020 based on 2019 rates adjusted by the Board's Price Cap Index Adjustment Mechanism formula;

b. The continuation of the implementation of the new distribution rate design for residential electricity customers;

c. The clearance of the balances recorded in Group 1 deferral and variance accounts by means of class-specific rate riders effective January 1, 2020 to December 31, 2020;

d. The clearance of the balance in the 1589 Account RSVA - Global Adjustment attributed to new Class A and new Class B customers as of July 1, 2018, by means of customer-specific bill adjustments for each new Class A and new Class B customer;

e. The calculation of its 2017 and 2018 capitalization policy impact for the purpose of determining the 2017 and 2018 entries to the deferral account;;

f. An adjustment to the retail transmission service rates effective January 1, 2020;

g. Recovery of Renewable Generation Connection Rate Protection funding;

h. Disposition of LRAMVA amounts related to CDM activities in 2017 over a one-year period; and

i. Current (i.e., 2019) rates provided in Attachment 6 be declared interim effective January 1, 2020, as necessary, if the preceding approvals cannot be issued by the OEB in time to implement final rates effective January 1, 2020.

**Enersource RZ**

Alectra Utilities is seeking Board approval for the following in the Enersource RZ:

a. 2020 distribution rates effective January 1, 2020 based on 2019 rates adjusted by the Board's Price Cap Index Adjustment Mechanism formula;

b. The clearance of the balances recorded in Group 1 deferral and variance accounts by means of class-specific rate riders effective January 1, 2020 to December 31, 2020;

c. The clearance of the balance in the 1589 Account RSVA - Global Adjustment attributed to new Class A and new Class B customers as of July 1, 2018, by means of customer-specific bill adjustments for each new Class A and new Class B customer;

d. The calculation of its 2017 and 2018 capitalization policy impact for the purpose of determining the 2017 and 2018 entries to the deferral account;

e. An adjustment to the retail transmission service rates effective January 1, 2020;

f. Recovery of Renewable Generation Connection Rate Protection funding;

g. Disposition of LRAMVA amounts related to CDM activities in 2017 over a one-year period; and

h. Current (i.e., 2019) rates provided in Attachment 7 be declared interim effective January 1, 2020, as necessary, if the preceding approvals cannot be issued by the OEB in time to implement final rates effective January 1, 2020.

**Guelph Hydro RZ**

Alectra Utilities is seeking Board approval for the following in the Guelph RZ:

a. 2020 distribution rates effective January 1, 2020 based on 2019 rates adjusted by the Board's Price Cap Index Adjustment Mechanism formula;

b. The clearance of the balances recorded in Group 1 deferral and variance accounts by means of class-specific rate riders effective January 1, 2020 to December 31, 2020;

c. The clearance of the balance in the 1589 Account RSVA - Global Adjustment attributed to new Class A and new Class B customers as of July 1, 2018, by means of customer-specific bill adjustments for each new Class A and new Class B customer;

d. An adjustment to the retail transmission service rates effective January 1, 2020;

e. Refund of Renewable Generation Connection Rate Protection funding; and

f. Current (i.e., 2019) rates provided in Attachment 8 be declared interim effective January 1, 2020, as necessary, if the preceding approvals cannot be issued by the OEB in time to implement final rates effective January 1, 2020.

# Exhibit 3, Tab 1, Schedule 2

# Horizon Utilities RZ Earnings Sharing Mechanism

# HORIZON UTILITIES RZ EARNINGS SHARING MECHANISM ("ESM")

## Horizon Utilities RZ 2017 ESM Calculation

Alectra Utilities reports on its results for 2017 for the Horizon Utilities RZ in this annual filing, the third year for which the ESM is in place. The 2017 regulatory net income and ROE have been calculated in accordance with the Settlement Agreement.

Alectra Utilities moved quickly to operate and report as one company in 2017, consistent with the OEB's direction in the MAADs decision. Alectra Utilities is able to track distribution revenue and the majority of other revenues and certain costs by rate zone, however operating costs, general plant, taxes and other costs cannot be attributed to a specific rate zone, and therefore requires an allocation methodology to allocate costs and revenues to rate zones for the purpose of the ESM calculation. The supporting details for the ESM calculation including the related cost category and allocation methodology are provided in sections a to d below.

To determine regulatory net income, rate base and ROE for the Horizon Utilities RZ, total net income was calculated for the Horizon Utilities RZ; this included amounts for Horizon Utilities for the 1 month ending January 31, 2017, and Horizon Utilities RZ's share of Alectra Utilities' audited financials for the 11 months ending December 31, 2017.

The regulatory net income for Horizon Utilities for the 1 month ending January 31, 2017 has been reconciled with the financial statements for Horizon Utilities - 1 month ended January 31, 2017.

Alectra Utilities' 2017 (11 months) regulatory net income reported in RRR 2.1.7 and filed with the OEB has been reconciled with the financial statements for Alectra Utilities - 11 months ended December 31, 2017.

The methodology used to calculate Horizon Utilities RZ's share of Alectra Utilities' 2017 financial data is described further in sections (c) Horizon Utilities RZ 2017 Rate Base and (d) Horizon Utilities RZ 2017 Regulatory Net Income.

In the OEB's Decision in Alectra Utilities' 2018 EDR Application (EB-2017-0024),issued on April 5, 2018 (revised April 6, 2018), the OEB stated that: "*For the remainder of the Custom IR term, the effect on earnings resulting from the change in the capitalization policy will be dealt with through the ESM.*" The treatment of the impact of the capitalization change has evolved during Alectra Utilities' 2018 and 2019 EDR proceedings. During the 2019 EDR Application proceeding

(EB-2018-0016), in PO No. 3, the OEB deferred the capitalization policy issue to Alectra Utilities' 2020 EDR Application. The PO also provided for an oral hearing that was convened on December 5 and 6, 2018 to address the York Region Rapid Transit ("YRRT") Incremental Capital Module ("ICM") project and the Earnings Sharing Mechanism ("ESM") for the Horizon Utilities Rate Zone ("RZ"). Alectra Utilities and the Parties reached a Settlement Agreement on the ESM for the Horizon Utilities RZ. The Parties agreed that the allocation of costs between Alectra Utilities' rate zones to determine the Horizon Utilities RZ ESM for 2017; and the interaction between the calculation and the change in capitalization policy, should be deferred to the 2020 EDR Application proceeding. Further details on the impact of the capitalization policy change, is discussed below.

As directed by the OEB in its Decision[32], the impact of the capitalization policy change has been addressed through the ESM. Alectra Utilities has not adjusted earnings based on Horizon Utilities capitalization policy in place prior to the merger.

**Table 24 – Summary of ESM Calculation – Horizon Utilities RZ**

| 2017 Regulatory ROE for ESM | 2017 Actuals ESM | Annual Filing EB-2016-0077 | Variance |
|---|---|---|---|
| Adjusted Regulatory net income | $ 20,113,167 | $ 18,281,100 | $ 1,832,067 |
| Deemed equity | $ 207,057,276 | $ 208,212,985 | ($ 1,155,709) |
| ROE | 9.714% | 8.780% | 0.934% |
| % Return in excess of approved in rates | | 0.934% | |
| $ Return in excess of approved in rates | | $1,933,538 | |
| Amount payable to rate payers | | $966,769 | |

The regulatory net income for the purposes of earnings sharing result in an achieved ROE of 9.714%, as identified in Table 24 above. Alectra Utilities' approved ROE for the Horizon Utilities RZ for 2017 was 8.78%. Alectra Utilities' incurred earnings are $1,832,067 higher than the 2017 approved ROE with $966,769 to be returned to ratepayers. A detailed calculation of the achieved ROE as compared to the approved ROE is provided in an excel model as Attachment 9.

[32] EB-2017-0024, Decision and Order, dated April 6, 2018, p. 81.

Attachment 9 also provides detailed actual or allocated results by rate zone, including supporting cost of capital calculations and total additions / deductions for tax.

Table 25 below shows the calculation of the 2017 ESM rate riders to refund the ESM amount of $966,769 to ratepayers.

**Table 25 – Proposed Rate Riders to Dispose of Earnings Sharing Amount – Horizon Utilities RZ**

| Rate Class | Total $ | Fixed Rate Rider | Variable Rate Rider | Variable Units |
|---|---|---|---|---|
| RESIDENTIAL | ($ 593,731) | ($ 0.22) | $ 0.0000 | $/kWh |
| GENERAL SERVICE LESS THAN 50 KW | ($ 129,527) | ($ 0.34) | ($ 0.0001) | $/kWh |
| GENERAL SERVICE > 50 KW | ($ 195,681) | ($ 3.16) | ($ 0.0213) | $/kW |
| LARGE USE 1 | ($ 20,857) | ($ 197.51) | ($ 0.0117) | $/kW |
| LARGE USE 2 | ($ 8,693) | ($ 46.71) | ($ 0.0028) | $/kW |
| UNMETERED SCATTERED LOAD | ($ 2,710) | ($ 0.07) | ($ 0.0001) | $/kWh |
| SENTINEL LIGHTING | ($ 265) | ($ 0.05) | ($ 0.1253) | $/kW |
| STREET LIGHTING | ($ 15,305) | ($ 0.02) | ($ 0.0443) | $/kW |
| **Total** | **($ 966,769)** | | | |

The ESM rate rider model is filed as Attachment 10. A live excel version will also be provided as part of this filing.

The 2017 Actual ESM regulatory net income and deemed equity have been adjusted in accordance with the OEB's guidance for 2.1.5.6 and the Settlement Agreement, as discussed below. The approved 2017 Annual Filing EB-2016-0077 amounts are without adjustment.

Alectra Utilities seeks approval for the calculation of the Horizon Utilities RZ's 2017 achieved ROE of 9.714%, net income of $20,113,167, excess earnings of $1,933,538 and amount due to rate payers of $966,769 for the purposes of earnings sharing as identified in Table 25, above.

**(a) Regulatory Net Income for ESM**

Table 26 below shows the calculation of regulatory net income starting with the 2017 regulatory net income for the Horizon Utilities RZ and adjustments required for purposes of the OEB ROE calculation and the Settlement Agreement.

## Table 26 – Calculation of Regulatory Net Income – Horizon Utilities RZ

| | 2017 Actuals | | | Annual Filing |
|---|---|---|---|---|
| 2017 Regulatory ROE | HUC | Alectra | Total | EB-2017-0024 |
| **Regulated net income (loss) per RRR 2.1.7** | **$ 1,325,637** | **$ 77,029,538** | **$ 78,355,174** | **$ 22,974,211** |
| Remove CDM Net income | $ 0 | ($ 949,339) | ($ 949,339) | |
| Remove renewable generation (income) loss | $ 0 | $ 12,468,382 | $ 12,468,382 | |
| Remove merger costs | $ 482,892 | $ 2,032,671 | $ 2,515,563 | |
| Add actual interest cost | $ 642,098 | $ 51,910,112 | $ 52,552,210 | |
| Deduct income tax expense | $ 423,562 | $ 10,501,164 | $ 10,924,726 | |
| Remove share of Joint venture net income | | ($ 559,101) | ($ 559,101) | |
| Deduct other rate zones regulatory net income before interest and taxes | | ($ 121,676,434) | ($ 121,676,434) | |
| **Horizon Rate Zone regulatory net income before interest and taxes** | **$ 2,874,189** | **$ 30,756,993** | **$ 33,631,181** | **$ 22,974,211** |
| Deemed interest expense - short term | | | ($ 364,421) | |
| Deemed interest expense - long term | | | ($ 10,062,656) | |
| **Regulatory Net Income before Tax** | | | **$ 23,204,104** | **$ 22,974,211** |
| Income taxes/PILs - current | | | ($ 2,772,559) | ($ 4,693,111) |
| **Horizon Rate Zone regulatory net income before ESM adjustments** | | | **$ 20,431,545** | **$ 18,281,100** |

| Adjusted Net Income for ESM | 2017 Actuals ESM |
|---|---|
| Regulatory Net income | $ 20,431,545 |
| Add back taxes | $ 2,772,559 |
| Add back 2017 ESM accrual | $ 985,377 |
| Add non-allowable donations (non-LEAF) | $ 3,919 |
| Adjustments for DVAs to get to RRR | $ 0 |
| Remove DVA interest (income) expense | $ 43,834 |
| Adjustment for 2016 ESM actual vs. accrued | $ 33,508 |
| Deduct ROE on Stranded meters | ($ 84,000) |
| Deduct 1/5th of Application costs | ($ 495,385) |
| **Adjusted NIBT for ESM** | **$ 23,691,357** |
| PILS | $ 3,578,190 |
| **Adjusted Net Income for ESM** | **$ 20,113,167** |

The 2017 regulatory net income reported by Alectra Utilities for the Horizon Utilities RZ was $20,431,545, as identified in Table 26. The 2017 regulatory net income is based on RRR MIFRS.

The bottom part of Table 26 shows the adjustments made to the regulatory net income to determine regulatory net income after tax of $20,113,167 reported on the same basis as 2.1.5.6 and for the purposes of earnings sharing.

Adjustments to the regulatory net income reported on the same basis as RRR 2.1.5.6 attributable to the Horizon Utilities RZ, in order to determine regulatory net income for the purposes of earnings sharing, are as follows:

- Exclude the 2017 ESM accrual included in the regulatory net income reported in RRR 2.1.7 and 2.1.5.6;
- Exclude net interest expense on deferral and variance accounts;
- Exclude the 2016 ESM expense recorded in the 2017 regulatory net income reported in RRR 2.1.7 and 2.1.5.6;
- Exclude the Rate of Return on Stranded Meters at the short term debt rate of 1.76%;
- Include one-time costs incurred for Horizon Utilities' Custom IR Application, calculated as one-fifth of $2,476,925 in each of 2015 through 2019; and
- Recalculate PILs to reflect the adjusted net income as a result of any revenue and expense adjustments.

These adjusting revenue and expense items were approved on page 30 of Horizon Utilities' Settlement Agreement for its Custom IR Application.

Alectra Utilities has also made the following adjustment for the Horizon Utilities RZ:

- Included current tax on the stranded meter recovery as approved on page 41 of the Settlement Proposal. Current tax on the stranded meter recovery was included in the calculation of PILs in the Custom IR Application.

Specifically, the 2017 regulatory net income reported in RRR 2.1.7 has been adjusted for:

(i) revenue and expense items prescribed by the OEB for the purposes of determining whether a distributor's performance falls outside of the ±300 basis points deadband; and (ii) revenue and expense items specifically included or excluded for the purposes of earnings sharing.

Regulatory net income for the purposes of determining whether a distributor's performance falls outside of the ±300 basis points deadband is reported in RRR 2.1.5.6. Adjustments to the regulatory net income reported in RRR 2.1.7 in order to determine regulatory net income for RRR 2.1.5.6 are as follows:

- Exclude merger related costs, consistent with the calculation of ROE in Horizon Utilities' Custom IR Application. These costs are also excluded from regulatory net income reported in RRR 2.1.5.6.
- Exclude 2016 ESM costs included in 2017 costs due to differences between the accrual and final amount;
- Exclude net interest revenue/expense on Deferral and Variance Accounts (DVAs). Interest revenues and expenses related to DVAs were not included in the calculation of ROE in Horizon Utilities' Custom IR Application;
- Exclude non-rate regulated items not approved in the distributor's last cost of service application. Alectra Utilities has excluded non-LEAP donations of $3,784 from the regulatory net income reported in RRR 2.1.5.6;
- Calculate the cost of debt based on the deemed debt ratio of 56% long term debt and 4% short term debt; and the Cost of Capital parameters approved in Horizon Utilities' 2017 Annual Filing; and
- PILs shall be recalculated from actual to reflect the adjusted net income as a result of any revenue and expense adjustments. A reconciliation of current income tax is provided in Table 27 below. Additionally, the regulatory net income for the purposes of the ESM calculations incorporates current tax only (i.e. excludes deferred taxes) which is consistent with the PILs calculation in Horizon Utilities' Custom IR Application.

**Table 27 – Calculation of Current Taxes – Horizon Utilities RZ**

| Adjustments | Income before Tax | Current Tax Impact | Tax Rate |
|---|---|---|---|
| Regulatory Net income | $ 23,204,104 | $ 2,772,559 | 11.95% |
| Add back 2017 ESM accrual | $ 985,377 | $ 261,125 | 26.50% |
| Add non-allowable donations (non-LEAF) | $ 3,919 | $ 1,038 | 26.50% |
| Adjustments for DVAs to get to RRR | $ 0 | $ 0 | |
| Adjustments for DVA interest (income) expense | $ 43,834 | $ 11,616 | |
| Adjustment for 2016 ESM actual vs. accrued | $ 33,508 | $ 8,880 | 26.50% |
| Deduct ROE on Stranded meters | ($ 84,000) | ($ 22,260) | 26.50% |
| Record Tax on Stranded Meter Rate Rider as per Custom IR Application | | $ 676,509 | |
| Deduct 1/5th of Application costs | ($ 495,385) | ($ 131,277) | 26.50% |
| **Adjusted NIBT for ESM** | **$ 23,691,357** | **$ 3,578,190** | **15.10%** |

### (b) Deemed Equity for ESM

The calculation of deemed equity used to determine the ROE is 40% of rate base. Table 28 below uses the rate base amount to calculate the deemed short term debt, long term debt and equity based on the deemed debt equity structure underpinning Horizon Utilities 2017 approved distribution rates.

**Table 28 – Calculation of Deemed Debt and Equity – Horizon Utilities RZ**

| Deemed Debt and Equity | % | 2017 Actuals ESM | Annual Filing EB-2016-0077 | Variance |
|---|---|---|---|---|
| Deemed ST Debt | 4.00% | $ 20,705,728 | $ 20,821,299 | ($ 115,571) |
| Deemed LT Debt | 56.00% | $ 289,880,187 | $ 291,498,179 | ($ 1,617,993) |
| Deemed Equity | 40.00% | $ 207,057,276 | $ 208,212,985 | ($ 1,155,709) |
| **Total Rate Base** | 100.00% | **$ 517,643,190** | **$ 520,532,463** | **($ 2,889,273)** |

Rate base excludes stranded meter assets and work-in-progress consistent with Horizon Utilities' 2017 rate application. The calculation of rate base is discussed in the Horizon Utilities RZ Rate Base section, below.

### (c) 2017 Rate Base - Horizon Utilities RZ

The calculation of Horizon Utilities RZ rate base is shown in Table 29 below.

**Table 29 – Calculation of Rate Base – Horizon Utilities RZ**

| Rate Base | 2017 Actuals ESM | Annual Filing EB-2016-0077 | Variance |
|---|---|---|---|
| **Average Net Fixed Assets** | **$ 449,067,999** | **$ 432,973,917** | **$ 16,094,082** |
| Working Capital Allowance: | | | |
| Cost of Power | $ 510,177,988 | $ 667,926,057 | ($ 157,748,069) |
| Controllable expenses | $ 61,281,938 | $ 61,728,494 | ($ 446,556) |
| Working Capital Base | $ 571,459,926 | $ 729,654,551 | ($ 158,194,625) |
| **Working Capital Allowance** | **$ 68,575,191** | **$ 87,558,546** | **($ 18,983,355)** |
| **Rate Base** | **$ 517,643,190** | **$ 520,532,463** | **($ 2,889,273)** |

The average net fixed assets amount is the average of the opening and closing in-service property, plant and equipment ("PP&E"), excluding stranded meters, work-in-progress and non-distribution assets, as summarized in Table 30.

**Table 30 – Calculation of Average Net Fixed Assets – Horizon Utilities RZ**

| Description | January 1, 2017 | December 31, 2017 | Average |
|---|---|---|---|
| Distribution Assets | $ 393,011,067 | $ 422,396,256 | $ 407,703,662 |
| General Plant | $ 43,380,554 | $ 39,348,121 | $ 41,364,337 |
| **Total** | **$ 436,391,621** | **$ 461,744,377** | **$ 449,067,999** |

The January 1, 2017 opening PP&E is equal to the 2016 closing PP&E as filed in the Alectra Utilities' 2018 EDR Application EB-2017-0024.

The December 31, 2017 closing PP&E is derived from Alectra's Fixed Asset Continuity Schedules. Alectra continues to maintain four separate legacy accounting systems including fixed asset records. Distribution plant ("DP") is physically located in the rate zone and at December 31, 2017, the DP in the Horizon Utilities rate zone was $422,396,256.

General plant ("GP") is not identifiable by rate zone and GP assets support the operations of all rate zones. The recording of GP additions in 2017 were recorded in the general ledgers and fixed asset records of the various rate zones based on the legacy system used by the employees processing the transactions and not based on use by rate zone.

The total Alectra Utilities December 31, 2017 GP net book value was allocated to the rate zones based on the ratio of 2016 net book value of general plant for each rate zone to the total. Adjustments were made to remove merger impacts.

Cost of Power ("COP") is the actual amount for the Horizon Utilities RZ. At December 31, 2017, Alectra Utilities had four separate billing systems, one for each rate zone. Alectra Utilities continues to track energy sales and COP by rate zone. Energy Sales and Cost of Power amounts were determined in accordance with the OEB's guidance on the recording of retail settlement variances.

Controllable expenses are equal to the Horizon Utilities RZ's OM&A, consistent with the 2017 rate filing. Horizon Utilities RZ's OM&A is discussed in section (d) below.

### (d) Horizon Utilities RZ 2017 Regulatory Net Income

The Horizon Utilities RZ 2017 regulatory net income is the sum of Horizon Utilities' regulatory net income for the one month ending January 31, 2017 ("stub period") plus its portion of the Alectra Utilities regulatory net income for the 11 months ending December 31, 2017.

Table 31 below summarizes the combination of the stub period plus the Horizon Utilities RZ's share of the Alectra Utilities amounts to arrive at the Horizon Utilities RZ 2017 net income.

Determining the regulatory net income for the Horizon Utilities RZ required a review of the Alectra Utilities financial amounts to identify which items are directly attributable to the rate zones and those that need to be allocated amongst rate zones. This process is described below for each line item contributing to Regulatory net income

**Table 31 – 2017 Regulatory Net Income – Horizon Utilities RZ**

| | 2017 Actual | | |
|---|---|---|---|
| **Regulatory Net Income** | **1 Month ending Jan 31/17** | **11 Months ending Dec 31/17** | **Total** |
| Distribution revenue | $ 9,593,782 | $ 103,901,260 | $ 113,495,042 |
| Other revenue | $ 508,612 | $ 4,791,551 | $ 5,300,164 |
| **Revenue** | **$ 10,102,394** | **$ 108,692,811** | **$ 118,795,206** |
| | | | |
| OM&A | $ 5,266,751 | $ 56,015,186 | $ 61,281,938 |
| Depreciation | $ 1,961,455 | $ 21,920,632 | $ 23,882,087 |
| **Net Income before interest and tax** | **$ 2,874,188** | **$ 30,756,993** | **$ 33,631,181** |
| Deemed interest on ST Debt | $ 30,951 | $ 333,470 | $ 364,421 |
| Deemed interest on LT Debt | $ 854,637 | $ 9,208,020 | $ 10,062,656 |
| **Regulatory Net Income before Tax** | **$ 1,988,601** | **$ 21,215,504** | **$ 23,204,104** |
| PILS | $ 423,562 | $ 2,348,997 | $ 2,772,559 |
| **Regulatory Net income** | **$ 1,565,039** | **$ 18,866,506** | **$ 20,431,545** |

(1) Distribution revenue consists of actual distribution revenues from the Horizon Utilities RZ customers for the entire year.

(2) Other revenue for the stub period is the actual for the Horizon Utilities RZ. Other revenue consists mainly of rate zone specific revenues such as specific service and cost recoveries. For the Alectra Utilities period, the other revenues recorded by each rate zone were reviewed to identify the rate zone specific items and to reallocate the cost recoveries to offset OM&A. Horizon Utilities RZ 2017 rates were based on a reallocation of management fee revenues from other revenue to offset OM&A. The Horizon Utilities RZ-specific other revenues are included in the 11 month amount in Table 31, above.

(3) Operating expenses for the Alectra Utilities period are not identifiable by rate zone. Alectra Utilities OM&A was allocated to the rate zones based on the reported 2014-2016 premerger legacy actual OM&A amounts adjusted to remove transaction costs.

The allocators were further adjusted to reflect that Alectra Utilities OM&A consists of 11 months for the Horizon Utilities, Enersource and PowerStream rate zones but only 10 months for the Brampton rate zone. These allocators and the resulting percent allocation are show in Table 32, below.

**Table 32 – OM&A by Rate Zone Allocators**

| | Enersource | Horizon | Brampton | PowerStream | Total Alectra |
|---|---|---|---|---|---|
| 2014-2016 RRR Average | $56,300,996 | $60,901,688 | $28,658,213 | $86,722,101 | $232,582,998 |
| Adjust to Alectra Overhead capitalization | -$ 2,035,681 | -$ 5,889,304 | $ 2,196,638 | -$ 211,265 | ($5,939,613) |
| **Revised OM&A** | **$54,265,315** | **$55,012,383** | **$30,854,852** | **$86,510,836** | **$226,643,385** |
| **% of total** | 23.94% | 24.27% | 13.61% | 38.17% | 100.00% |
| **Prorate for 2017 part year:** | | | | | |
| Months | 11 | 11 | 10 | 11 | |
| Prorated (Alectra Overhead basis) | $ 49,743,205 | $ 50,428,018 | $ 25,712,376 | $ 79,301,599 | $205,185,199 |
| **% of total** | **24.24%** | **24.58%** | **12.53%** | **38.65%** | **100.0%** |

The Alectra Utilities OM&A for 11 months of 2017 was $233,507,349 which is reflective of the 2017 annual RRR filing and was adjusted to remove non-distribution related amounts. In addition, before the allocation of OM&A to the rate zones, merger costs and specific distribution-related amounts not pertaining to the Horizon Utilities RZ were adjusted, as summarized in Table 33, below

**Table 33 – Adjusted Alectra Utilities OM&A for Allocation to Rate Zones (11 months)**

| Description | Amount |
|---|---|
| Alectra Utilities | $233,507,349 |
| Less net merger OM&A costs | ($ 2,032,671) |
| **Adjusted Alectra Utilities OM&A for allocation to rate zones** | **$231,474,678** |
| Distribution related adjustments for PRZ and ERZ | ($ 3,556,000) |
| **Total for allocation** | $ 227,918,678 |

The adjusted Alectra Utilities OM&A was then allocated to the rate zones, using the allocators from Table 32, resulting in the allocated amounts summarized in Table 34, below.

**Table 34 – Allocation of Alectra Utilities OM&A to Rate Zones**

| LDC/Rate Zone | Alectra 2017 | Allocation % | Allocated Amount | Rate Zone Specific | OM&A by Rate Zone |
|---|---|---|---|---|---|
| Brampton | | 12.53% | $ 28,561,177 | | $ 28,561,177 |
| Enersource | | 24.24% | $ 55,254,500 | $ 1,153,000 | $ 56,407,500 |
| Horizon | | 24.58% | $ 56,015,186 | | $ 56,015,186 |
| PowerStream | | 38.65% | $ 88,087,814 | $ 2,403,000 | $ 90,490,814 |
| Alectra | $ 227,918,678 | | | | $ - |
| **Total** | **$ 227,918,678** | **100.00%** | **$ 227,918,678** | **$ 3,556,000** | **$ 231,474,678** |

(4) Depreciation and amortization is based on the PP&E attributable to the Horizon Utilities RZ as discussed in section (b), above, i.e., actual for the Horizon Utilities RZ for distribution plant for all of 2017, actual for the Horizon Utilities RZ for general plant in the stub period, and an allocation of general plant depreciation expense for the Alectra Utilities period. Derecognition expense relates to distribution plant and is tracked by rate zone; the amounts shown for the Horizon Utilities RZ are actual amounts for the Horizon Utilities RZ. Adjustments were made to remove merger impacts. This is summarized in Table 35, below.

**Table 35 – Horizon Utilities Rate Zone Depreciation Expense**

| Horizon Utilities Rate Zone | Jan 31/17 (1 month) | Dec 31/17 (11 months) | 2017 Total |
|---|---|---|---|
| Distribution Assets | $1,306,460 | $13,924,861 | $15,231,321 |
| General Plant | $589,825 | $6,431,099 | $7,020,923 |
| **subtotal** | **$1,896,285** | **$20,355,959** | **$22,252,244** |
| Derecognition expense | $65,171 | $1,564,672 | $1,629,843 |
| **Total** | **$1,961,455** | **$21,920,632** | **$23,882,087** |

The 2017 general plant depreciation expense for the Alectra Utilities' period of $29,094,654 net of merger adjustment was allocated to the rate zones based on the ratio of each rate zone`s 2016 general plant depreciation expense to the total for all rate zones. This is shown in Table 36, below.

**Table 36 – Alectra Utilities' General Plant Depreciation Allocated to Rate Zones**

| General Plant Rate Zone | Depreciation Dec 31/16 | Alectra Percentage | Depreciation Amount |
|---|---|---|---|
| Horizon Utilities | $7,006,612 | 22.10% | **$ 6,431,099** |
| Enersource | $7,487,110 | 23.62% | $ 6,872,129 |
| Brampton | $2,184,969 | 6.89% | $ 2,005,499 |
| PowerStream | $15,019,619 | 47.38% | $ 13,785,928 |
| **Total** | **$31,698,310** | 100.00% | $ 29,094,654 |

(5) Interest expense is based on the deemed short term and long term debt amounts, discussed above in section (b) at the interest rates underpinning Alectra Utilities' 2017 approved rates for the Horizon Utilities RZ.

(6) Income tax expense

The Horizon Utilities RZ 2017 (11 months) regulatory net income before taxes of $21,215,504 from Table 31 above was adjusted by Horizon Utilities RZ's share of Alectra Utilities adjustments for tax resulting in taxable income of $9,063,209. Using the tax rate of 26.5% and actual tax credits of $52,573 related to the Horizon Utilities RZ results in current income tax expense of $2,348,997 as shown in Table 37, below.

**Table 37 – Adjustments to Determine Horizon Utilities Rate Zone Taxable Income**

| Horizon Rate Zone - Alectra period | Actual | EB-2016-0077 |
|---|---|---|
| Regulatory net income before tax | $ 21,215,504 | $ 18,281,100 |
| Net additions (deductions) for tax | ($ 12,152,295) | ($ 4,675,679) |
| Taxable income | $ 9,063,209 | $ 13,605,421 |
| Rate rate | 26.50% | 26.50% |
| Income taxes | $ 2,401,750 | $ 3,605,437 |
| tax credits | ($ 52,753) | ($ 156,000) |
| Current taxes payable | $ 2,348,997 | $ 3,449,437 |
| PILs Gross-up | $ 0 | $ 1,243,674 |
| Income taxes | $ 2,348,997 | $ 4,693,111 |

The Horizon Utilities RZ income tax expense for the Alectra Utiltiies period shown in Table 37 was added to the income tax expense for the stub period ending Jan 31, 2017, to determine the total Horizon Utilities RZ 2017 income tax expense, as shown in Table 31, above.

**<u>Horizon Utilities RZ 2018 ESM Calculation</u>**

Alectra Utilities reports on its results for 2018 for the Horizon Utilities RZ in this Application, the fourth year for which the ESM is in place. The 2018 regulatory net income and ROE have been calculated in accordance with the Settlement Agreement.

Alectra Utilities moved quickly to operate and report as one company in 2017, consistent with the OEB's direction in the MAADs decision. Alectra Utilities is able to track distribution revenue, other revenues and certain costs by rate zone, however operating costs, general plant, taxes and other costs cannot be attributed to a specific rate zone, and therefore requires an allocation methodology to allocate costs and revenues to rate zones for the purpose of the ESM calculation. The supporting details for the ESM calculation including the related cost category and allocation methodology are provided in sections a) to d), below.

In order to determine regulatory net income, rate base and ROE for the Horizon Utilities RZ, total net income was calculated for the Horizon Utilities RZ's share of Alectra Utilities' audited financials for the 12 months ending December 31, 2018.

Alectra Utilities' 2018 regulatory net income reported in RRR 2.1.7 and filed with the OEB has been reconciled with the financial statements for Alectra Utilities - 12 months ended December 31, 2018.

The methodology used to calculate Horizon Utilities RZ's share of Alectra Utilities' 2018 financial data is described further in sections (c) Horizon Utilities RZ 2018 Rate Base and (d) Horizon Utilities RZ 2018 Regulatory Net Income.

In the OEB's Decision in Alectra Utilities' 2018 EDR Application (EB-2017-0024),issued on April 5, 2018 (revised April 6, 2018), the OEB stated that: "*For the remainder of the Custom IR term, the effect on earnings resulting from the change in the capitalization policy will be dealt with through the ESM.*

As directed by the Board in its Decision, the impact of the capitalization policy change has been addressed through the ESM.

**Table 38 – Summary of ESM Calculation – Horizon Utilities RZ**

| 2018 Regulatory ROE for ESM | 2018 Actuals ESM | Annual Filing EB-2017-0024 | Variance |
|---|---|---|---|
| Adjusted Regulatory net income | $ 17,887,010 | $ 19,051,629 | ($ 1,164,619) |
| Deemed equity | $ 214,920,389 | $ 211,684,768 | $ 3,235,621 |
| ROE | 8.323% | 9.000% | -0.677% |
| % Return in excess of approved in rates | | -0.677% | |
| $ Return in excess of approved in rates | | $0 | |
| Amount payable to rate payers | | $0 | |

The regulatory net income for the purposes of earnings sharing result in an achieved ROE of 8.32%, as identified in Table 38 above. Alectra Utilities' approved ROE for the Horizon Utilities RZ for 2018 was 9.00%. Alectra Utilities' incurred earnings are lower than the 2018 approved ROE as a result the ESM has not been triggered and no amount is to be returned to ratepayers. A detailed calculation of the achieved ROE as compared to the approved ROE is provided in an excel model as Attachment 11. Attachment 11 also provides detailed actual or allocated results by rate zone, including supporting cost of capital calculations and total additions / deductions for tax.

The 2018 actual ESM regulatory net income and deemed equity have been adjusted in accordance with the OEB's guidance for 2.1.5.6 and the Settlement Agreement, as discussed below. The approved 2018 Annual Filing EB-2017-0024 amounts are without adjustment.

Alectra Utilities seeks approval for the calculation of the Horizon Utilities RZ's 2018 achieved ROE of 8.32%, net income of $17,887,010 which results in under earnings of $1,164,619 in comparison to the approved ROE.

### (e) Regulatory Net Income for ESM

Table 39 below shows the calculation of regulatory net income starting with the 2018 regulatory net income for the Horizon Utilities RZ and adjustments required for purposes of the OEB ROE calculation and the Settlement Agreement.

**Table 39 – Calculation of Regulatory Net Income – Horizon Utilities RZ**

| 2018 Regulatory ROE | Alectra | Total | Annual Filing EB-2017-0024 |
|---|---|---|---|
| **Regulated net income (loss) per RRR 2.1.7** | **$ 135,928,739** | **$ 135,928,739** | |
| Remove CDM net income | ($ 13,646,000) | ($ 13,646,000) | |
| Remove renewable generation, water & Collus gain on sale net income | ($ 4,785,165) | ($ 4,785,165) | |
| Add back net merger savings | ($ 25,225,862) | ($ 25,225,862) | |
| Add actual interest cost | $ 61,804,399 | $ 61,804,399 | |
| Deduct income tax expense | $ 20,251,616 | $ 20,251,616 | |
| Deduct other rate zones regulatory net income before interest and taxes | ($ 143,054,276) | ($ 143,054,276) | |
| **Horizon Rate Zone regulatory net income before interest and taxes** | **$ 31,273,451** | **$ 31,273,451** | |
| Deemed interest expense - short term | | ($ 492,168) | |
| Deemed interest expense - long term | | ($ 10,899,162) | |
| **Regulatory Net Income before Tax** | | **$ 19,882,121** | **$ 22,217,925** |
| Income taxes/PILs - current | | $ 1,953,181 | $ 3,166,296 |
| **Horizon Rate Zone regulatory net income before ESM adjustments** | | **$ 17,928,940** | **$ 19,051,629** |

| **Adjusted Net Income for ESM** | **2018 Actuals ESM** |
|---|---|
| Regulatory Net income | $ 17,928,940 |
| Add back taxes | $ 1,953,181 |
| Add back 2018 ESM accrual | $ 0 |
| Add non-allowable donations (non-LEAP) | $ 0 |
| Adjust DVA interest (income) expense | $ 438,337 |
| Deduct 1/5th of Application costs | ($ 495,385) |
| **Adjusted NIBT for ESM** | **$ 19,825,073** |
| PILS | $ 1,938,063 |
| **Adjusted Net Income for ESM** | **$ 17,887,010** |

The 2018 regulatory net income reported by Alectra Utilities for the Horizon Utilities RZ was $17,928,940, as identified in Table 39. The 2018 regulatory net income is based on RRR MIFRS.

The bottom part of Table 39 shows the adjustments made to the regulatory net income to determine regulatory net income after tax of $17,887,010 reported on the same basis as 2.1.5.6 and for the purposes of earnings sharing.

Adjustments to the regulatory net income reported on the same basis as RRR 2.1.5.6 attributable to the Horizon Utilities RZ, in order to determine regulatory net income for the purposes of earnings sharing, are as follows:

- Exclude the 2018 ESM accrual included in the regulatory net income reported in RRR 2.1.7 and 2.1.5.6;
- Exclude net interest expense on deferral and variance accounts;
- Exclude the 2017 ESM expense recorded in the 2018 regulatory net income reported in RRR 2.1.7 and 2.1.5.6;
- Include one-time costs incurred for Horizon Utilities' Custom IR Application, calculated as one-fifth of $2,476,925 in each of 2015 through 2019; and
- Recalculate PILs to reflect the adjusted net income as a result of any revenue and expense adjustments.

These adjusting revenue and expense items were approved on page 30 of Horizon Utilities' Settlement Agreement for its Custom IR Application.

The recovery of return on stranded meters ended on December 31, 2017 and as a result no corresponding adjustments were required for the purposes of the ESM calculation.

Alectra Utilities has adjusted the 2018 regulatory net income reported in RRR 2.1.7 for the following:

(i) revenue and expense items prescribed by the OEB for the purposes of determining whether a distributor's performance falls outside of the ±300 basis points deadband; and
(ii) revenue and expense items specifically included or excluded for the purposes of earnings sharing.

Regulatory net income for the purposes of determining whether a distributor's performance falls outside of the ±300 basis points deadband is reported in RRR 2.1.5.6. Adjustments to the regulatory net income reported in RRR 2.1.7 in order to determine regulatory net income for RRR 2.1.5.6 are as follows:

- Exclude merger related costs, consistent with the calculation of ROE in Horizon Utilities' Custom IR Application. These costs are also excluded from regulatory net income reported in RRR 2.1.5.6.

- Exclude 2017 ESM costs included in 2018 costs due to differences between the accrual and final amount;
- Exclude net interest revenue/expense on Deferral and Variance Accounts ("DVAs"). Interest revenues and expenses related to DVAs were not included in the calculation of ROE in Horizon Utilities' Custom IR Application;
- Exclude non-rate regulated items not approved in the distributor's last cost of service application;
- Calculate the cost of debt based on the deemed debt ratio of 56% long term debt and 4% short term debt; and the Cost of Capital parameters approved in Horizon Utilities' 2018 Annual Filing; and
- PILs shall be recalculated from actual to reflect the adjusted net income as a result of any revenue and expense adjustments. A reconciliation of current income tax is provided in Table 40 below. Additionally, the regulatory net income for the purposes of the ESM calculations incorporates current tax only (i.e. excludes deferred taxes) which is consistent with the PILs calculation in Horizon Utilities' Custom IR Application.

**Table 40 – Calculation of Current Taxes – Horizon Utilities RZ**

| Adjustments | Income before Tax | Current Tax Impact | Tax Rate |
|---|---|---|---|
| Regulatory Net income | $ 19,882,121 | $ 1,953,181 | 9.82% |
| Add back 2018 ESM accrual | $ 0 | $ 0 | |
| Add non-allowable donations (non-LEAP) | $ 0 | $ 0 | |
| Adjustments for DVA interest (income) expense | $ 438,337 | $ 116,159 | |
| Adjustment for 2017 ESM actual vs. accrued | $ 0 | $ 0 | |
| Deduct 1/5th of Application costs | ($ 495,385) | ($ 131,277) | 26.50% |
| **Adjusted NIBT for ESM** | **$ 19,825,073** | **$ 1,938,063** | **9.78%** |

### (f) Deemed Equity for ESM

The calculation of deemed equity used to determine the ROE is 40% of rate base. Table 41 below uses the rate base amount to calculate the deemed short term debt, long term debt and equity based on the deemed debt equity structure underpinning Horizon Utilities 2018 approved distribution rates.

**Table 41 – Calculation of Deemed Debt and Equity – Horizon Utilities RZ**

| Deemed Debt and Equity | % | 2018 Actual ESM | Annual Filing EB-2017-0024 | Variance |
|---|---|---|---|---|
| Deemed ST Debt | 4.00% | $ 21,492,039 | $ 21,168,477 | $ 323,562 |
| Deemed LT Debt | 56.00% | $ 300,888,545 | $ 296,358,675 | $ 4,529,870 |
| Deemed Equity | 40.00% | $ 214,920,389 | $ 211,684,768 | $ 3,235,621 |
| **Total Rate Base** | 100.00% | **$ 537,300,973** | **$ 529,211,920** | **$ 8,089,053** |

Rate base is consistent with Horizon Utilities' 2018 rate application. The calculation of rate base is discussed in the Horizon Utilities RZ Rate Base section, below.

### (g) 2018 Rate Base - Horizon Utilities RZ

The calculation of Horizon Utilities RZ rate base is shown in Table 42, below.

**Table 42 – Calculation of Rate Base – Horizon Utilities RZ**

| Rate Base | 2018 Actual ESM | Annual Filing EB-2017-0024 | Variance |
|---|---|---|---|
| **Average Net Fixed Assets** | **$ 470,376,680** | **$ 453,910,872** | **$ 16,465,808** |
| Working Capital Allowance: | | | |
| Cost of Power | $ 494,866,319 | $ 564,872,280 | **($ 70,005,961)** |
| Controllable expenses | $ 62,836,129 | $ 62,636,457 | **$ 199,672** |
| Working Capital Base | $ 557,702,448 | $ 627,508,737 | **($ 69,806,289)** |
| **Working Capital Allowance** | **$ 66,924,294** | **$ 75,301,048** | **($ 8,376,755)** |
| **Rate Base** | **$ 537,300,973** | **$ 529,211,920** | **$ 8,089,053** |

The average net fixed assets amount is the average of the opening and closing in-service property, plant and equipment ("PP&E"), work-in-progress and non-distribution assets, as summarized in Table 43.

**Table 43 – Calculation of Average Net Fixed Assets – Horizon Utilities RZ**

| Description | Jan 1/18 | Dec 31/18 | Average |
|---|---|---|---|
| Distribution Assets | $ 422,396,256 | $ 435,596,371 | $ 428,996,313 |
| General Plant | $ 39,348,121 | $ 43,412,612 | $ 41,380,366 |
| **Total** | **$ 461,744,377** | **$ 479,008,982** | **$ 470,376,680** |

The January 1, 2018 opening PP&E is equal to the 2017 closing PP&E as filed in the Alectra Utilities' 2019 EDR Application EB-2018-0018.

The December 31, 2018 closing PP&E is derived from Alectra's Fixed Asset Continuity Schedules. Alectra continues to maintain four separate legacy accounting systems including fixed asset records. Distribution plant ("DP") is physically located in the rate zone and at December 31, 2018, the DP in the Horizon Utilities rate zone was $435,596,371.

General plant ("GP") is not identifiable by rate zone and GP assets support the operations of all rate zones. The recording of GP additions in 2018 were recorded in the general ledgers and fixed asset records of the various rate zones based on the legacy system used by the employees processing the transactions and not based on use by rate zone.

The total Alectra Utilities December 31, 2018 GP net book value was allocated to the rate zones based on the ratio of 2016 net book value of general plant for each rate zone to the total. Adjustments were made to remove merger impacts.

Cost of Power ("COP") is the actual amount for the Horizon Utilities RZ. At December 31, 2018, Alectra Utilties had four separate billing systems, one for each rate zone. Alectra Utilities continues to track energy sales and COP by rate zone. Energy Sales and Cost of Power amounts were determined in accordance with the OEB's guidance on the recording of retail settlement variances.

Controllable expenses are equal to the Horizon Utilities RZ's OM&A consistent with the 2018 rate filing. Horizon Utilities RZ's OM&A is discussed in section (d) below.

### (h) Horizon Utilities RZ 2018 Regulatory Net Income

The Horizon Utilities RZ 2018 regulatory net income is summarized in Table 44 below. Determining the regulatory net income for the Horizon Utilities RZ required a review of the Alectra Utilities financial amounts to identify which items are directly attributable to the rate zones and those that need to be allocated amongst rate zones. This process is described below for each line item contributing to Regulatory net income

**Table 44 – 2018 Regulatory Net Income – Horizon Utilities RZ**

| Regulatory Net Income | 2018 Actual |
|---|---|
| Distribution revenue | $ 114,566,462 |
| Other revenue | $ 4,908,678 |
| **Revenue** | **$ 119,475,140** |
| | |
| OM&A | $ 62,836,129 |
| Depreciation | $ 25,365,560 |
| Deemed interest on ST Debt | $ 492,168 |
| Deemed interest on LT Debt | $ 10,899,162 |
| **Total expenses** | **$ 99,593,019** |
| **Regulatory Net Income before Tax** | **$ 19,882,121** |
| PILS | $ 1,953,181 |
| **Regulatory Net income** | **$ 17,928,940** |

(7) Distribution revenue consists of actual distribution revenues from the Horizon Utilities RZ customers for the entire year. Distribution revenue excludes any prior period ESM accruals.

(8) Other revenue for the stub period is the actual for the Horizon Utilities RZ. Other revenue consists mainly of rate zone specific revenues such as specific service and cost recoveries. Other revenues recorded by each rate zone were reviewed to identify the rate zone specific items and to reallocate the cost recoveries to offset OM&A.

(9) Operating expenses for the Alectra Utilities period are not identifiable by rate zone. Alectra Utilities OM&A was allocated to the rate zones based on the reported 2014-2016 premerger legacy actual OM&A amounts adjusted to remove transaction costs. These allocators and the resulting percent allocation are show in Table 45, below.

**Table 45 – OM&A by Rate Zone Allocators**

| | Enersource | Horizon | Brampton | PowerStream | Total Alectra |
|---|---|---|---|---|---|
| 2014-2016 RRR Average | $56,300,996 | $60,901,688 | $28,658,213 | $86,722,101 | $232,582,998 |
| Adjust to Alectra Overhead capitalization | ($1,711,518) | ($5,242,737) | $1,609,690 | ($409,708) | ($5,754,273) |
| **Revised OM&A** | **$54,589,478** | **$55,658,951** | **$30,267,903** | **$86,312,393** | **$226,828,725** |
| **% of total** | 24.07% | 24.54% | 13.34% | 38.05% | 100.00% |

The Alectra Utilities OM&A for 2018 was $232,057,952 which is reflective of the 2018 annual RRR filing and was adjusted to remove non-distribution related amounts. In addition, before the allocation of OM&A to the rate zones, merger costs were adjusted, as summarized in Table 46, below.

**Table 46 – Alectra Utilities OM&A for Allocation to Rate Zones**

| Description | Amount |
|---|---|
| Alectra Utilities | $ 232,057,952 |
| Plus net merger OM&A savings | $ 24,020,161 |
| **Adjusted Alectra OM&A for allocation to rate zones** | **$ 256,078,113** |

The adjusted Alectra Utilities OM&A was then allocated to the rate zones, using the allocators from Table 45, resulting in the allocated amounts summarized in Table 47, below.

**Table 47 – Allocation of Alectra Utilities OM&A to Rate Zones**

| LDC/Rate Zone | Alectra 2018 | Allocation % | OM&A by Rate Zone |
|---|---|---|---|
| Brampton | | 13.34394633% | $ 34,170,926 |
| Enersource | | 24.06638663% | $ 61,628,749 |
| Horizon | | 24.53787570% | $ 62,836,129 |
| PowerStream | | 38.05179134% | $ 97,442,309 |
| Alectra | $ 256,078,113 | | $ - |
| **Total** | **$ 256,078,113** | **100.00%** | **$ 256,078,113** |

(10) Depreciation and amortization is based on the PP&E attributable to the Horizon Utilities RZ as discussed in section (b), above, i.e., actual for the Horizon Utilities RZ for distribution plant for all of 2018, actual for the Horizon Utilities RZ for general plant in the stub period, and an allocation of general plant depreciation expense for the Alectra Utilities period. Derecognition expense relates to distribution plant and is tracked by rate zone; the amounts shown for the Horizon Utilities RZ are actual amounts for the Horizon Utilities RZ. Adjustments were made to remove merger impacts. This is summarized in Table 48, below.

**Table 48 – Horizon Utilities Rate Zone Depreciation Expense**

| Horizon Rate Zone | 2018 Total |
|---|---|
| Distribution Assets | $16,034,721 |
| General Plant | $6,935,435 |
| **subtotal** | **$22,970,156** |
| Derecognition expense | $2,395,404 |
| **Total** | **$25,365,560** |

The 2018 general plant depreciation expense for the Alectra Utilities' period of $31,376,300 net of merger adjustment was allocated to the rate zones based on the ratio of each rate zone`s 2016 general plant depreciation expense to the total for all rate zones. This is shown in Table 49, below.

**Table 49 – Alectra Utilities' General Plant Depreciation Allocated to Rate Zones**

| General Plant Rate Zone | 2016 Depreciation Amount | Allocation Percentage | 2018 Depreciation Amount |
|---|---|---|---|
| Horizon | $7,006,612 | 22.10% | **$ 6,935,435** |
| Enersource | $7,487,110 | 23.62% | $ 7,411,051 |
| Brampton | $2,184,969 | 6.89% | $ 2,162,773 |
| PowerStream | $15,019,619 | 47.38% | $ 14,867,040 |
| **Total** | **$31,698,310** | 100.00% | $ 31,376,300 |

(11) Interest expense is based on the deemed short term and long term debt amounts, discussed above in section (b) at the interest rates underpinning Alectra Utilities' 2018 approved rates for the Horizon Utilities RZ.

(12) Income tax expense

The Horizon Utilities RZ 2018 regulatory net income before taxes of $19,882,121 from Table 44 above was adjusted by Horizon Utilities RZ's share of Alectra Utilities adjustments for tax resulting in taxable income of $8,032,610. Using the tax rate of 26.5% and actual tax credits of $175,461 related to the Horizon Utilities RZ results in current income tax expense of $1,953,181 as shown in Table 50, below.

**Table 50 – Adjustments to Determine Horizon Utilities Rate Zone Taxable Income**

| Horizon Rate Zone - Alectra period | 2018 Actual | Annual Filing EB-2017-0024 |
|---|---|---|
| Regulatory net income before tax | $ 19,882,121 | $ 19,051,629 |
| Net additions (deductions) for tax | ($ 11,849,511) | ($ 9,552,657) |
| Taxable income | $ 8,032,610 | $ 9,498,972 |
| Rate rate | 26.50% | 26.50% |
| Income taxes | $ 2,128,642 | $ 2,517,228 |
| tax credits | ($ 175,461) | ($ 190,000) |
| Current taxes payable | $ 1,953,181 | $ 2,327,228 |
| PILs Gross-up | $ 0 | $ 839,068 |
| Income taxes | $ 1,953,181 | $ 3,166,296 |

**Exhibit 3, Tab 1, Schedule 3**

**Horizon Utilities RZ Earnings Capital Investment Variance Account**

**HORIZON UTILITIES RZ CAPITAL INVESTMENT VARIANCE ACCOUNT**

Horizon Utilities' 2015 - 2019 Custom IR Settlement Agreement provided for the introduction of a deferral account (1508 Sub-account "Capital Additions Variance Account", referred to in the Settlement Agreement as the Capital Investment Variance Account ("CIVA")) to refund to ratepayers any difference in the revenue requirement should in-service capital additions be lower than, or the pacing of capital additions be slower than, forecast over the 2015-2019 period.

The Parties agreed to track variances in the revenue requirement due to variances in the capital budget. Over the term of the plan, if Horizon Utilities spends less than its capital forecast, the reduced revenue requirement impact of this will be returned to customers. The Parties agreed, and the OEB approved, that the CIVA balance would be disposed of following the end of the five-year Custom IR term, if applicable.

Alectra Utilities reports the capital additions for 2017 and 2018 for the Horizon Utilities RZ in this Annual Filing. In the 2019 EDR Application Decision (EB-2018-0016), the OEB stated that: *"The change in the capitalization policy increases the in-service capital additions for the same amount of capital work to implement the strategy. The question for the OEB is whether the capital additions for the CIVA account should be based on the capitalization policy in place at the time the Custom IR framework for the Horizon rate zone was approved, or the new post-merger capitalization policy for Alectra Utilities."* Further, consistent to its Decision on the impact of the capitalization policy change on the ESM for Horizon Utilities, the OEB stated: *"The OEB finds that it is appropriate to defer consideration of the actual 2017 capital additions to be used for the final computation of the CIVA account until the application for 2020 rates. The OEB has previously determined that other issues related to the change in capitalization policy will be heard in the same 2020 rate proceeding."*

In the 2019 Annual Filing, Alectra Utilities reported the capital additions for 2017 for the Horizon Utilities RZ. Alectra Utilities' 2017 actual capital additions in the Horizon Utilities RZ were $52,393,539, $6,767,425 higher than the capital additions of $45,626,114 forecast in its Custom IR Application. In this Application, Alectra Utilities reports the capital additions for 2018. Alectra Utilities' 2018 actual capital additions in the Horizon RZ were $44,634,762, $2,507,742 lower than the capital additions of $47,142,504 forecasted in its Custom IR Application. The capital additions presented for 2017 and 2018 are inclusive of the capitalization policy change that was a result of the consolidation that formed Alectra Utiltiies. Alectra Utiltiies is applying the impact of the capitalization policy change consistently, both in its computation of the Horizon Utilities RZ ESM per the OEB's decision in the 2018 EDR Application (EB-2017-0024), and in its statement of capital additions in 2017 and 2018.

**Table 51 – 2015 to 2018 Capital Additions - Actual vs. Custom IR Application**

| Capital Additions | Actual | Custom IR Application (EB-2014-0002) | Variance | EDR Application |
|---|---|---|---|---|
| 2015 | $ 46,643,216 | $ 38,314,524 | $ 8,328,692 | EB-2016-0077 |
| 2016 | $ 44,295,265 | $ 41,147,533 | $ 3,147,732 | EB-2017-0024 |
| 2017 | $ 52,393,539 | $ 45,626,114 | $ 6,767,425 | EB-2018-0016 |
| 2018 | $ 44,634,762 | $ 47,142,504 | ($ 2,507,742) | EB-2019-0018 |
| **Cumulative total** | **$ 187,966,782** | **$ 172,230,675** | **$ 15,736,107** | |

Forecasted capital additions for 2015 to 2018 of $38,314,524, $41,147,533, $45,626,114 and $47,142,504 were approved by the Board in Horizon Utilities' Settlement Agreement for its Custom IR Application (refer to Settlement Table 9, page 33).

Horizon Utilities' actual 2015 capital additions of $46,643,216 were approved by the Board in EB-2016-0077 and actual 2016 capital additions of $44,295,265 were approved by the Board in EB-2017-0024.

As shown in Table 51 above, the Horizon Utilities RZ capital additions for the years 2015 to 2018 exceed the corresponding amounts approved in its Custom IR Application (EB-2014-0002). Therefore, Alectra Utilities has not established, or made an entry to, the 1508 Sub-account "Capital Investment Variance Account" ("CIVA") for the Horizon Utilities RZ.

Alectra Utilities seeks approval of 2017 and 2018 capital additions for the purpose of calculating the entry to the CIVA. Table 52 below presents the 2017 capital additions by rate zone for the legacy stub periods plus the Alectra Utilities total in-service capital additions of $255,879,336, that along with work-in-progress, forms the additions reported in its RRR 2.1.5.2 Capital filed April 30, 2018.

**Table 52 – Alectra Utilities 2017 Actual Capital Additions by Rate Zone**

| | Brampton | Enersource | Horizon Utilities | PowerStream | Alectra | Total |
|---|---|---|---|---|---|---|
| **1) Distribution Plant (DP)** | | | | | | |
| 2017 pre-Alectra | ($ 185,718) | $ 162,363 | $ 1,239,563 | $ 12,014,175 | | $ 13,230,383 |
| 2017 Alectra | $ 24,064,276 | $ 52,572,809 | $ 45,429,350 | $ 103,658,057 | $ 225,724,491 | $ 225,724,491 |
| **Total DP additions** | **$ 23,878,558** | **$ 52,735,171** | **$ 46,668,913** | **$ 115,672,232** | **$ 225,724,491** | **$ 238,954,874** |
| **2) General Plant (GP)** | | | | | | |
| 2017 pre-Alectra | $ 66,073 | $ 162,363 | $ 212,809 | $ 891,073 | | $ 1,332,317 |
| 2017 Alectra | $ 4,589,806 | $ 8,463,535 | $ 5,511,817 | $ 11,589,687 | $ 30,154,845 | $ 30,154,845 |
| **Total GP additions** | **$ 4,655,878** | **$ 8,625,898** | **$ 5,724,626** | **$ 12,480,760** | **$ 30,154,845** | **$ 31,487,162** |
| **Total new capital additions** | **$ 28,534,436** | **$ 61,361,069** | **$ 52,393,539** | **$ 128,152,992** | **$ 255,879,336** | **$ 270,442,036** |

Table 53 below presents the 2018 capital additions by rate zone, that along with work-in-progress, forms the additions reported in its RRR 2.1.5.2 Capital filed April 30, 2019.

**Table 53 – Alectra Utilities 2018 Actual Capital Additions by Rate Zone**

| Horizon Utilities Rate Zone | Brampton | Enersource | Horizon | PowerStream | Alectra | Total |
|---|---|---|---|---|---|---|
| 1) Distribution Plant (DP) | $ 26,859,709 | $ 54,124,769 | $ 37,816,078 | $ 90,508,540 | | $ 209,309,096 |
| 2) General Plant (GP) | | | | | $ 57,924,202 | $ 57,924,202 |
| **Total new capital additions** | **$ 26,859,709** | **$ 54,124,769** | **$ 37,816,078** | **$ 90,508,540** | **$ 57,924,202** | **$ 267,233,298** |

Capital additions consist of distribution system plant and general plant additions. Distribution plant is identifiable and tracked by rate zone as these assets are located in and serve a specific rate zone.

General plant consists mainly of facilities, computers, software, office equipment and fleet. These assets support the overall distribution business rather than a particular rate zone.

For purposes of the Alectra Utilities CIVA calculation for the Horizon Utilities RZ, it is necessary to allocate the general plant additions to the rate zones. The purpose of general plant is to support the overall business, thus general plant should be allocated to the rate zones based on the proportion each represents of the overall distribution business. Alectra Utilities has used the 2016 rate base from 2016 ROE filings by the legacy utilities as the allocator that represents the proportion each rate zone is of the total distribution business. This is summarized in Table 54 below.

**Table 54 – Rate Zone Proportions based on 2016 Rate Base**

| | Brampton | Enersource | Horizon | PowerStream | Total |
|---|---|---|---|---|---|
| Rate Base from ROE filing | $ 421,744,471 | $ 777,690,672 | $ 506,465,550 | $ 1,064,944,076 | $ 2,770,844,769 |
| Proportion | 15.2% | 28.1% | 18.3% | 38.4% | 100.0% |

Alectra Utilities' 2017 and 2018 capital additions for the Horizon Utilities RZ (net of capital contributions) are summarized in Tables 55 and 56, below. These consist of the directly identifiable distribution plant additions and the general plant additions including the Alectra Utilities additions allocated to the Horizon Utilities RZ.

**Table 55 – Horizon Utilities RZ 2017 Capital Additions**

| Horizon Utilities Rate zone | Capital Additions |
|---|---|
| **DP capital additions** | |
| Jan 1- 31, 2017 | $ 1,239,563 |
| Feb 1 - Dec 31, 2017 | $ 45,429,350 |
| **Total DP additions** | **$ 46,668,913** |
| GP capital additions - January 2017 | $ 212,809 |
| Share of Alectra GP additions | $ 5,511,817 |
| **Total GP additions** | **$ 5,724,626** |
| **Total capital additions** | **$52,393,539** |

**Table 56 – Horizon Utilities RZ 2018 Capital Additions**

| Horizon Utilities Rate Zone | Capital Additions |
|---|---|
| DP capital additions | |
| Jan 1- Dec 31, 2018 | $ 37,816,078 |
| **Total DP additions** | **$ 37,816,078** |
| Share of Alectra GP additions | $ 6,818,684 |
| **Total GP additions** | **$ 6,818,684** |
| **Total capital additions** | **$ 44,634,762** |

As discussed above, based on the OEB's Decision on Alectra Utilities' 2018 rate application (EB-2017-0046), there has been no adjustment for the change to Alectra Utilities capitalization policy.

Alectra Utilities general plant additions have been allocated to the Horizon Utilities RZ in the amount of $5,511,817 for 2017 and $6,818,684 for 2018, based on the 2016 rate base allocator of 18.3% in Tables 55 and 56 as discussed above.

# Exhibit 3, Tab 1, Schedule 4

# Annual Price Cap Adjustment Mechanism

**ANNUAL PRICE CAP ADJUSTMENT MECHANISM**

As part of the *RRFE*, the OEB initiated a review of utility performance, per the *Defining and Measuring Performance of Electricity Transmitters and Distributors* (EB-2010-0379)" proceeding. As part of this proceeding, the Board contracted Pacific Economics Group Research, LLC ("PEG") to prepare a report to the Board (the "PEG Report") entitled, *Empirical Research in Support of Incentive Rate Setting in Ontario: Report to the Ontario Energy Board*. The original PEG Report was issued on May 3, 2013. It established the parameters for use to determine the Price Cap Index for the 4th Generation IRM (now referred to as Price Cap IR), including: a productivity factor of 0.00%, the approach to determine the Industry Specific Inflation Factor (replacing the 3rd Generation IRM GDP-IPI inflation factor), and the initial stretch factor assignments.

*Stretch Factor*

The Stretch Factor assignments for 2020 IRM filers have not yet been updated by the Board. Alectra Utilities has used a Stretch Factor of 0.3% in this Application, in accordance with the most recent PEG Report, issued on August 23, 2018. The August 2018 Report placed Alectra Utilities in Group III for the purpose of calculating stretch factors for 2019.

*Inflation Factor*

The Industry Specific Inflation Factor for 2020 filers has not yet been updated by the Board. Alectra Utilities has used the Industry Specific Inflation Factor published for 2019 IRM filers, i.e., 1.5%, as a proxy for 2020.

Alectra Utilities will update the IRM Model with the 2020 stretch factor and inflation factor, in order to calculate the Price Cap Index once these factors are published by the Board.

The Price Cap Index, as determined in the IRM Model, filed as Attachments 12 to 16 is 1.2%, is identified in Table 57, below.

**Table 57 – Calculation of Price Cap Index**

| Factor | % |
|---|---|
| Inflation Factor | 1.50% |
| Less: Productivity Factor | 0.00% |
| Less: Stretch Factor | -0.30% |
| **Price Cap Index** | **1.20%** |

The Price Cap Index of 1.2% has been applied to Alectra Utilities' 2019 Service Charges and Distribution Volumetric Rates by rate clasS to determine the 2020 Service Charges and Distribution Volumetric Rates. The Alectra Utilities 2020 Proposed Tariff of Rates and Charges for the Horizon Utilities, Brampton, PowerStream, Enersource and Guelph Hydro RZs are filed as Attachment 17 to 21.

# Exhibit 3, Tab 1, Schedule 5

# Rate Design for Residential Customers – PowerStream RZ

**RATE DESIGN FOR RESIDENTIAL CUSTOMERS – POWERSTREAM RZ**

On April 2, 2015, the OEB released its Board Policy: *A New Distribution Rate Design for Residential Customers*, which stated that electricity distributors will transition to a fully fixed monthly distribution service charge for residential customers over a four-year period commencing in 2016 and ending in 2019.

The Board directed that *"Each distributor will determine its fully fixed charge and will make equal increases in the fixed charge over four years to get to the fully fixed charge. At the same time, the usage charge will be reduced in order to keep the distributor revenue-neutral."*

PowerStream incorporated the first year transition adjustment in its proposed rates for 2017, in a manner consistent with OEB policy. As per the Decision and Order for the PowerStream 2016 Rate Application (EB-2015-0003), the Board accepted PowerStream's proposal to transition to a fully fixed monthly distribution charge over four years starting in 2017 and ending in 2020.

Alectra Utilities incorporated the second year transition adjustment in its proposed rates for 2018, for the PowerStream RZ, in a manner consistent with OEB policy. As per the Decision and Order for the 2018 annual filing, the Board approved the proposed increase in the fixed distribution rate and corresponding decrease in the variable distribution rate for the residential class in 2018.

Alectra Utilities incorporated the third year transition adjustment in its proposed rates for 2019, for the PowerStream RZ, in a manner consistent with OEB policy. As per the Decision and Order for the 2019 annual filing, the Board approved the proposed increase in the fixed distribution rate and corresponding decrease in the variable distribution rate for the residential class in 2019.

Alectra Utilities has incorporated the fourth and final year transition adjustment for the PowerStream RZ in its proposed rates for 2020. The calculation of the proposed residential fixed and variable rates is identified in Tab 17. Rev2Cost-GDPIPI of the IRM Model filed as Attachment 14.

The Board instructed distributors that, for the purposes of implementing the new fixed rate design, a 10% test will be applied to customers who consume much less electricity than the typical residential customers.

This will allow any mitigation plans to be tailored to those customers who use the least power and whose bills will likely increase due to the shift in the fixed rates. If a customer at the 10$^{th}$

consumption percentile level of electricity has a bill impact of 10% or higher, the distributor must make a proposal for a rate mitigation plan.

Alectra Utilities confirms that the Residential monthly service charge increase of $3.38 is below the threshold of $4 per month identified in the Board's policy. Accordingly, rate mitigation is not necessary since a customer at the lowest decile of electricity consumption will not have a bill impact of 10% or higher.

Alectra Utilities has followed the Board's direction to assess the combined effect of the shift to fixed rates and other bill impacts associated with changes in the cost of distribution service for the PowerStream RZ, by evaluating the total bill impact for a residential customer at the $10^{th}$ consumption percentile. The following is a description of the method that Alectra Utilities used to derive the $10^{th}$ consumption percentile for the PowerStream RZ.

1. Alectra Utilities ranked the annual kWh usage of active residential customers who consumed electricity at the location for a minimum of twelve months from the lowest to the highest number of kWhs for the PowerStream RZ.
2. Alectra Utilities looked at the consumption level of the customer whose rank was $1/10^{th}$ of the total number of customers ranked for the PowerStream RZ.
3. Alectra Utilities calculated the $10^{th}$ percentile customer's average monthly usage by dividing the annual consumption by 12 months for the PowerStream RZ.
4. Alectra Utilities determined the number of monthly kWhs at the $10^{th}$ consumption percentile to be 302 kWh for the PowerStream RZ.

In Table 58 below, Alectra Utilities has provided the bill impact for a Residential customer who consumes 302 kWh monthly. The monthly service charge increased by $3.38 and the total bill impact for a customer at the 10th consumption percentile of electricity consumption is 4.48%.

## Table 58 – 10th Consumption Percentile Residential Customer Bill Impact (302 kWh) – PowerStream RZ

| | |
|---|---|
| **Customer Class:** | **RESIDENTIAL SERVICE CLASSIFICATION** |
| **RPP / Non-RPP:** | **RPP** |
| **Consumption** | **302** kWh |
| **Current Loss Factor** | **1.0369** |

| | Current OEB-Approved | | | Proposed | | | Impact | |
|---|---|---|---|---|---|---|---|---|
| | Rate ($) | Volume | Charge ($) | Rate ($) | Volume | Charge ($) | $ Change | % Change |
| Monthly Service Charge | **$ 24.91** | 1 | $ 24.91 | **$ 28.29** | 1 | $ 28.29 | $ 3.38 | 13.57% |
| Distribution Volumetric Rate | **$ 0.0045** | 302 | $ 1.36 | **$ -** | 302 | $ - | $ (1.36) | -100.00% |
| Fixed Rate Riders | **$ 0.31** | 1 | $ 0.31 | **$ 0.29** | 1 | $ 0.29 | $ (0.02) | -6.45% |
| Volumetric Rate Riders | **$ 0.0004** | 302 | $ 0.12 | **$ 0.0006** | 302 | $ 0.18 | $ 0.06 | 50.00% |
| **Sub-Total A (excluding pass through)** | | | $ 26.70 | **$ -** | 0 | $ 28.76 | **$ 2.06** | **7.73%** |
| Line Losses on Cost of Power | **$ 0.0824** | 11 | $ 0.92 | **$ 0.0824** | 11 | $ 0.92 | $ - | 0.00% |
| Total Deferral/Variance Account Rate Riders | **-$ 0.0021** | 302 | $ (0.63) | **-$ 0.0008** | 302 | $ (0.24) | $ 0.39 | -61.90% |
| Low Voltage Service Charge | **$ 0.0005** | 302 | $ 0.15 | **$ 0.0005** | 302 | $ 0.15 | $ - | 0.00% |
| Smart Meter Entity Charge (if applicable) | **$ 0.57** | 1 | $ 0.57 | **$ 0.57** | 1 | $ 0.57 | $ - | 0.00% |
| **Sub-Total B - Distribution (includes Sub-Total A)** | **0** | | **$ 27.70** | **0** | 0 | **$ 30.16** | **$ 2.45** | **8.86%** |
| RTSR - Network | **$ 0.0073** | 313 | $ 2.28 | **$ 0.0076** | 313 | $ 2.38 | $ 0.09 | 4.11% |
| RTSR - Connection and/or Line and Transformation Connection | **$ 0.0040** | 313 | $ 1.25 | **$ 0.0041** | 313 | $ 1.28 | $ 0.03 | 2.50% |
| **Sub-Total C - Delivery (including Sub-Total B)** | **0** | | **$ 31.24** | **0** | **0** | **$ 33.82** | **$ 2.58** | **8.26%** |
| Wholesale Market Service Charge (WMSC) | **$ 0.0034** | 313 | $ 1.06 | **$ 0.0034** | 313 | $ 1.06 | $ - | 0.00% |
| Rural and Remote Rate Protection (RRRP) | **$ 0.0005** | 313 | $ 0.16 | **$ 0.0005** | 313 | $ 0.16 | $ - | 0.00% |
| Standard Supply Service Charge | **$ 0.25** | 1 | $ 0.25 | **$ 0.25** | 1 | $ 0.25 | $ - | 0.00% |
| TOU - Off Peak | **$ 0.0650** | 196 | $ 12.75 | **$ 0.0650** | 196 | $ 12.75 | $ - | 0.00% |
| TOU - Mid Peak | **$ 0.0940** | 51 | $ 4.82 | **$ 0.0940** | 51 | $ 4.82 | $ - | 0.00% |
| TOU - On Peak | **$ 0.1340** | 54 | $ 7.28 | **$ 0.1340** | 54 | $ 7.28 | $ - | 0.00% |
| | | | | | | | | |
| **Total Bill on TOU (before Taxes)** | | | **$ 57.55** | | | **$ 60.13** | **$ 2.58** | **4.48%** |
| HST | 13% | | $ 7.48 | 13% | | $ 7.82 | $ 0.34 | 4.48% |
| 8% Provincial Rebate | -8% | | $ (4.60) | -8% | | $ (4.81) | $ (0.21) | 4.48% |
| **Total Bill on TOU** | | | **$ 60.43** | | | **$ 63.14** | **$ 2.71** | **4.48%** |
| | | | | | | | | |

# Exhibit 3, Tab 1, Schedule 6

# Electricity Distribution Retail Transmission Service Rates

**ELECTRICITY DISTRIBUTION RETAIL TRANSMISSION SERVICE RATES**

The Board's *Guideline for Electricity Distribution Retail Transmission Service Rates* ("RTSR Guideline") (G-2008-0001) was issued June 28, 2012. On December 20 2018, the OEB issued its Decision and Order in respect of the 2019 Uniform Transmission Rates ("UTRs") (EB-2018-0326). On December 21, 2016, the OEB issued its Decision and Order in respect of Hydro One Networks Inc. ("HONI") application for electricity distribution rates and other charges beginning January 1, 2017, which contain HONI's sub transmission rates ("STRs) at page 10 (EB-2016-0081). The most recent UTRs and STRs are identified in Table 59 below.

**Table 59 – Current Board-Approved UTRs and STRs**

| UTRs | $ |
|---|---|
| Network Service Rate | $3.71 |
| Line Connection Service Rate | $0.94 |
| Transformation Connection Service Rate | $2.25 |

| STRs | $ |
|---|---|
| Network Service Rate | $3.1942 |
| Line Connection Service Rate | $0.7710 |
| Transformation Connection Service Rate | $1.7493 |

Alectra Utilities has updated Tabs 11-15 of the IRM Model, filed as Attachments 12 to 16, to incorporate: i) the most recent UTRs and STRs approved by the Board; and ii) an update to Alectra Utilities demand in the Horizon Utilities, Brampton, PowerStream, Enersource and Guelph Hydro RZs from 2017 to 2018 actual values. The RTSRs are calculated in Tab 16 of the IRM Model.

Alectra Utilities will update the RTSRs for all rate zones, should the actual UTRs and STRs be approved prior to the OEB issuing the final rate order for this application.

# Exhibit 3, Tab 1, Schedule 7

## Review and Disposition of Group 1 Deferral

## and

## Variance Account Balances

**REVIEW AND DISPOSITION OF GROUP 1 DEFERRAL AND VARIANCE ACCOUNT BALANCES**

As discussed in the *Report of the Board on the Electricity Distributors' Deferral and Variance Account Review Initiative (*EB-2008-0046), (the "EDDVAR Report"), issued July 31, 2009, under the Price Cap IR or the Annual IR Index, the distributor's Group 1 account balances will be reviewed and disposed if the pre-set disposition threshold of $0.001 per kWh (debit or credit) is met. Consistent with a Letter from the Board to Licensed Electricity Distributors re: *Process for 2015 Incentive Regulation Mechanism ("IRM") Distribution Rate Applications*, dated July 25, 2014, distributors may also elect to dispose of Group 1 account balances below the threshold.

On February 21, 2019, the OEB issued a Letter to all rate-regulated electricity distributors re: *Accounting Guidance related to Accounts 1588 RSVA Power, and 1589 RSVA Global Adjustment.* The OEB provided an update to the Accounting Procedures Handbook ("APH") standardizing requirements for regulatory accounting and Regulated Price Plan ("RPP") settlements. Distributors are expected to implement the new guidance no later than August 31, 2019, retroactive to January 2019. Further, on May 15, 2019, the OEB issued a Letter re: *Accounting Guidance for IESO Charge Type 2148.* The letter provides accounting guidance for the new IESO charge type 2148 Class B Global Adjustment Prior Period Correction Settlement Amount, which captures corrections to prior period input data for embedded generation, energy storage or Class A load quanities for impacted market participants. Alectra Utilities is reviewing and assessing the impact of the new accounting guidance issued February 21 and May 15, and will implement the guidance by August 31.

Group 1 accounts consist of the following Uniform System of Accounts ("USoA"):

- 1550 - Low Voltage Account;
- 1551 - SME Charge Account;
- 1580 - RSVA Wholesale Market Service Charge Account;
- 1584 - RSVA Retail Transmission Network Charge Account;
- 1586 - RSVA Retail Transmission Connection Charge Account;
- 1588 - RSVA Power Account;

- 1589 - RSVA Global Adjustment Account;
- 1590 - Recovery of Regulatory Asset Balances Account (if applicable); and
- 1595 - Disposition and Recovery/Refund of Regulatory Balances Account.

Alectra Utilities provides the relief sought for its Group 1 deferral and variance account balances by rate zone, below.

**Horizon Utilities RZ**

The Group 1 balances as of December 31, 2018, in the amount of ($5,922,706) have been adjusted for the following items to determine the amount for disposition of $3,828,158 as identified in Table 60, below:

- Only residual balances in Account 1595 for which rate riders have expired are included;
- RPP settlement true-up claims for a given fiscal year that have not been included in the audited financial statements have been 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*". Consequently, the account balances on Tab 3. Continuity Schedule differ from the annual RRR filing;
- 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 projected carrying charges to December 31, 2019).

**Table 60 – Group 1 Balances for Disposition – Horizon Utilities RZ**

| Description | Amount |
|---|---|
| **Group 1 Account Balances as of December 31, 2018** | **($5,922,706)** |
| Subtract 2018 Annual Filing Disposition (EB-2018-0016) - Refund to Customers | ($8,423,900) |
| Add RPP Settlement True-up Claims Adjustment | $6,927 |
| Add Projected Carrying Charges | $59,587 |
| Deduct 1595 Residual Balances to be disposed in a future rate proceeding | ($1,260,449) |
| **Adjusted Group 1 Account Balances for Disposition - Recovery from Customers** | **$3,828,158** |

Alectra Utilities has computed the disposition threshold for the Horizon Utilities RZ, based on the adjusted Group 1 balances to be $0.0007/kWh, which is below the OEB's pre-set disposition threshold, as identified in Table 61, below. Alectra Utilities does not request disposition of its Group 1 account balances in this Annual Filing for the Horizon Utilities RZ.

**Table 61 - Calculation of Disposition Threshold – Horizon Utilities RZ**

| Description | Account | Amount |
|---|---|---|
| Low Voltage | 1550 | $926,541 |
| Smart Meter Entity Charge | 1551 | ($209,727) |
| RSVA - Wholesale Market Service Charge excluding CBR | 1580 | ($5,275,607) |
| RSVA - Wholesale Market Service Charge - Capacity Based Recovery ("CBR") Class B | 1580 | ($148,933) |
| RSVA - Retail Transmission Network Charge | 1584 | $828,214 |
| RSVA - Retail Transmission Connection Charge | 1586 | $2,699,051 |
| RSVA - Power | 1588 | $1,465,374 |
| RSVA - Global Adjustment | 1589 | ($4,338,832) |
| Disposition and Recovery/Refund of Regulatory Balances | 1595 | ($1,868,787) |
| **Group 1 Account Balances as of December 31, 2018** | | **($5,922,706)** |
| Subtract 2018 Annual Filing Disposition (EB-2018-0016) - Refund to Customers | | ($8,423,900) |
| Add RPP Settlement True-up Claims Adjustment | | $6,927 |
| Add Projected Carrying Charges | | $59,587 |
| Deduct 1595 Residual Balances to be disposed in a future rate proceeding | | ($1,260,449) |
| **Adjusted Group 1 Account Balances for Disposition - Recovery from Customers** | | **$3,828,158** |
| 2018 kWhs | | 5,411,304,515 |
| **Threshold Test $/kWh** | | **$0.0007** |

**<u>Brampton RZ</u>**

The Group 1 balances as of December 31, 2018, in the amount of ($6,008,562) have been adjusted for the following items to determine the amount for disposition of ($2,229,940) as identified in Table 62, below:

- Only residual balances in Account 1595 for which rate riders have expired are included;
- RPP settlement true-up claims for a given fiscal year that have not been included in the audited financial statements have been 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*". Consequently, the account balances on Tab 3. Continuity Schedule differ from the annual RRR filing;
- 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 projected carrying charges to December 31, 2019).

**Table 62 – Group 1 Balances for Disposition – Brampton RZ**

| Description | Amount |
|---|---|
| **Group 1 Account Balances as of December 31, 2018** | **($6,008,562)** |
| Subtract 2018 Annual Filing Disposition (EB-2018-0016) - Refund to Customers | ($2,883,103) |
| RPP Settlement True-up Claims Adjustment | ($871,397) |
| Add Projected Carrying Charges | ($83,791) |
| Deduct 1595 Residual Balances to be disposed in a future rate proceeding | ($1,850,706) |
| **Adjusted Group 1 Account Balances for Disposition - Refund to Customers** | **($2,229,940)** |

Alectra Utilities has computed the disposition threshold for the Brampton RZ, based on the adjusted Group 1 balances to be ($0.0005/kWh), which is below the OEB's pre-set disposition threshold, as identified in Table 63, below.  Alectra Utilities does not request disposition of its Group 1 account balances in this Annual Filing for the Brampton RZ.

**Table 63 - Calculation of Disposition Threshold – Brampton RZ**

| Description | Account | Amount |
|---|---|---|
| Low Voltage | 1550 | $407,821 |
| Smart Meter Entity Charge | 1551 | ($197,061) |
| RSVA - Wholesale Market Service Charge excluding CBR | 1580 | ($4,481,882) |
| RSVA - Wholesale Market Service Charge - Capacity Based Recovery ("CBR") Class B | 1580 | ($229,291) |
| RSVA - Retail Transmission Network Charge | 1584 | $396,694 |
| RSVA - Retail Transmission Connection Charge | 1586 | $1,128,568 |
| RSVA - Power | 1588 | ($1,050,947) |
| RSVA - Global Adjustment | 1589 | ($251,292) |
| Disposition and Recovery/Refund of Regulatory Balances | 1595 | ($1,731,172) |
| **Group 1 Account Balances as of December 31, 2018** | | **($6,008,562)** |
| Subtract 2018 Annual Filing Disposition (EB-2018-0016) - Refund to Customers | | ($2,883,103) |
| RPP Settlement True-up Claims Adjustment | | ($871,397) |
| Add Projected Carrying Charges | | ($83,791) |
| Deduct 1595 Residual Balances to be disposed in a future rate proceeding | | ($1,850,706) |
| **Adjusted Group 1 Account Balances for Disposition - Refund to Customers** | | **($2,229,940)** |
| 2018 kWhs | | 4,131,633,817 |
| **Threshold Test $/kWh** | | **($0.0005)** |

**<u>PowerStream RZ</u>**

The Group 1 balances as of December 31, 2018, in the amount of ($31,038,670) have been adjusted for the following items to determine the amount for disposition of ($14,438,240) as identified in Table 64, below:

- Only residual balances in Account 1595 for which rate riders have expired are included;
- RPP settlement true-up claims for a given fiscal year that have not been included in the audited financial statements have been 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*". Consequently, the account balances on Tab 3. Continuity Schedule differ from the annual RRR filing;
- 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 projected carrying charges to December 31, 2019).

**Table 64 – Group 1 Balances for Disposition – PowerStream RZ**

| **Group 1 Account Balances as of December 31, 2018** | **($31,038,670)** |
|---|---|
| Subtract 2018 Annual Filing Disposition (EB-2018-0016) - Refund to Customers | ($10,593,164) |
| RPP Settlement True-up Claims Adjustment | $35,206 |
| Add Projected Carrying Charges | ($436,362) |
| Deduct 1595 Residual Balances to be disposed in a future rate proceeding | ($6,408,423) |
| **Adjusted Group 1 Account Balances for Disposition - Refund to Customers** | **($14,438,240)** |

Alectra Utilities has computed the disposition threshold for the PowerStream RZ, based on the adjusted Group 1 balances to be ($0.0017/kWh), as identified in Table 65, below. Alectra Utilities requests disposition of its Group 1 account balances in this Annual Filing for the PowerStream RZ.

**Table 65 - Calculation of Disposition Threshold – PowerStream RZ**

| Description | Account | Amount |
|---|---|---|
| Low Voltage | 1550 | $2,080,828 |
| Smart Meter Entity Charge | 1551 | ($699,924) |
| RSVA - Wholesale Market Service Charge excluding CBR | 1580 | ($9,904,751) |
| RSVA - Wholesale Market Service Charge - Capacity Based Recovery ("CBR") Class B | 1580 | ($320,837) |
| RSVA - Retail Transmission Network Charge | 1584 | ($8,758,902) |
| RSVA - Retail Transmission Connection Charge | 1586 | ($224,187) |
| RSVA - Power | 1588 | ($10,021,843) |
| RSVA - Global Adjustment | 1589 | $3,094,985 |
| Disposition and Recovery/Refund of Regulatory Balances | 1595 | ($6,284,040) |
| **Group 1 Account Balances as of December 31, 2018** | | **($31,038,670)** |
| Subtract 2018 Annual Filing Disposition (EB-2018-0016) - Refund to Customers | | ($10,593,164) |
| RPP Settlement True-up Claims Adjustment | | $35,206 |
| Add Projected Carrying Charges | | ($436,362) |
| Deduct 1595 Residual Balances to be disposed in a future rate proceeding | | ($6,408,423) |
| **Adjusted Group 1 Account Balances for Disposition - Refund to Customers** | | **($14,438,240)** |
| 2018 kWhs | | 8,629,509,610 |
| **Threshold Test $/kWh** | | **($0.0017)** |

Alectra Utilities has completed and filed Tabs 3 to 8 of the modified IRM Model as Attachment 14 for the PowerStream RZ. Alectra Utilities has reconciled the Group 1 balances filed in the 2018 RRR, section 2.1.7 for the PowerStream RZ, as identified in Table 66, below. Alectra Utilities confirms that the last Board approved balance of ($10,593,164) for the PowerStream RZ has been transferred to Account 1595. Further, Alectra Utilities has confirmed the accuracy of the billing determinants to the 2018 RRR, section 2.1.5.4. Alectra Utilities relied upon the Board’s prescribed interest rates to calculate carrying charges on the deferral and variance account balances. The prescribed interest rates of 2.45% for 2019 Q1 and 2.18% for 2019 Q2-Q4 were used to calculate forecasted interest for 2019. No adjustments have been made to any deferral and variance account balances previously approved by the Board on a final basis.

## Table 66 – Deferral and Variance Account Reconciliation – PowerStream RZ

| Account Description | Account | Principal Amounts as of Dec 31, 2018 | Carrying Charges to Dec 31, 2018 | Principal Disposition during 2019 - instructed by Board EB-2018-0016 | Interest Disposition during 2019 - instructed by Board EB-2018-0016 | Projected Carrying Charges to Dec 31, 2019 | Total Disposition before RPP True-Up Adjustment | RPP Settlement True-up Claims Adjustment | Projected Carrying Charges to December 31, 2019 | 1595 Balances Not Claimed in 2019 | Total Disposition |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Group 1 Accounts:** | | | | | | | | | | | |
| Low Voltage | 1550 | 2,032,164 | 48,663 | (1,506,288) | (16,401) | 11,819 | 569,958 | | | | 569,958 |
| Smart Meter Entity Charge | 1551 | (687,484) | (12,440) | 389,459 | 7,297 | (6,698) | (309,866) | | | | (309,866) |
| RSVA - Wholesale Market Service Charge excluding CBR | 1580 | (9,675,528) | (229,223) | 7,987,408 | 68,232 | (37,941) | (1,887,052) | | | | (1,887,052) |
| RSVA - Wholesale Market Service Charge - CBR B | 1580 | (318,953) | (1,884) | 84,171 | 12,899 | (5,277) | (229,043) | | | | (229,043) |
| RSVA - Retail Transmission Network Charge | 1584 | (8,548,331) | (210,570) | 6,668,761 | 143,108 | (42,243) | (1,989,276) | | | | (1,989,276) |
| RSVA - Retail Transmission Connection Charge | 1586 | (210,581) | (13,606) | 1,010,067 | 42,608 | 17,968 | 846,457 | | | | 846,457 |
| RSVA - Power | 1588 | (9,888,801) | (133,042) | 223,398 | 44,280 | (217,230) | (9,971,394) | 6,867,808 | 154,354 | | (2,949,233) |
| **Sub-total not including RSVA Power Global Adjustment** | | (27,297,514) | (552,102) | 14,856,977 | 302,023 | (279,601) | (12,970,217) | 6,867,808 | 154,354 | | (5,948,055) |
| RSVA - Power Global Adjustment | 1589 | 2,970,754 | 124,231 | (4,446,571) | (119,265) | (33,169) | (1,504,020) | (6,832,602) | (153,563) | | (8,490,185) |
| **Total including RSVA Power Global Adjustment** | | (24,326,760) | (427,870) | 10,410,406 | 182,758 | (312,770) | (14,474,236) | 35,206 | 791 | | (14,438,240) |
| Disposition and Recovery/Refund of Regulatory Balances (2014) | 1595 | 35,118 | 1,645 | | | 789 | 37,553 | | | 37,553 | - |
| Disposition and Recovery/Refund of Regulatory Balances (2016) | 1595 | 2,284 | (5,476) | | | 51 | (3,141) | | | (3,141) | - |
| Disposition and Recovery/Refund of Regulatory Balances (2018) | 1595 | (5,571,701) | (745,910) | | | (125,224) | (6,442,835) | | | (6,442,835) | - |
| **Total 1595** | | (5,534,298) | (749,742) | - | - | (124,383) | (6,408,423) | - | - | (6,408,423) | - |
| **Total Group 1** | | **(29,861,058)** | **(1,177,612)** | **10,410,406** | **182,758** | **(437,153)** | **(20,882,660)** | **35,206** | **791** | **(6,408,423)** | **(14,438,240)** |
| **Total Amount for Disposition** | | **(29,861,058)** | **(1,177,612)** | **10,410,406** | **182,758** | **(437,153)** | **(20,882,660)** | **35,206** | **791** | **(6,408,423)** | **(14,438,240)** |

Alectra Utilities is seeking a one-year disposition period for the Group 1 balances for the PowerStream RZ. This approach is consistent with the EDDVAR Report which states on page 6 that "*the default disposition period used to clear the account balances through a rate rider should be one year"*.

**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. 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 ("CBR") Disposition**

Alectra Utilities has also established separate rate riders to dispose of the global adjustment ("GA") account balances for the PowerStream RZ. The GA rate riders are applicable for non-RPP Class B customers only. Alectra Utilities' Class A customers are invoiced actual GA, therefore, none of the variance in the GA account balance should be attributed to these customers. The OEB's Chapter 3 Filing Requirements state: "*If the allocated Account 1580 sub-account CBR Class B amount does not produce a rate rider in one or more rate class (except for the Standby rate class), a distributor is to transfer the entire OEB-approved CBR Class B amount into Account 1580 WMS control account to be disposed through the general purpose Group 1 DVA rate riders.*" Alectra Utilities submits that the balance in Sub-account 1580 – CBR Class B was not material enough to result in a rate rider and therefore the balance was transferred to Account 1580 WMS control account to be disposed through the general purpose Group 1 DVA rate riders.

There were 31 Alectra Utilities customers in the PowerStream RZ that newly qualified as Class A customers effective July 1, 2018, under the IESO's expansion of the Industrial Conservation Initiative ("ICI"). These customers paid GA as Class B customers up to and including June 30, 2018; and paid GA as Class A customers from July 1, 2018 to December 31, 2018. As such, these customers should be allocated only the portion of the GA account balance which accrued prior to their classification as Class A customers (i.e. from January 1, 2018 to June 30, 2018).

There were 12 Alectra Utilities customers in the PowerStream RZ customer who ceased to qualify as a Class A customer effective July 1, 2018 under the IESO's expansion of the Industrial Conservation Initiative ("ICI"). These customers paid GA as Class A customers up to and including June 30, 2018; and paid GA as Class B customers from July 1, 2018 to December 31, 2018.

As such, these customers should be allocated only the portion of the GA account balance which accrued after their reclassification to Class B customers (i.e. from July 1, 2018 to December 31, 2018).

These GA amounts will be settled through twelve equal adjustments to bills as directed in the Chapter 3 Filing Requirements. These customers will not be charged the GA rate riders.

Table 67 below identifies the GA balances disposed of through rate riders and specific bill adjustments.

Alectra Utilities requests disposition of its total GA balance of ($8,490,185), of which ($8,191,727) will be disposed of via rate rider; and ($78,843) and ($219,615) will be disposed of via specific bill adjustments to the 31 new Class A customers and 12 new Class B customers respectively, as discussed above. Tab "6.1a GA Allocation" in the IRM Model identifies the detailed calculation of the bill adjustments.

**Table 67 –Disposition of GA Balances – PowerStream RZ**

| Description | Amount |
|---|---|
| Global Adjustment - Non-RPP Class B Customers Jan 1/2018- Dec 31/2018 | ($8,191,727) |
| Global Adjustment - New Class A Customers July 1/2018 | ($219,615) |
| Global Adjustment - New Class B Customers July 1/2018 | ($78,843) |
| **Class B Non-RPP Customers only - GA Rate Rider/Bill Adjustment** | **($8,490,185)** |

A summary of the rate riders applicable to each group of customers is identified in Table 68 below.

**Table 68 – Rate Riders by Customer Group – PowerStream RZ**

| Customers | DVA Rate Rider 1 [1] | DVA Rate Rider 2 [2] | CBR B Rate Rider | GA Rate Rider | GA Bill Adjustment |
|---|---|---|---|---|---|
| WMPs | x | | | | |
| Class A (Jan 1, 2018 - Dec 31, 2018) | x | x | | | |
| Class B non-RPP (Jan 1, 2018 - Jun 30, 2018)/Class A (Jul 1, 2018 - Dec 31, 2018) Customers | x | x | | | x |
| Class A non-RPP (Jan 1, 2018 - Jun 30, 2018)/Class B (Jul 1, 2018 - Dec 31, 2018) Customers | x | x | | | x |
| Class B non-RPP (Jan 1, 2018 - Dec 31, 2018) Customers | x | x | N/A | x | |
| Class B RPP Customers | x | x | N/A | | |

1. DVA Rate Rider 1 = disposition of low voltage, SME, Network, Connection, IRM balances
2. DVA Rate Rider 2 = disposition of Power and Wholesale Market Service Charges

WMPs are charged DVA Rate Rider 1 only, which includes account balances for low voltage charges, retail transmission network charges, retail transmission connection charges.

Class A customers (who were Class A from January 1 – December 31, 2018) are charged the sum of DVA Rate Rider 1 and DVA Rate Rider 2, the latter of which includes account balances for power and wholesale market service charges excluding CBR.

Class B, non-RPP customers (who were Class A customers for only a part of 2018) are charged the sum of DVA Rate Rider 1 and DVA Rate Rider 2; and a bill adjustment for their portion of the GA account balances.

Class A, non-RPP customers (who were Class B customers for only part of 2018) are charged the sum of DVA Rate Rider 1 and DVA Rate Rider 2; and a bill adjustment for their portion of the GA account balances.

Class B, non-RPP customers (who were Class B from January 1 – December 31, 2018) are charged the sum of DVA Rate Riders 1 and 2; and the GA Rate Rider.

Class B RPP customers are charged the sum of DVA Rate Riders 1 and 2.

The Group 1 DVAs disposition by customer group is identified in Table 69, below.

**Table 69 – Group 1 DVAs Disposition by Customer Group – PowerStream RZ**

| Description | Account | Amount |
|---|---|---|
| Low Voltage | 1550 | $569,958 |
| Smart Meter Entity Charge (Residential and GS<50kW Classes Only) | 1551 | ($309,866) |
| Retail Transmission Network Charge | 1584 | ($1,989,276) |
| Retail Transmission Connection Charge | 1586 | $846,457 |
| Disposition and Recovery/Refund of Regulatory Balances | 1595 | $0 |
| **All Customers - DVA Rate Rider 1** | | **($882,727)** |
| | | |
| Power | 1588 | ($2,949,233) |
| Wholesale Market Service Charge | 1580 | ($2,116,095) |
| **All Customers ex WMPs - DVA Rate Rider 2** | | **($5,065,327)** |
| | | |
| Wholesale Market Service Charge - CBR Class B | 1580 | $0 |
| Wholesale Market Service Charge - New Class A/B Customers July 1/2018 | | $0 |
| **All Class B Customers ex WMPs - CBR B Bill Adjustment** | **1580** | **$0** |
| | | |
| Global Adjustment - Non-RPP Class B Customers Jan 1/2018 -Dec 31/2018 | 1589 | ($8,180,853) |
| Global Adjustment - New Class A/B Customers July 1/2018 | 1589 | ($309,332) |
| **Class B Non-RPP Customers only - GA Rate Rider/Bill Adjustment** | | **($8,490,185)** |
| | | |
| **Total (Repayment to)/Recovery from Customers** | | **($14,438,240)** |
| Disposition via Rate Rider | | ($14,128,908) |
| Disposition via Customer Specific Bill Adjustments - GA for Class A customers only a portion of 2018 | | ($309,332) |
| Disposition via Customer Specific Bill Adjustments - CBR for Class A/B customers only a portion of 2018 | | $0 |

All balances claimed are allocated to the rate classes based on the default cost allocation methodology as identified in the EDDVAR report. The 2018 actuals reported in Alectra Utilities 2018 RRRs have been used to calculate the rate riders as per the Chapter 3 Filing Requirements issued by the OEB on July 12, 2018.

The billing determinants, billing adjustments and calculation of the rate riders are provided in Tabs 4 through 8 in the IRM Model filed as Attachment 14. Table 70 below summarizes the deferral and variance rate riders by class.

**Table 70 – Deferral and Variance Account Riders – PowerStream RZ**

| Customer Class | Deferral/Variance | | Deferral/Variance | | Global Adjustment | | CBR B | |
|---|---|---|---|---|---|---|---|---|
| | $/kWh | $/kW | $/kWh | $/kW | $/kWh | $/kW | $/kWh | $/kW |
| Residential | (0.0008) | | | | (0.0026) | | 0.0000 | |
| General Service Less Than 50 kW | (0.0007) | | | | (0.0026) | | 0.0000 | |
| General Service 50 To 4,999 kW | | (0.0255) | | (0.2261) | (0.0026) | | | 0.0000 |
| Large Use | | (0.3391) | | | 0.0000 | | | 0.0000 |
| Unmetered Scattered Load | (0.0007) | | | | (0.0026) | | 0.0000 | |
| Sentinel Lighting | | (0.2358) | | | (0.0026) | | | 0.0000 |
| Street Lighting | | (0.2388) | | | (0.0026) | | | 0.0000 |

Alectra Utilities requests disposition of the PowerStream RZ adjusted Group 1 balances of ($14,438,240), identified in Table 64, through the rate riders identified in Table 70, above.

**GA Analysis Workform**

The GA Analysis Workform ("GA Workform") for the PowerStream RZ is filed as Attachment 22. The GA Workform compares the principal activity in the general ledger for Account 1589, Global Adjustment to the expected principal balance based on monthly GA volumes, revenue and costs. The GA workform provides a tool to assess if the principal activity in Account 1589 for a specific year is reasonable.

The principal activity in Account 1589 recorded in 2018 was ($1,475,817) as identified in Table 71 below. The principal activity balance, after known adjustments of ($6,832,602) was ($8,308,419). This is compared to the expected principal balance in Account 1589 of ($6,400,661) calculated in Attachment 22, which results in an unreconciled difference of ($1,907,758). This represents 0.59% of Alectra Utilities 2018 IESO purchases in the PowerStream RZ, which is within the OEB's threshold (+/- 1% of IESO purchases).

**Table 71 – GA Workform Summary**

| Description | Amount |
|---|---|
| **Principal Activity in RSVA(GA)** | ($1,475,817) |
| Add Known Adjustments | ($6,832,602) |
| **Adjusted Principal Activity in RSVA(GA)** | ($8,308,419) |
| **Expected Principal Activity in RSVA(GA)** | ($6,400,661) |
| **Variance $** | ($1,907,758) |
| Total 2018 IESO Purchases | $321,232,997 |
| **Absolute Variance as a % of IESO Purchases** | 0.59% |

**1595 Analysis Workform**

The 1595 Workform compares the principal and interest amounts previously approved for disposition to the residual balances remaining after the amounts have been recovered or refunded to customers through rate riders. As discussed in the Chapter 3 Filing Requirements, *"the balances in Account 1595 will first be assessed in two groups of accounts; one being the amounts attributable to GA, and the other being the remainder of Group 1 and Group 2 Accounts (if applicable). A residual balance in either of the two groups of accounts exceeding +/- 10% of the original amounts previously approved for disposition would be considered material."* The 1595 workform provides a tool to assess if the residual balance in Account 1595 for a specific year is reasonable. Distributors can only seek disposition of the audited account balances in Account 1595, a year after the rate rider's sunset date has expired. In this Application, Alectra Utilities is not requesting disposition of its 1595 sub-account balances for the PowerStream RZ as it does not meet the requirements for disposition of residual balances.

**Enersource RZ**

The Group 1 balances as of December 31, 2018, in the amount of ($5,577,964) have been adjusted for the following items to determine the amount for disposition of ($7,615,246) as identified in Table 72, below:

- Only residual balances in Account 1595 for which rate riders have expired are included;
- RPP settlement true-up claims for a given fiscal year that have not been included in the audited financial statements have been 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*". Consequently, the account balances on Tab 3. Continuity Schedule differ from the annual RRR filing;
- 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 projected carrying charges to December 31, 2019).

**Table 72 – Group 1 Balances for Disposition – Enersource RZ**

| Description | Amount |
|---|---|
| **Group 1 Account Balances as of December 31, 2018** | **($5,577,964)** |
| Subtract 2018 Annual Filing Disposition (EB-2018-0016) - Recovery from Customers | $2,926,490 |
| RPP Settlement True-up Claims Adjustment | ($908,924) |
| Add Projected Carrying Charges | ($208,554) |
| Deduct 1595 Residual Balances to be disposed in a future rate proceeding | $2,006,685 |
| **Adjusted Group 1 Account Balances for Disposition - Refund to Customers** | **($7,615,246)** |

Alectra Utilities has computed the disposition threshold for the Enersource RZ, based on the adjusted Group 1 balances to be ($0.0010/kWh), as identified in Table 73, below. Alectra Utilities requests disposition of its Group 1 account balances in this Annual Filing for the Enersource RZ.

**Table 73 - Calculation of Disposition Threshold – Enersource RZ**

| Description | Account | Amount |
|---|---|---|
| Low Voltage | 1550 | $4,262,004 |
| Smart Meter Entity Charge | 1551 | ($172,522) |
| RSVA - Wholesale Market Service Charge excluding CBR | 1580 | ($7,146,198) |
| RSVA - Wholesale Market Service Charge - Capacity Based Recovery ("CBR") Class B | 1580 | ($478,530) |
| RSVA - Retail Transmission Network Charge | 1584 | $2,181,002 |
| RSVA - Retail Transmission Connection Charge | 1586 | $4,652,855 |
| RSVA - Power | 1588 | ($3,869,800) |
| RSVA - Global Adjustment | 1589 | ($2,976,366) |
| Disposition and Recovery/Refund of Regulatory Balances | 1595 | ($2,030,409) |
| **Group 1 Account Balances as of December 31, 2018** | | **($5,577,964)** |
| Subtract 2018 Annual Filing Disposition (EB-2018-0016) - Recovery from Customers | | $2,926,490 |
| RPP Settlement True-up Claims Adjustment | | ($908,924) |
| Add Projected Carrying Charges | | ($208,554) |
| Deduct 1595 Residual Balances to be disposed in a future rate proceeding | | $2,006,685 |
| **Adjusted Group 1 Account Balances for Disposition - Refund to Customers** | | **($7,615,246)** |
| 2018 kWhs | | 7,267,115,621 |
| **Threshold Test $/kWh** | | **($0.0010)** |

Alectra Utilities has completed and filed Tabs 3 to 8 of the modified IRM Model as Attachment 15 for the Enersource RZ. Alectra Utilities has reconciled the Group 1 balances filed in the 2018 RRR, section 2.1.7 for the Enersource RZ, as identified in Table 74, below. Alectra Utilities confirms that the last Board approved balance of $2,926,490 for the Enersource RZ has been transferred to Account 1595. Further, Alectra Utilities has confirmed the accuracy of the billing determinants to the 2018 RRR, section 2.1.5.4. Alectra Utilities relied upon the Board's prescribed interest rates to calculate carrying charges on the deferral and variance account balances. The prescribed interest rate of 2.45% for 2019 Q1 and 2.18% for 2019 Q2-Q4 were used to calculate forecasted interest for 2019. No adjustments have been made to any deferral and variance account balances previously approved by the Board on a final basis.

## Table 74 – Deferral and Variance Account Reconciliation – Enersource RZ

| Account Description | Account | Principal Amounts as of Dec 31, 2018 | Carrying Charges to Dec 31, 2018 | Principal Disposition during 2019 - instructed by Board EB-2018-0016 | Interest Disposition during 2019 - instructed by Board EB-2018-0016 | Projected Carrying Charges to Dec 31, 2019 | Total Disposition before RPP True-Up Adjustment | RPP Settlement True-up Claims Adjustment | Projected Carrying Charges to December 31, 2019 | 1595 Balances Not Claimed in 2019 | Total Disposition |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Group 1 Accounts:** | | | | | | | | | | | |
| Low Voltage | 1550 | 4,182,767 | 79,237 | (2,379,788) | (51,921) | 40,522 | 1,870,817 | | | | 1,870,817 |
| Smart Meter Entity Charge | 1551 | (169,846) | (2,676) | 26,813 | 486 | (3,215) | (148,438) | | | | (148,438) |
| RSVA - Wholesale Market Service Charge excluding CBR | 1580 | (6,947,648) | (198,549) | 7,283,689 | 163,032 | 7,553 | 308,076 | | | | 308,076 |
| RSVA - Wholesale Market Service Charge - CBR B | 1580 | (474,327) | (4,203) | (35,171) | (3,318) | (11,451) | (528,470) | | | | (528,470) |
| RSVA - Retail Transmission Network Charge | 1584 | 2,158,200 | 22,802 | (1,964,323) | (46,237) | 4,357 | 174,799 | | | | 174,799 |
| RSVA - Retail Transmission Connection Charge | 1586 | 4,587,506 | 65,349 | (48,373) | (4,733) | 102,017 | 4,701,766 | | | | 4,701,766 |
| RSVA - Power | 1588 | (3,834,544) | (35,256) | (319,684) | 10,550 | (93,366) | (4,272,300) | (370,191) | (8,320) | | (4,650,811) |
| **Sub-total not including RSVA Power Global Adjustment** | | (497,891) | (73,298) | 2,563,162 | 67,859 | 46,417 | 2,106,249 | (370,191) | (8,320) | | 1,727,738 |
| RSVA - Power Global Adjustment | 1589 | (3,053,546) | 77,181 | (5,395,918) | (161,593) | (189,902) | (8,723,779) | (538,732) | (12,108) | | (9,274,619) |
| **Total including RSVA Power Global Adjustment** | | (3,551,438) | 3,883 | (2,832,756) | (93,734) | (143,485) | (6,617,530) | (908,924) | (20,428) | | (7,546,881) |
| Disposition and Recovery/Refund of Regulatory Balances (2016) | 1595 | (13,771) | (167) | - | - | (309) | (14,247) | | | (14,247) | - |
| Disposition and Recovery/Refund of Regulatory Balances (2017) | 1595 | (28,398) | (39,328) | - | - | (638) | (68,364) | | | | (68,364) |
| Disposition and Recovery/Refund of Regulatory Balances (2018) | 1595 | (1,944,071) | (4,674) | - | - | (43,693) | (1,992,438) | | | (1,992,438) | - |
| **Total 1595** | | (1,986,240) | (44,169) | - | - | (44,641) | (2,075,049) | - | - | (2,006,685) | (68,364) |
| **Total Group 1** | | **(5,537,677)** | **(40,286)** | **(2,832,756)** | **(93,734)** | **(188,125)** | **(8,692,579)** | **(908,924)** | **(20,428)** | **(2,006,685)** | **(7,615,246)** |
| **Total Amount for Disposition** | | **(5,537,677)** | **(40,286)** | **(2,832,756)** | **(93,734)** | **(188,125)** | **(8,692,579)** | **(908,924)** | **(20,428)** | **(2,006,685)** | **(7,615,246)** |

Alectra Utilities is seeking a one-year disposition period for the Group 1 balances for the Enersource RZ. This approach is consistent with the EDDVAR Report which states on page 6 that "*the default disposition period used to clear the account balances through a rate rider should be one year"*.

**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. 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 ("CBR") Disposition**

Alectra Utilities has also established separate rate riders to dispose of the global adjustment ("GA") and Capacity Based Response ("CBR") balances for the Enersource RZ. These riders are applicable for non-RPP Class B customers only. Alectra Utilities' Class A customers are invoiced actual GA, therefore, none of the variance in the GA and CBR account balance should be attributed to these customers.

There were 27 Alectra Utilities customers in the Enersource RZ that newly qualified as Class A customers effective July 1, 2018, under the IESO's expansion of the Industrial Conservation Initiative ("ICI"). These customers paid GA and CBR as Class B customers up to and including June 30, 2018; and paid GA and CBR as Class A customers from July 1, 2018 to December 31, 2018. As such, these customers should be allocated only the portion of the GA and CBR account balances which accrued prior to their classification as Class A customers (i.e. from January 1, 2018 to June 30, 2018).

There were 6 Alectra Utilities customers in the Enersource RZ customer who ceased to qualify as a Class A customer effective July 1, 2018 under the IESO's expansion of the Industrial Conservation Initiative ("ICI"). These customers paid GA and CBR as Class A customers up to and including June 30, 2018; and paid GA and CBR as Class B customers from July 1, 2018 to December 31, 2018.

As such, these customers should be allocated only the portion of the GA and CBR account balances which accrued after their reclassification to Class B customers (i.e. from July 1, 2018 to December 31, 2018).

These GA and CBR amounts will be settled through twelve equal adjustments to bills as directed in the Chapter 3 Filing Requirements. These customers will not be charged the GA and CBR rate riders.

Table 75 below identifies the GA and CBR balances disposed of through rate riders and specific bill adjustments.

Alectra Utilities requests disposition of its total GA balance of ($9,274,619), of which ($8,759,646) will be disposed of via rate rider; and ($467,230) and ($47,744) will be disposed of via specific bill adjustments to the 27 new Class A customers and 6 new Class B customers respectively, as discussed above. Tabs "6A. GA Allocation Class A" in the IRM Model identifies the detailed calculation of the bill adjustments.

Alectra Utilities requests disposition of its total CBR balance of ($528,470), of which ($512,794) will be disposed of via rate rider; and ($14,223) and ($1,453) will be disposed of via specific bill adjustments to the 27 new Class A customers and 6 new Class B customers respectively, as discussed above. Tab "6.1a GA Allocation" in the IRM Model identifies the detailed calculation of the bill adjustments.

**Table 75 –Disposition of GA and CBR Balances – Enersource RZ**

| Description | Amount |
|---|---|
| Global Adjustment - Non-RPP Class B Customers Jan 1/2018- Dec 31/2018 | ($8,759,646) |
| Global Adjustment - New Class A Customers July 1/2018 | ($467,230) |
| Global Adjustment - New Class B Customers July 1/2018 | ($47,744) |
| **Class B Non-RPP Customers only - GA Rate Rider/Bill Adjustment** | **($9,274,619)** |
| Capacity Based Recovery - Non-RPP Class B Customers Jan 1/2018- Dec 31/2018 | ($512,794) |
| Capacity Based Recovery - New Class A Customers July 1/2018 | ($14,223) |
| Capacity Based Recovery - New Class B Customers July 1/2018 | ($1,453) |
| **Class B Non-RPP Customers only - CBR Rate Rider/Bill Adjustment** | **($528,470)** |

A summary of the rate riders applicable to each group of customers is identified in Table 76 below.

**Table 76 – Rate Riders by Customer Group – Enersource RZ**

| Customers | DVA Rate Rider 1 [1] | DVA Rate Rider 2 [2] | CBR B Rate Rider | GA Rate Rider | GA/CBR Bill Adjustment |
|---|---|---|---|---|---|
| WMPs | x | | | | |
| Class A (Jan 1, 2018 - Dec 31, 2018) | x | x | | | |
| Class B non-RPP (Jan 1, 2018 - Jun 30, 2018)/Class A (Jul 1, 2018 - Dec 31, 2018) Customers | x | x | | | x |
| Class A non-RPP (Jan 1, 2018 - Jun 30, 2018)/Class B (Jul 1, 2018 - Dec 31, 2018) Customers | x | x | | | x |
| Class B non-RPP (Jan 1, 2018 - Dec 31, 2018) Customers | x | x | x | x | |
| Class B RPP Customers | x | x | x | | |

1. DVA Rate Rider 1 = disposition of low voltage, SME, Network, Connection, IRM balances
2. DVA Rate Rider 2 = disposition of Power and Wholesale Market Service Charges (excluding CBR)

WMPs are charged DVA Rate Rider 1 only, which includes account balances for low voltage charges, retail transmission network charges, retail transmission connection charges.

Class A customers (who were Class A from January 1 – December 31, 2018) are charged the sum of DVA Rate Rider 1 and DVA Rate Rider 2, the latter of which includes account balances for power and wholesale market service charges excluding CBR.

Class B, non-RPP customers (who were Class A customers for only a part of 2018) are charged the sum of DVA Rate Rider 1 and DVA Rate Rider 2; and a bill adjustment for their portion of the GA and CBR account balances.

Class A, non-RPP customers (who were Class B customers for only part of 2018) are charged the sum of DVA Rate Rider 1 and DVA Rate Rider 2; and a bill adjustment for their portion of the GA and CBR account balances.

Class B, non-RPP customers (who were Class B from January 1 – December 31, 2018) are charged the sum of DVA Rate Riders 1 and 2; the GA Rate Rider; and the CBR B Rate Rider

Class B RPP customers are charged the sum of DVA Rate Riders 1 and 2; and the CBR B Rate Rider.

The Group 1 DVAs disposition by customer group is identified in Table 77, below.

**Table 77 – Group 1 DVAs Disposition by Customer Group – Enersource RZ**

| Description | Account | Amount |
|---|---|---|
| Low Voltage | 1550 | $1,870,817 |
| Smart Meter Entity Charge (Residential and GS<50kW Classes Only) | 1551 | ($148,438) |
| Retail Transmission Network Charge | 1584 | $174,799 |
| Retail Transmission Connection Charge | 1586 | $4,701,766 |
| Disposition and Recovery/Refund of Regulatory Balances | 1595 | ($68,364) |
| **All Customers - DVA Rate Rider 1** | | **$6,530,579** |
| | | |
| Power | 1588 | ($4,650,811) |
| Wholesale Market Service Charge excluding CBR | 1580 | $308,076 |
| **All Customers ex WMPs - DVA Rate Rider 2** | | **($4,342,735)** |
| | | |
| Wholesale Market Service Charge - CBR Class B | 1580 | ($512,315) |
| Wholesale Market Service Charge - New Class A/B Customers July 1/2018 | 1580 | ($16,155) |
| **All Class B Customers ex WMPs - CBR B Bill Adjustment** | **1580** | **($528,470)** |
| | | |
| Global Adjustment - Non-RPP Class B Customers Jan 1/2018 -Dec 31/2018 | 1589 | ($8,729,371) |
| Global Adjustment - New Class A/B Customers July 1/2018 | 1589 | ($545,248) |
| **Class B Non-RPP Customers only - GA Rate Rider/Bill Adjustment** | | **($9,274,619)** |
| | | |
| **Total (Repayment to)/Recovery from Customers** | | **($7,615,246)** |
| Disposition via Rate Rider | | ($7,053,842) |
| Disposition via Customer Specific Bill Adjustments - GA for Class A customers only a portion of 2018 | | ($545,248) |
| Disposition via Customer Specific Bill Adjustments - CBR for Class A/B customers only a portion of 2018 | | ($16,155) |

All balances claimed are allocated to the rate classes based on the default cost allocation methodology as identified in the EDDVAR report. The 2018 actuals reported in Alectra Utilities 2018 RRRs have been used to calculate the rate riders as per the Chapter 3 Filing Requirements issued by the OEB on July 12, 2018.

The billing determinants, billing adjustments and calculation of the rate riders are provided in Tabs 4 through 8 in the IRM Model filed as Attachment 15. Table 78 below summarizes the deferral and variance rate riders by class.

**Table 78 – Deferral and Variance Account Riders – Enersource RZ**

| Customer Class | Deferral/Variance Account Rate Rider | | Deferral/Variance Account Rate Rider for Non-WMP | | Global Adjustment Rate Rider Non-RPP Class B | | CBR B Rate Rider Class B Consumer | |
|---|---|---|---|---|---|---|---|---|
| | $/kWh | $/kW | $/kWh | $/kW | $/kWh | $/kW | $/kWh | $/kW |
| Residential | 0.0002 | | | | (0.0032) | | (0.0001) | |
| General Service Less Than 50 kW | 0.0003 | | | | (0.0032) | | (0.0001) | |
| General Service 50 To 499 kW | | 0.3300 | | (0.2152) | (0.0032) | | | (0.0352) |
| General Service 500 To 4,999 kW | | 0.4084 | | (0.2659) | (0.0032) | | | (0.0408) |
| Large Use | | 0.1787 | | | 0.0000 | | | 0.0000 |
| Unmetered Scattered Load | 0.0003 | | | | (0.0032) | | (0.0001) | |
| Street Lighting | | 0.1021 | | | (0.0032) | | | (0.0321) |

Alectra Utilities requests disposition of the Enersource RZ adjusted Group 1 balances of ($7,615,246) identified in Table 72, through the rate riders identified in Table 78, above.

**GA Analysis Workform**

The GA Analysis Workform ("GA Workform") for the Enersource RZ is filed as Attachment 23. The GA Workform compares the principal activity in the general ledger for Account 1589, Global Adjustment to the expected principal balance based on monthly GA volumes, revenue and costs. The GA workform provides a tool to assess if the principal activity in Account 1589 for a specific year is reasonable.

The principal activity in Account 1589 recorded in 2018 was ($8,449,465) as identified in Table 79 below. The principal activity balance, after known adjustments of ($538,732) was ($8,988,197). This is compared to the expected principal balance in Account 1589 of ($6,507,222) calculated in Attachment 23, which results in an unreconciled difference of ($2,480,975). This represents (0.89%) of Alectra Utilities 2018 IESO purchases in the Enersource RZ, which is within the OEB's threshold (+/- 1% of IESO purchases).

**Table 79 – GA Workform Summary**

| Description | Amount |
|---|---|
| **Principal Activity in RSVA(GA)** | ($8,449,465) |
| Add Known Adjustments | ($538,732) |
| **Adjusted Principal Activity in RSVA(GA)** | ($8,988,197) |
| **Expected Principal Activity in RSVA(GA)** | ($6,507,222) |
| **Variance $** | ($2,480,975) |
| Total 2018 IESO Purchases | $280,327,738 |
| **Absolute Variance as a % of IESO Purchases** | -0.89% |

## 1595 Analysis Workform

The 1595 Analysis Workform ("1595 Workform") for the Enersource RZ, is filed as Attachment 24. The 1595 Workform compares the principal and interest amounts previously approved for disposition to the residual balances remaining after the amounts have been recovered or refunded to customers through rate riders. As discussed in the Chapter 3 Filing Requirements, *"the balances in Account 1595 will first be assessed in two groups of accounts; one being the amounts attributable to GA, and the other being the remainder of Group 1 and Group 2 Accounts (if applicable). A residual balance in either of the two groups of accounts exceeding +/- 10% of the original amounts previously approved for disposition would be considered material."* The 1595 workform provides a tool to assess if the residual balance in Account 1595 for a specific year is reasonable. Distributors can only seek disposition of the audited account balances in Account 1595, a year after the rate rider's sunset date has expired.

Alectra Utilities request disposition of its Account 1595 (2017) residual balance for the Enersource RZ. The total Group 1 and Group 2 balances excluding Account 1589; and the balance in Account 1589 – Global Adjustment generates a variance of 1.8% and 4.0% respectively, which is within the OEB's threshold of +/- 10%.

**Table 80 – 1595 Workform Summary**

| Description | Total Balances Approved for Disposition | Residual Balances | Collections/ Returns Variance (%) |
|---|---|---|---|
| Total Group 1 and Group 2 Balances excluding Account 1589 | ($12,464,655) | ($225,918) | 1.8% |
| Account 1589 - Global Adjustment | $4,961,627 | $197,520 | 4.0% |
| **Total Group 1 and Group 2 Balances** | **($7,503,028)** | **($28,398)** | **0.4%** |

**<u>Guelph Hydro RZ</u>**

The Group 1 balances as of December 31, 2018, in the amount of $3,446,337 have been adjusted for the following items to determine the amount for disposition of ($1,226,282) as identified in Table 81, below:

- Only residual balances in Account 1595 for which rate riders have expired are included;
- RPP settlement true-up claims for a given fiscal year that have not been included in the audited financial statements have been 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*". Consequently, the account balances on Tab 3. Continuity Schedule differ from the annual RRR filing;
- 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 projected carrying charges to December 31, 2019).

**Table 81 – Group 1 Balances for Disposition – Guelph Hydro RZ**

| Description | Amount |
|---|---|
| **Group 1 Account Balances as of December 31, 2018** | **$3,446,337** |
| Subtract 2018 Annual Filing Disposition (EB-2018-0036) - Refund to Customers | $5,571,133 |
| RPP Settlement True-up Claims Adjustment | $1,003,652 |
| Add Projected Carrying Charges | ($36,991) |
| Deduct 1595 Residual Balances to be disposed in a future rate proceeding | $68,147 |
| **Adjusted Group 1 Account Balances for Disposition - Refund to Customers** | **($1,226,282)** |

Alectra Utilities has computed the disposition threshold for the Guelph Hydro RZ, based on the adjusted Group 1 balances to be ($0.0007/kWh), which is below the OEB's pre-set disposition threshold, as identified in Table 82, below. Alectra Utilities does not request disposition of its Group 1 account balances in this Annual Filing for the Guelph Hydro RZ.

**Table 82 - Calculation of Disposition Threshold – Guelph Hydro RZ**

| Description | Account | Amount |
|---|---|---|
| Low Voltage | 1550 | $145,854 |
| Smart Meter Entity Charge | 1551 | ($74,858) |
| RSVA - Wholesale Market Service Charge excluding CBR | 1580 | ($1,881,766) |
| RSVA - Wholesale Market Service Charge - Capacity Based Recovery ("CBR") Class B | 1580 | ($18,547) |
| RSVA - Retail Transmission Network Charge | 1584 | $1,683,701 |
| RSVA - Retail Transmission Connection Charge | 1586 | $2,278,636 |
| RSVA - Power | 1588 | ($198,686) |
| RSVA - Global Adjustment | 1589 | $968,244 |
| Disposition and Recovery/Refund of Regulatory Balances | 1595 | $543,759 |
| **Group 1 Account Balances as of December 31, 2018** | | **$3,446,337** |
| Subtract 2018 Annual Filing Disposition (EB-2018-0036) - Refund to Customers | | $5,571,133 |
| RPP Settlement True-up Claims Adjustment | | $1,003,652 |
| Add Projected Carrying Charges | | ($36,991) |
| Deduct 1595 Residual Balances to be disposed in a future rate proceeding | | ($68,147) |
| **Adjusted Group 1 Account Balances for Disposition - Refund to Customers** | | **($1,226,282)** |
| 2018 kWhs | | 1,678,459,496 |
| **Threshold Test $/kWh** | | **($0.0007)** |

**Exhibit 3, Tab 1, Schedule 8**

**Settlement Process with the IESO**

## SETTLEMENT PROCESS WITH THE IESO

The Board's Chapter 3 Filing Requirements requires each distributor to provide a description of its settlements process with the IESO or host distributor. Distributors must specify the Global Adjustment rate used when billing customers for each rate class, itemize the process for providing consumption estimates to the IESO, and describe the true-up process to reconcile estimates of RPP and non-RPP consumption once actuals are known. Horizon Utilities RZ provides the settlement process below.

The manner in which Alectra Utilities settles with the IESO is provided in Table 83 below and depends on the following: (i) whether the customer is a Regulated Price Plan ("RPP") consumer; and (ii) whether the customer is a Class A or Class B consumer. It is not dependent on the rate class.

**Table 83 – Settlement Process with the IESO**

| Customer | GA Rate used for Billing | GA Rate used to Record Cost | Settlement Process | Consumption Estimates | Impact on GA Variance Account |
|---|---|---|---|---|---|
| Class A | Actual | Actual | Alectra Utilities pays the IESO Actual GA and bills customers Actual GA - no further settlement with the IESO is required | Class A consumption actuals are submitted to the IESO - actuals are known at the time of submission; therefore an estimate is not required | none |
| Class B non-RPP | 1st Estimate | Actual | Alectra Utilities pays the IESO Actual GA and bills customers 1st estimate GA - no further settlement with the IESO is required | Class B non-RPP consumption is not submitted to the IESO; however an estimate is used in order to calculate the RPP consumption used in the RPP vs. Market Price Claim[2] | Difference between revenues and costs recorded to GA variance account on a monthly basis and recovered from/repaid to Class B non-RPP consumers on disposal of the GA Variance Account |
| Class B RPP | RPP Time-of-Use ("TOU") or Tiered Rates[1] | Actual | Alectra Utilities pays the IESO Actual GA and bills customers RPP rates - Alectra Utilities settles with the IESO on an monthly basis via the RPP vs. Market Price Claim[2] | RPP consumption is estimated and provided to the IESO as part of the RPP vs. Market Price Claim[2] provided to the IESO | none |

1. GA is not billed separately for Class B RPP customers; incorporated into RPP Rates
2. RPP vs. Market Price Claim is discussed in further detail below

**<u>Class A Customers</u>:** The IESO publishes the actual GA for a month on the tenth business day of the following month. The GA costs invoiced to Alectra Utilities by the IESO represents the total provincial system-wide GA costs for the month multiplied by Alectra Utilities' peak demand factor, which is the aggregate of its Class A customers' peak demand factors. No further settlement with the IESO is required. Alectra Utilities bills Class A customers the GA based on their respective peak demand factors or their percentage contribution to the top five peak Ontario demand hours, and as such, there is no variance in the GA account balance attributed to these customers. Alectra Utilities submits total Class A actual consumption to the IESO on a monthly basis as part of the monthly RPP vs Market Claim submission.

**Class B non-RPP Customers:** Class B non-RPP customers are billed by Alectra Utilities throughout the month. These customers pay the spot market price for energy – either the Weighted Average Hourly Spot price ("WAHSP") or the Hourly Ontario Energy Price ("HOEP"); and the GA. Alectra Utilities bills its Class B non-RPP customers using the IESO's 1st estimate for GA for the month which is published by the IESO on the last business day of the preceding month. Alectra Utilities confirms that the GA rate that is used is applied consistently for all billing and unbilled revenue transactions for non-RPP Class B customers.

Alectra Utilities pays the IESO Class B GA based on its actual Class B volume at the actual Class B rate. No further settlement with the IESO is required. Any difference between GA revenues and GA costs are recorded in the GA variance account to be recovered from or refunded to Class B non-RPP customers. Alectra Utilities allocates the Class B GA charged by the IESO to its RPP and non-RPP customers based on consumption. Class B non-RPP consumption is equal to the consumption for all customers billed at spot pricing (interval metered and non-interval metered) less the consumption for Class A customers.

The determination of Class B RPP consumption is discussed in further detail below.

**Class B RPP Customers:** Class B RPP customers are billed by Alectra Utilities throughout the month at RPP TOU or Tiered Rates. The difference between the amount recovered from RPP customers at TOU or Tiered Rates and the amount paid for the commodity supply in the wholesale marketplace to the IESO, is recorded and managed in an account by the IESO.

On a monthly basis, Alectra Utilities compares the amount collected from RPP customers (kWh billed at TOU or Tiered Pricing) to the amount it pays to the IESO , to determine this amount ("the RPP vs. Market Price claim").

Alectra Utilities provides a summary of its RPP vs. Market Price settlement process by rate zone, below.

Horizon Utilities RZ

There are three components to the RPP vs. Market Price claim:

1. Estimated Claim for the Current Month (based on Estimated Purchases and Energy Prices)
2. True-up of Prior Month Claim using Actual Purchases and Energy Prices
3. True-up of "Current Month (3-month lag)" Claim using Actual Billed Consumption

1. Estimated Claim for the Current Month (based on Estimated Purchases and Energy Prices)

Eligible kWh, for the purposes of calculating the RPP vs. Market price claim, is the actual billed consumption for RPP customers on a monthly basis. Since actual billed consumption is not available until three months post consumption due to a billing lag, Alectra Utilities estimates the eligible kWh for the Horizon Utilities RZ using wholesale power purchased from the IESO for the current month and makes an adjustment to reflect billed kWh three months later.

Eligible kWh includes embedded generation and is defined as the following:

**Total kWh wholesale power purchased from the IESO**

**Add:** Embedded Generation

**Less:** kWh Consumption for Interval Metered Customers billed at Spot

**Less:** Billed kWh for Non-Interval Metered Customers billed at Spot (monthly consumption is not available from the billing system for these customers so billed kWh is used as a proxy for consumption.

2. True-up of Prior Month Claim using Actual Purchases and Energy Prices

In the month after the RPP vs. Market Price claim is submitted, more accurate information is available to determine the claim. The prior month's claim is recalculated using updated values for purchases and energy prices. The differences between the current month's claim and the re-estimated claim is submitted in the subsequent month (e.g., re-estimated claim for April is submitted as part of the May RPP vs. Market Price Claim). Although this results in a more accurate claim amount, eligible kWhs are still based on purchases not actual consumption. The RPP vs. Market Price claim is trued up three months later when consumption is available from the billing system.

3. True-up of "Current Month (3-month lag)" Claim using Actual Billed Consumption

The original estimate and revised estimate of eligible kWh and associated dollar amounts are based on a top-down estimate of RPP consumption using wholesale power purchased. The Horizon Utilities RZ billing system is used to determine the actual kWh consumed by and billed to RPP customers. This information is not available until three months after the claim has been submitted to the IESO (there is a time lag between consumption and billing which is dependent upon a customer's meter read cycle and billing frequency). The true-up of the original estimate based on power purchased occurs one month after the original claim is filed. The final true-up based on actual billed consumption occurs three months after the original claim is filed as identified in Table 84 below. The final true-up claim is calculated using actual billed kWh consumption by category (TOU or Tiered pricing) and actual RPP, WAHSP and GA rates. This claim is compared to the true-up for that month's claim and the difference is included in the RPP vs. Market Price Claim submission to the IESO.

**Table 84 – Timing of RPP vs. Market Claim True-up – Horizon Utilities RZ**

| April Submission | Original Claim | Revised Claim True-Up | Actual Claim True-Up |
|---|---|---|---|
| Period | April | May | July |

The billed kWh consumption and corresponding dollar values are available from Alectra Utilities' billing system in the Horizon Utilities RZ. These are allocated by month based on the customer's meter read date range – it is assumed that consumption occurs evenly over the period (same kWh usage and dollar per day). Although kWh consumption by hour is available from smart meters it is not available in the billing system; or aggregated elsewhere.

The calculation is performed three months subsequent to the customer's consumption to ensure that 100% of consumption for a particular month is captured (for example, after three months, 100% of consumption for April will have been billed by July). Similar to the true-up for the prior month's claim discussed previously, the actual claim is calculated using actual billed kWh consumption by category (TOU or Tiered pricing) and actual RPP, WAHSP and GA rates. This claim is compared to the true-up for that month's claim and the difference is included in the RPP vs. Market Price Claim submission to the IESO.

**Internal Controls for RPP Settlement**

The Load Profiling and Settlement System ("LPSS") facilitates the wholesale settlement and interval billing functions within the utility, and is the key driver in the estimation of consumption used in the RPP settlement process. Alectra Utilities has incorporated various internal control checks in its estimation of RPP consumption. Alectra Utilities meter read consumption data is subject to a number of Validating, Estimation and Editing ("VEE") control checks through several data flow subsystems (MV90 and Centralized Meter Data Engine "CMDE") within the data hierarchy prior to upload to LPSS.

The MV90 system collects and validates interval data from MIST meters. MV90 meter data is checked for completeness, accuracy, access and metering issues that may affect the capturing and export of data to LPSS. MV90 VEE control checks include, but are not limited to: gaps in data; high/low and spike checks; power outages; and loss of phase. The CMDE stores all meter data from MV90 and Advanced Metering Infrastructure ("AMI") meters. CMDE VEE control checks include; but are not limited to: missing intervals; demand checks; and spike checks; and ensures that meter data is as correct and as complete as possible. Finallly, VEE is also performed in LPSS which includes: high/low and spike checks; gaps; and totalization checks.

In addition to the above controls on the validation of meter data, all energy purchases billed by the IESO are subject to a number of internal control checks to ensure the accuracy and completeness of data flows. This includes the comparison of: IESO purchases with totalized meter read consumption; preliminary statement values with IESO energy purchases; and final statement values with preliminary statement values. Once these checks are completed, the estimated data is incorporated into Alectra Utilities' unbilled calculation for determining estimated RPP consumption.

On a monthly basis, unbilled revenue is based on a combination of actual usage at the end of the reporting period and an estimate of unbilled electricity distribution services supplied to customers between the date of the last meter reading and the period ending date.

Actual RPP consumption and costs used in the RPP true up process is based on actual billed consumption and the actual cost of commodity and GA to determine the true up value for settlement with the IESO. Once the actual true up is computed for settlement with the IESO, an additional independent calculation of the true up is completed to verify the difference between the estimated and the actual true up calculation. The true up is then incorporated into the current month's RPP settlement claim with the IESO and recorded in the monthly Cost of Power accrual.

**Brampton RZ**

There are two components to the RPP vs. Market Price claim:

1. Estimated RPP settlement amount for the current month; and
2. A true-up adjustment to the RPP settlement amount for the prior month (the difference between the actual and estimated RPP settlement amounts for the prior month)

1. Estimated RPP settlement amount for the current month

- Estimated total kWhs of commodity purchased for the month and the associated dollars based on Spot Market Price.
- The billing statistics for the current month of the prior year are used as the estimate of the percentage of volumes billed to customers at Spot Market Prices. This percentage is used to allocate the volumes billed to customers based on Spot Market prices, and those billed on RPP prices.
- The volumes billed to customers at RPP rates is then allocated across the various RPP price Tiers and TOU price blocks. The kWh allocation %s are estimated based on the actual percentage ratios from the billing statistics for the current month of the prior year.
- The quantities for each Tier/TOU price block are multiplied by the average spot market price purchased.
- As the actual wholesale GA rate for the month is not available at the time of the calculation, the 2nd estimate GA rate provided by IESO for the current month is used to calculate the GA portion of the settlement calculations.
- The Energy at Spot Market Price and the GA represents an estimate of what the IESO will bill Alectra Utilities for the Brampton RZ for the month.
- The OEB approved RPP prices are multiplied by the volumes estimated for each of the Tier/TOU price blocks and represents an estimate of the amount to be billed to RPP customers for the commodity and GA.
- The current month estimated Settlement is the difference between 1) the estimated Commodity plus GA to be billed by the IESO for the RPP customers, and 2) the estimated power billed by Alectra Utilities Brampton RZ to RPP customers.

2. <u>True-up adjustment to the RPP settlement amount</u>

- The billing statistics for the prior month of the current year for the percentage of volumes billed to customers at Spot Market Prices is used,
- The billing statistics for the prior month of the current year for the actual kWh allocation %'s for each Tier/TOU price Block are used, and
- The actual Class B GA rate for the prior month is used.
- The actual RPP claim calculated for the prior month is compared to the prior month's estimate to determine the true-up adjustment.

**Table 85 – Timing of RPP vs. Market Claim True-up – Brampton RZ**

| Period Covered | Original Claim | Actual Claim True-Up |
|---|---|---|
| April | April | May |

**<u>Internal Controls for RPP Settlement</u>**

The Load Profiling and Settlement System ("LPSS") facilitates the wholesale settlement and interval billing functions within the utility, and is the key driver in the estimation of consumption used in the RPP settlement process. Alectra Utilities has incorporated various internal control checks in its estimation of RPP consumption. Alectra Utilities meter read consumption data is subject to a number of Validating, Estimation and Editing ("VEE") control checks through several data flow subsystems (MV90 and Centralized Meter Data Engine "CMDE") within the data hierarchy prior to upload to LPSS.

The MV90 system collects and validates interval data from MIST meters. MV90 meter data is checked for completeness, accuracy, access and metering issues that may affect the capturing and export of data to LPSS. MV90 VEE control checks include, but are not limited to: gaps in data; high/low and spike checks; power outages; and loss of phase. The CMDE stores all meter data from MV90 and Advanced Metering Infrastructure ("AMI") meters. CMDE VEE control checks include; but are not limited to: missing intervals; demand checks; and spike checks; and ensures that meter data is as correct and as complete as possible. Finallly, VEE is also performed in LPSS which includes: high/low and spike checks; gaps; and totalization checks.

In addition to the above controls on the validation of meter data, all energy purchases billed by the IESO are subject to a number of internal control checks to ensure the accuracy and completeness of data flows. This includes the comparison of: IESO purchases with totalized meter read consumption; preliminary statement values with IESO energy purchases; and final statement values with preliminary statement values. Once these checks are completed, the estimated data is incorporated into Alectra Utilities' unbilled calculation for determining estimated RPP consumption.

On a monthly basis, unbilled revenue is based on a combination of actual usage at the end of the reporting period and an estimate of unbilled electricity distribution services supplied to customers between the date of the last meter reading and the period ending date.

Actual RPP consumption and costs used in the RPP true up process is based on actual billed consumption and the actual cost of commodity and GA to determine the true up value for settlement with the IESO. Once the actual true up is computed for settlement with the IESO, an additional independent calculation of the true up is completed to verify the difference between the estimated and the actual true up calculation. The true up is then incorporated into the current month's RPP settlement claim with the IESO and recorded in the monthly Cost of Power accrual.

**PowerStream RZ**

There are two components to the RPP vs. Market Price claim:

1. Estimated Claim for the Current Month
2. True-up of “Current Month (2-month lag)” Claim using Actual Billed Consumption

1. Estimated Claim for the Current Month

Eligible kWh, for the purposes of calculating the RPP vs. Market price claim, is the actual billed consumption for RPP customers on a monthly basis. Since actual billed consumption is not available until two months post consumption due to a billing lag, Alectra Utilities estimates the eligible kWh from each RPP customer’s most recent bill, for the PowerStream RZ, prorating based on the number of days to get the kWh consumption by each RPP rate level for the target month. Alectra Utilities uses this consumption to calculate the RPP revenue at RPP rates and the RPP cost to determine the RPP claim for the current month for the PowerStream RZ. RPP cost consists of the commodity cost and the GA cost. Commodity cost is calculated as the RPP kWhs multiplied by the weighted average hourly Ontario price based on the net system load for the target month. GA cost is calculated as the RPP kWhs multiplied by the GA 2$^{nd}$ estimate from IESO.

2. True-up of “Current Month (2-month lag)” Claim using Actual Billed Consumption

The original estimate of eligible kWh and associated dollar amounts are based on the customers’ bills and best cost information available at the time of filing the claim including GA cost at 2$^{nd}$ estimate rather than actual GA cost. Alectra Utilities’ PowerStream RZ billing system is used again two months after the claim has been submitted to the IESO to determine the actual kWh consumed by and billed to RPP customers (there is a time lag between consumption and billing which is dependent upon a customer’s meter read cycle and billing frequency). The final true-up based on actual billed consumption and actual cost of commodity and GA occurs two months after the original claim is filed as identified in Table 86, below.

**Table 86 – Timing of RPP vs. Market Claim True-up – PowerStream RZ**

| Period Covered | Original Claim | "Actual" Claim True-up |
|---|---|---|
| April | April | June |

The actual billed kWh consumption and corresponding dollar values (revenues and costs) are available from Alectra Utilities' billing system in the PowerStream RZ. These are allocated to the target month based on the customer's bills that contain consumption for that month based on the meter read date range. It is assumed that consumption occurs evenly over the billing period (same kWh usage and dollar per day). Although kWh consumption by hour is available from smart meters it is not available in the billing system; or aggregated elsewhere. The calculation is performed two months subsequent to the customer's consumption to ensure that 100% of consumption for a particular month is captured (for example, after two months, 100% of consumption for November 2017 will have been billed by January 31 , 2018). The actual claim is calculated using actual billed kWh consumption by category (TOU or Tiered pricing) and actual RPP, WAHSP and GA rates. This claim is compared to that month's claim and the difference is included in the RPP vs. Market Price Claim submission to the IESO.

## Internal Controls for RPP Settlement

The Load Profiling and Settlement System ("LPSS") facilitates the wholesale settlement and interval billing functions within the utility, and is the key driver in the estimation of consumption used in the RPP settlement process. Alectra Utilities has incorporated various internal control checks in its estimation of RPP consumption. Alectra Utilities meter read consumption data is subject to a number of Validating, Estimation and Editing ("VEE") control checks through several data flow subsystems (MV90 and Centralized Meter Data Engine "CMDE") within the data hierarchy prior to upload to LPSS.

The MV90 system collects and validates interval data from MIST meters. MV90 meter data is checked for completeness, accuracy, access and metering issues that may affect the capturing and export of data to LPSS. MV90 VEE control checks include, but are not limited to: gaps in data; high/low and spike checks; power outages; and loss of phase. The CMDE stores all meter data from MV90 and Advanced Metering Infrastructure ("AMI") meters. CMDE VEE control checks include; but are not limited to: missing intervals; demand checks; and spike checks; and ensures that meter data is as correct and as complete as possible. Finallly, VEE is also performed in LPSS which includes: high/low and spike checks; gaps; and totalization checks.

In addition to the above controls on the validation of meter data, all energy purchases billed by the IESO are subject to a number of internal control checks to ensure the accuracy and completeness of data flows. This includes the comparison of: IESO purchases with totalized meter read consumption; preliminary statement values with IESO energy purchases; and final statement values with preliminary statement values. Once these checks are completed, the estimated data is incorporated into Alectra Utilities' unbilled calculation for determining estimated RPP consumption.

On a monthly basis, unbilled revenue is based on a combination of actual usage at the end of the reporting period and an estimate of unbilled electricity distribution services supplied to customers between the date of the last meter reading and the period ending date.

Actual RPP consumption and costs used in the RPP true up process is based on actual billed consumption and the actual cost of commodity and GA to determine the true up value for settlement with the IESO. Once the actual true up is computed for settlement with the IESO, an additional independent calculation of the true up is completed to verify the difference between the estimated and the actual true up calculation. The true up is then incorporated into the current month's RPP settlement claim with the IESO and recorded in the monthly Cost of Power accrual.

**Enersource RZ**

There are two components to the RPP vs. Market Price claim:

1. Estimated Claim for the Current Month
2. True-up of "Current Month (2-month lag)" Claim using Actual Billed Consumption

1. Estimated Claim for the Current Month

Eligible kWh, for the purposes of calculating the RPP vs. Market price claim, is the actual billed consumption for RPP customers on a monthly basis. Since actual billed consumption is not available until two months post consumption due to a billing lag, Alectra Utilities estimates the eligible kWh from each RPP customer's most recent bill, for the Enersource RZ, prorating based on the number of days to get the kWh consumption by each RPP rate level for the target month. Alectra Utilities uses this consumption to calculate the RPP revenue at RPP rates and the RPP cost to determine the RPP claim for the current month for the Enersource RZ. RPP cost consists of the commodity cost and the GA cost. Commodity cost is calculated as the RPP kWhs multiplied by the weighted average hourly Ontario price based on the net system load for the target month. GA cost is calculated as the RPP kWhs multiplied by the GA 2$^{nd}$ estimate from IESO.

2. True-up of "Current Month (2-month lag)" Claim using Actual Billed Consumption

The original estimate of eligible kWh and associated dollar amounts are based on the customers' bills and best cost information available at the time of filing the claim including GA cost at 2$^{nd}$ estimate rather than actual GA cost. Alectra Utilities' Enersource RZ billing system is used again two months after the claim has been submitted to the IESO to determine the actual kWh consumed by and billed to RPP customers (there is a time lag between consumption and billing which is dependent upon a customer's meter read cycle and billing frequency). The final true-up based on actual billed consumption and actual cost of commodity and GA occurs two months after the original claim is filed as identified in Table 87, below.

**Table 87 – Timing of RPP vs. Market Claim True-up – Enersource RZ**

| Period Covered | Original Claim | "Actual" Claim True-up |
|---|---|---|
| April | April | June |

The actual billed kWh consumption and corresponding dollar values (revenues and costs) are available from Enersource RZ's billing system. These are allocated to the target month based on the customer's bills that contain consumption for that month based on the meter read date range. It is assumed that consumption occurs evenly over the billing period (same kWh usage and dollar per day). Although kWh consumption by hour is available from smart meters it is not available in the billing system; or aggregated elsewhere. The calculation is performed two months subsequent to the customer's consumption to ensure that 100% of consumption for a particular month is captured (for example, after two months, 100% of consumption for November 2017 will have been billed by January 31, 2018). The actual claim is calculated using actual billed kWh consumption by category (TOU or Tiered pricing) and actual RPP, WAHSP and GA rates. This claim is compared to that month's claim and the difference is included in the RPP vs. Market Price Claim submission to the IESO.

**<u>Internal Controls for RPP Settlement</u>**

The Load Profiling and Settlement System ("LPSS") facilitates the wholesale settlement and interval billing functions within the utility, and is the key driver in the estimation of consumption used in the RPP settlement process. Alectra Utilities has incorporated various internal control checks in its estimation of RPP consumption. Alectra Utilities meter read consumption data is subject to a number of Validating, Estimation and Editing ("VEE") control checks through several data flow subsystems (MV90 and Centralized Meter Data Engine "CMDE") within the data hierarchy prior to upload to LPSS.

The MV90 system collects and validates interval data from MIST meters. MV90 meter data is checked for completeness, accuracy, access and metering issues that may affect the capturing and export of data to LPSS. MV90 VEE control checks include, but are not limited to: gaps in data; high/low and spike checks; power outages; and loss of phase. The CMDE stores all meter data from MV90 and Advanced Metering Infrastructure ("AMI") meters. CMDE VEE control checks include; but are not limited to: missing intervals; demand checks; and spike checks; and ensures that meter data is as correct and as complete as possible. Finallly, VEE is also performed in LPSS which includes: high/low and spike checks; gaps; and totalization checks.

In addition to the above controls on the validation of meter data, all energy purchases billed by the IESO are subject to a number of internal control checks to ensure the accuracy and completeness of data flows. This includes the comparison of: IESO purchases with totalized meter read consumption; preliminary statement values with IESO energy purchases; and final statement values with preliminary statement values. Once these checks are completed, the estimated data is incorporated into Alectra Utilities' unbilled calculation for determining estimated RPP consumption.

On a monthly basis, unbilled revenue is based on a combination of actual usage at the end of the reporting period and an estimate of unbilled electricity distribution services supplied to customers between the date of the last meter reading and the period ending date.

Actual RPP consumption and costs used in the RPP true up process is based on actual billed consumption and the actual cost of commodity and GA to determine the true up value for settlement with the IESO. Once the actual true up is computed for settlement with the IESO, an additional independent calculation of the true up is completed to verify the difference between the estimated and the actual true up calculation. The true up is then incorporated into the current month's RPP settlement claim with the IESO and recorded in the monthly Cost of Power accrual.

**<u>Guelph Hydro RZ</u>**

Alectra Utilities billing system in the Guelph RZ captures RPP prices coincidently with the corresponding Weighted Average Hourly Spot Price ("WAHSP"). Although only RPP prices are charged and presented on the RPP customers' bills, the billing system tracks the WAHSP corresponding to RPP consumption and RPP charges. This billing structure allows a perfect settlement as it relates to the difference of RPP minus WAHSP. Therefore, Alectra Utilities prepares the monthly RPP settlement (RPP minus WAHSP) for the Guelph RZ, using billed RPP consumption available in Guelph RZ's Customer Information System (CIS). As a result, Guelph RZ does not true-up for this portion of the RPP settlement (i.e. RPP minus WAHSP).

The GA is trued-up based on billed and unbilled consumption multiplied by the difference between the 2nd estimate GA rate (used in RPP settlement submission) and the Actual GA rate.

In Alectra Utilities predecessor, Guelph Hydro's 2018 IRM proceedings (EB-2017-0044), Guelph Hydro recognized the need to develop a method for identifying consumption attributed to each month. A query was developed which uses the year-end mass rate change of December 31 to identify consumption for the month of December that was billed in the calendar month of January. Currently this query functions only on a mass rate change date. Alectra Utilities trued-up to the actual RPP consumption using the mass year-end rate change query and corrected the GA true-up in January 2018. This GA true-up process was repeated in January 2019.

<u>Method for Estimating RPP & non-RPP consumption and Treatment of Embedded Generation & Embedded Distributor Volumes</u>

As previously stated, Alectra Utilities prepared the 2018 RPP settlement (RPP minus WAHSP) based on billed RPP consumption volumes, and corrected the GA true-up to load-month in January 2019 by using a mass year-end rate change query.

Alectra Utilities gathers billed embedded generation volumes to complete the IESO's monthly RESOP, microFIT, and FIT settlements in the Guelph RZ, and maintains a General Ledger account for each contract price that exists to-date under the RESOP, FIT and microFIT programs. The monthly embedded generation volumes that flow into the distribution system are determined by dividing the month-end General Ledger account balances for each contract price by the associated contract price. These volumes, including generation exceeding load for net metered customers, are also submitted as part of the Class A and Embedded Generation monthly submission. The IESO adds the distributors' reported embedded generation volumes to the AQEW to calculate the total quantity of supply used to determine dollar amounts to invoice distributors for Global Adjustment.

Alectra Utilities currently has four wholesale market participant ("WMP") customers in the Guelph RZ; three in the General Service 50 kW to 999 kW class; and one in the General Service 1,000-4,999 kW class. A WMP refers to any entity that participates directly in any of the IESO-administered markets. These participants settle commodity and market-related charges (including Global Adjustment) with the IESO even if they are embedded in a distributor's distribution system. As a consequence, consumption volumes related to WMP do not contribute to non-RPP Class B volumes for Accounts 1580, 1588 and 1589 and are not included in these accounts balances.

Guelph RZ does not have any embedded distributors within its service territory and therefore there are no embedded distribution customers on RPP.

RPP Settlement True-Up

Alectra Utilities claims the difference between Regulated Price Plan ("RPP") rates applied to RPP customers, and the sum of the corresponding consumption at the Weighted Average Hourly Spot Price ("WAHSP") and Global Adjustment ("GA") at 2$^{nd}$ estimate GA rate in IESO Form (formerly 1598) each month. The process is completed using General Ledger activity and meter data available from the CIS.

For the current IESO settlement month, Alectra Utilities extracts billed customer RPP commodity charges (TOU and tier pricing) from the General Ledger activity and extracts billed consumption for RPP customers from the CIS system. For IESO settlement purposes, Alectra Utilities' billing system in the Guelph RZ is setup system to determine the WAHSP charges based on corresponding billed consumption for RPP customers. WAHSP and RPP charges are tracked in separate General Ledger accounts. Alectra Utilities adds the estimated GA charges based on the IESO 2$^{nd}$ estimate and WAHSP charges attributed to RPP billed consumption. The amount settled with the IESO is the difference between the billed RPP commodity (TOU and tier pricing) and the sum of the WAHSP and GA charges. Alectra Utilities maintains separate General Ledger accounts to track the RPP settlement and GA settlement portions, which are both tracked in USoA 4705 account.

Each month Alectra Utilities submits a GA true-up to the IESO for the prior month. Beginning in 2018, he Actual GA charges were calculated by applying the corresponding Actual GA rate to the kWh consumption submitted to the IESO for the month, adjusted by unbilled revenue RPP consumption. The monthly true-up is the difference between the Actual GA calculation minus the estimated GA submitted to the IESO based on the 2$^{nd}$ estimate. In the January 2019 RPP settlement submitted in February 2019, Alectra Utilities claimed a GA true-up for December 2018. GA true-ups are captured within USoA 4705. The RPP portion of the IESO Charge Type ("CT") 148 Global Adjustment is reflected in Account 1588 RSVA Power. The non-RPP portion of the CT 148 Global Adjustment is reflected in Account 1589 Global Adjustment.

<u>Internal Controls for RPP Settlement</u>

The Board's Chapter 3 Filing Requirements requires each distributor to provide a description of its internal control tests, if any, in validating estimated and actual consumption figures used in its RPP settlement process and subsequent true-up adjustments.

Alectra Utilities billing system in the Guelph RZ captures the WAHSP charges based on billed consumption for RPP customers. WAHSP and RPP charges are tracked in separate General Ledger accounts. Alectra Utilities adds the estimated GA charges based on the IESO 2$^{nd}$ estimate and RPP billed consumption at the corresponding WAHSP charges. The amount settled with the IESO is the difference between billed RPP commodity (TOU and tier pricing) minus the sum of corresponding WAHSP and GA charges. Alectra Utilities maintains separate General Ledger accounts to track the RPP settlement and GA settlement portions pertaining to RPP customers. During 2018, Alectra Utilities predecessor, Guelph Hydro, submitted all monthly RPP settlement claims to the IESO on or before the fourth business day after calendar month-end. As part of its internal controls, a monthly IESO RPP settlement reconciliation is prepared to ensure that RPP settlement related General Ledger activity is nil at month end. Further, based on a year-end mass rate change on December 31, Alectra Utilities can true-up to actual consumption for the load month of December that is billed in the calendar month of January, for the Guelph RZ. Guelph RZ tracks separately each monthly RPP GA true-up adjustment and can therefore identify the amount of the claim pertaining to the GA true-up for the previous fiscal year.

# Exhibit 3, Tab 1, Schedule 9

# Renewable Generation Connection Rate Protection

## RENEWABLE GENERATION CONNECTION RATE PROTECTION

Alectra Utilities provides a summary of its Renewable Generation Connection Rate Protection ("RGCRP") amounts by rate zone, below.

### Horizon Utilities RZ

In the 2011 Cost of Service Rate Application (EB-2010-0130), the OEB approved Horizon Utilities request for the funding of Renewable Generation Connection Provincial amounts included in its detailed Distribution System Plan ("DSP"), to be recovered through the IESO relating to Renewable Enabling Improvement Investments and Renewable Expansion Investments.

In a letter dated December 20, 2018, Alectra Utiltiies requested that the current IESO renewable generation payments of $707 per month discontinue as of December 31, 2018. Alectra Utilities confirmed in the letter that the Horizon Utilities did incur the expenditures for the renewable generation investments that were approved in Horizon Utilities' 2011 cost of service rate application. Horizon Utilities included 100% of the net book value of the renewable eligible investments in the rate base of Horizon Utilities' 2015 Custom IR application. As a result, the recovery of the IESO provincial payments was over recovered. Therefore, Horizon Utilities recorded the over recovery in Account 1532, Renewable Generation Connection Funding Adder Deferral Account.

In its Decision on 2019 Renewable Connection Rate Protection Compensation Amount (EB-2018-0295), the OEB stated that: *"The OEB will, however, defer its consideration of the return of previous payments received by Guelph Hydro and by Alectra for the Horizon rate zone, to Alectra's application for 2020 distribution rates, including the appropriateness of the methods used by Guelph Hydro and Alectra for returning payments to their own customers that were initially recovered from provincial ratepayers."*

Alectra Utilities is requesting to refund renewable generation funding of $9,726 as a one-time payment in 2020 to the IESO, as identified in Attachment 25.

### Brampton RZ

In the 2015 Cost of Service Rate Application (EB-2014-0083), the Board approved Hydro One Brampton's request for the funding of Renewable Generation Connection Provincial amounts included in its detailed Distribution System Plan ("DSP"), to be recovered through the IESO relating to Renewable Enabling Improvement Investments and Renewable Expansion Investments from 2015 to 2019. Hydro One Brampton's DSP was reviewed by the OEB and its funding requests for eligible investments for 2015 to 2019 were approved by the OEB.

Alectra Utilities is requesting to collect renewable generation funding of $83,483 in 2020 or $6,957 per month from all provincial ratepayers, as identified in Attachment 26 for the Brampton RZ.

**PowerStream RZ**

In the 2016 Custom IR Rate Application (EB-2015-0003), the Board approved PowerStream's request for the funding of Renewable Generation Connection Provincial amounts included in its detailed DSP, to be recovered through the IESO relating to Renewable Enabling Improvement Investments and Renewable Expansion Investments from 2016 to 2020.

The amounts for 2016 and 2017, identified in Table 88 below, were approved in total by the Board in its Decision and Order in respect of the 2017 Green Energy Plan Electricity Rate Protection Benefit and Charge Effective January 1, 2017 (EB-2017-0004), dated February 3, 2017 and its Decision and Order in respect of 2016 Green Energy Plan Electricity Rate Protection Benefit and Charge (EB-2016-0012), dated January 28, 2016. Due to the timing of the 2016 decision, the approved 2015 amount was continued for 2016 and the shortfall was added to the approved amount for 2017. The amount for 2018 was approved by the Board in its Decision and Order in Alectra Utilities' 2018 EDR Application (EB-2017-0024). The amount for 2019 was approved by the Board in its Decision and Order in Alectra Utilities' 2019 EDR Application (EB-2018-0016).

Alectra Utilities is requesting to collect renewable generation funding of $256,814 in 2020 or $21,401 per month from all provincial ratepayers for the PowerStream RZ, as identified in Attachment 27.

**Table 88: Green Energy Plan Rate Protection Benefit and Charge in 2019 – PowerStream RZ**

| | Proposed for Recoveries - TEST YEARS | | | | |
|---|---|---|---|---|---|
| | **2016** | **2017** | **2018** | **2019** | **2020** |
| 2011 & Prior RGC Investmentt | | | | | |
| 2012 RGC Investment | | | | | |
| 2013 RGC Investment | | | | | |
| 2014 RGC Investment | **$150,269** | | | | |
| 2015 RGC Investment | **$4,208** | | | | |
| 2010-2020 RGC Investment | **$272,792** | **$271,060** | **$266,079** | **$260,517** | **$256,894** |
| | **$427,270** | **$271,060** | **$266,079** | **$260,517** | **$256,894** |

## Enersource RZ

Enersource filed a basic Green Energy Plan (the "GEA Plan") which was approved by the Board in Enersource's 2013 cost of service application proceeding (EB-2012-0033). The GEA Plan identified the projects and expenditures associated with the connection of renewable generation to its system and discussed constraints on the ability to connect renewable generation. The GEA Plan was filed in accordance with the *Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence* (EB-2009-0397), which requires distributors to identify the costs related to the connection of FIT and microFIT projects and/or to the implementation of a smart grid. The GEA Plan did not include any smart grid initiatives.

Alectra Utilities is requesting the collection of renewable generation funding for the Enersource RZ of $160,560 or $13,380 per month from all provincial ratepayers, as shown in Attachment 28. Attachment 28 includes actuals up to 2018, and estimates for 2019 and 2020 Renewable Generation Connection funding amounts.

## Guelph Hydro RZ

In the 2012 Cost of Service Rate Application (EB-2011-0123), the OEB approved Guelph Hydro's request for the funding of Renewable Generation Connection Provincial amounts included in its detailed Distribution System Plan ("DSP"), to be recovered through the IESO relating to Renewable Enabling Improvement Investments and Renewable Expansion Investments.

In a letter dated November 29, 2018, Alectra Utiltiies requested to discontinue the collection of provincial funding for the eligible investments that were approved in its 2012 cost of service decision. In addition, Guelph Hydro proposed returning to the IESO the provincial payments in the total amount of $208,512 received in 2015, 2017 and 2018. Guelph Hydro stated that it had received a total of $350,844 from 2013 to 2018 regarding the provincial funding for the eligible investments that were approved in its 2012 cost of service decision. Guelph Hydro stated that it had not incurred any capital costs for these investments since all costs were offset by customers' capital contributions. As a result, Guelph Hydro was not entitled to any RGCRP payments from the IESO for the subject investments.

In its Decision on 2019 Renewable Connection Rate Protection Compensation Amount (EB-2018-0295), the OEB stated that: *"The OEB will, however, defer its consideration of the return of previous payments received by Guelph Hydro and by Alectra for the Horizon rate zone, to Alectra's application for 2020 distribution rates, including the appropriateness of the methods used by Guelph Hydro and Alectra for returning payments to their own customers that were initially recovered from provincial ratepayers."*

Alectra Utilities is requesting to refund renewable generation funding of $208,512 as a one-time payment in 2020 to the IESO, as identified in Attachment 29.

# Exhibit 3, Tab 1, Schedule 10

# Disposition of LRAM Variance Account

## DISPOSITION OF LRAM VARIANCE ACCOUNT

Alectra Utilities is applying for disposition of the balance in its the LRAM variance account ("LRAMVA") resulting from its Conservation and Demand Management ("CDM") activities in 2017 in the Horizon Utilities, Brampton, PowerStream and Enersource RZs. Alectra Utilities' predecessor, Guelph Hydro, requested disposition of its 2017 LRAMVA balance in its 2019 EDR Application (EB-2018-0036). In that proceeding, the Board approved Guelph Hydro's request to recover lost revenues from CDM activities in 2017, in the amount of $620,646. Therefore, no further relief is being sought in this Application with respect to Guelph Hydro's 2017 LRAMVA balances.

### Lost Revenue Adjustment Mechanism for 2011-2014 and 2015-2020

On March 31, 2010, the Ministry of Energy and Infrastructure issued a directive to the OEB (the "Directive") to establish electricity and conservation and demand management targets to be met by licensed electricity distributors over a four year period commencing January 1, 2011. The Minister of Energy and Infrastructure included guidance to the OEB that lost revenues that result from CDM programs should not act as a disincentive to a distributor to promote CDM activities.

On April 26, 2012, in response to the Directive, the OEB issued a new set of *Guidelines for Electricity Distributor Conservation and Demand Management* (EB-2012-0003) ("2012 CDM Guidelines") which set out the obligations and requirements with which electricity distributors must comply in relation to the CDM targets that are a condition of licence. The 2012 CDM Guidelines also provided updated details for the Lost Revenue Adjustment Mechanism ("LRAM") to compensate distributors for lost revenues resulting from CDM programs for the 2011 to 2014 period.

The OEB authorized the establishment of an LRAMVA to record, at the customer rate-class level, the difference between:

(i) the results of actual, verified impacts of authorized CDM activities undertaken by electricity distributors between 2011-2014 for CDM programs, and

(ii) the level of CDM program activities included in the distributor's load forecast (i.e. the level embedded into rates).

The variance calculated from the comparison will result in a credit or a debit to the ratepayer at the customer class level in the LRAMVA.

On March 31, 2014, the Ministry of Energy and Infrastructure, in response to the Government of Ontario's Long-Term Energy Plan ("LTEP"), issued a directive to the OEB ("the Conservation Directive") to promote CDM, including amending the licences of electricity distributors and establishing CDM Requirement guidelines (the "2015 CDM Guidelines").

On December 19, 2014, the OEB issued *Conservation and Demand Management Requirement Guidelines for Electricity Distributors* (EB-2014-0278) ("2015 CDM Guidelines") which amended the electricity distribution licences of all electricity distributors to include a condition that requires the distributors to make CDM programs available to each customer segment in their service area and to report annual CDM results to the IESO. The Board also requires that electricity distributors work with natural gas distributors and the IESO in coordinating and integrating electricity conservation and natural gas demand side management programs. The 2015 CDM Guidelines also confirmed the continuation of the LRAM mechanism to compensate distributors for lost revenues resulting from CDM programs for the 2015 to 2020 period.

On May 19, 2016, the OEB issued an *Updated Policy for the Lost Revenue Adjustment Mechanism Calculation: Lost Revenues and Peak Demand Savings from Conservation and Demand Management Programs,* on the calculation of the LRAMVA in respect of peak demand savings. In this report, the OEB determined that distributors should multiply the peak demand (kW) savings amounts from energy efficiency programs included in the IESO Final Results by the number of months the IESO has indicated those savings take place throughout the year. The OEB also indicated that peak demand savings from Demand Response ("DR") programs should generally not be included within the LRAMVA calculation.

**LRAM Calculations**

The OEB has identified that distributors can apply for disposition of the balance in the LRAMVA as part of their cost of service applications and may apply for disposition on an annual basis, as part of their IRM application, if the balance is deemed significant by the applicant. Alectra Utilities is requesting approval for the recovery of lost revenues of $7,257,929 across the Horizon Utilities, Brampton, PowerStream and Enersource RZs, which is above the materiality threshold for Alectra

Utilities. The materiality threshold, as defined by the OEB, is $1 million for a distributor with a distribution revenue requirement of more than $200 million.

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 2019 LRAMVA work form provided by the OEB to calculate the variance between actual CDM savings and forecast CDM savings. The LRAMVA work form is filed as a working Microsoft Excel file as directed by the Board in the Chapter 3 Filing Requirements issued by the OEB on July 12, 2018, and is provided in Attachments 30 to 33. Alectra Utilities has not included peak demand (kW) savings from Demand Response programs in its lost revenue calculation in accordance with Board's 2016 Updated Policy on the calculation of peak demand savings.

In accordance with the Chapter 3 Filing Requirements, Alectra Utilities provides the following information:

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

(ii) Alectra Utilities has relied on the most recent and appropriate final CDM evaluation report from the IESO in support of the lost revenue calculation. The IESO's Final Annual Verified Results for 2017 is filed as Attachment 34.

(iii) The IESO reports results by program. These only partially map onto rate classes. For initiatives that apply to more than one rate class, Alectra Utilities estimated the allocation by rate class, drawing on participant-specific information where available; and

(iv) Alectra Utilities has provided additional data in Tab 8. Street Lighting of the LRAMVA Model, where applicable, in support of the Street Lighting project savings. Demand savings for the retrofit streetlight project do not appear on the IESO's Final Verified Result Report, as the reduction to peak demand occurs outside the IESO's peak hours. Demand savings were calculated based on the difference between billed kW demand from Alectra Utilities' billing system on the streetlight account compared to the billed kW demand based on the pre-completion of the LED street lights project.

At the time of this filing, the IESO has not issued the Final Annual Verified Results for 2018. Alectra Utilities proposes to dispose of its 2018 LRAMVA balance in a future rate proceeding. Alectra Utilities identifies that the balance in Account 1568, LRAMVA, as identified in Tab "3. Continuity Schedule" does not match the amount being requested for disposition due to the exclusion of the 2018 balances as mentioned previously.

Alectra Utilities provides a summary of relief sought by rate zone, below.

**<u>Horizon Utilities RZ</u>**

Alectra Utilities is seeking recovery of lost revenues for the period January 1, 2017 to December 31, 2017 resulting from the following:

(i) 2015 and 2016 CDM persistence savings in 2017; and

(ii) Incremental savings from IESO-funded CDM programs implemented in 2017.

The total amount requested for disposition in the Horizon Utilities RZ is a debit of $1,312,925 including forecasted carrying charges of $58,907 through to December 31, 2019. Actual savings from CDM activities for 2017 was above the estimated projections used in the load forecast resulting in an under-collection from customers during this period. Alectra Utilities' most recent application for the recovery of lost revenues due to CDM activities was filed in Alectra Utilities 2019 EDR Application (EB-2018-0016). In that proceeding, the Board approved Alectra Utilities' request to recover lost revenues from CDM activities in 2016 in the Horizon Utilities RZ.

In calculating the lost revenue amounts by rate class, CDM verified savings (in kWh and kW) were multiplied by the appropriate Board-approved variable distribution rates for the respective period as provided in Tab "3. Distribution Rates" of the LRAMVA work form and in Table 89 identified below.

**Table 89 – Distribution Volumetric Rates – Horizon Utilities RZ**

| Year | Residential | GS<50 kW | General Service 50 to 4,999 kW | Large Use (1) | Large Use (2) | Street Lighting | Unmetered Scattered Load |
|---|---|---|---|---|---|---|---|
| | kWh | kWh | kW | kW | kWh | kW | kW |
| 2017 | $0.0084 | $0.0107 | $2.5533 | $1.4051 | $0.3334 | $5.6585 | $0.0121 |

Horizon Utilities' LRAMVA threshold approved in its 2015 Custom IR Application (EB-2014-0002) is used as the comparator against actual savings for the lost revenue calculation for 2017. The LRAMVA thresholds are provided in Tab "2. LRAMVA Threshold" of the LRAMVA work form and in Table 90 identified below.

**Table 90 – LRAMVA Thresholds – Horizon Utilities RZ**

| Year | LRAMVA Threshold | Residential | GS<50 KW | General Service 50 To 4,999 KW |
|---|---|---|---|---|
| | | kWh | kWh | kW |
| 2017 | 2017 | 3,027,867 | 846,487 | 34,728 |

Alectra Utilities has calculated carrying charges on the LRAM amounts from January 1, 2017 to December 31, 2019 in the LRAMVA work form using the OEB's annual prescribed interest rates as provided in Tab "6. Carrying Charges" of the LRAMVA work form. The total amount requested for disposition is a recovery of $1,312,925, representing a principal balance of $1,254,018 and carrying charges of $58,907.

Alectra Utilities has provided a summary of its lost revenue calculations by year for each rate class in Tables 91 and 93 below for, which is also provided in Tab "1. LRAMVA Summary" of the LRAMVA work form.

**Table 91 – LRAMVA Totals by Rate Class – Horizon Utilities RZ**

| Customer Class | Billing Unit | Principle ($) | Carrying Charges ($) | Total LRAMVA ($) |
|---|---|---|---|---|
| Residential | kWh | $621,758 | $29,207 | $650,965 |
| GS<50 kW | kWh | $363,423 | $17,072 | $380,495 |
| General Service 50 To 4,999 KW | kW | $60,893 | $2,860 | $63,753 |
| Large Use (1) | kW | $10,447 | $491 | $10,938 |
| Large Use (2) | kW | $17,507 | $822 | $18,329 |
| Street Lighting | kW | $155,454 | $7,302 | $162,756 |
| Unmetered Scattered Load | kWh | $24,535 | $1,153 | $25,688 |
| **Total** | | **$1,254,018** | **$58,907** | **$1,312,925** |

**Table 92 – LRAMVA by Year and Rate Class – Horizon Utilities RZ**

| Description | Residential | GS<50 kW | General Service 50 To 4,999 KW | Large Use (1) | Large Use (2) | Street Lighting | Unmetered Scattered Load | Total |
|---|---|---|---|---|---|---|---|---|
| | kWh | kWh | kW | kW | kW | kW | kWh | |
| 2017 Actuals | $647,293 | $372,480 | $149,564 | $10,447 | $17,507 | $155,454 | $24,535 | $1,377,281 |
| 2017 Forecast | ($25,535) | ($9,057) | ($88,671) | $0 | $0 | $0 | $0 | ($123,263) |
| **2017 LRAM Balance** | $621,758 | $363,423 | $60,893 | $10,447 | $17,507 | $155,454 | $24,535 | **$1,254,018** |
| | | | | | | | | |
| **Carrying Charges** | **$29,207** | **$17,072** | **$2,860** | **$491** | **$822** | **$7,302** | **$1,153** | **$58,907** |
| | | | | | | | | |
| **Total LRAMVA Balance** | **$650,965** | **$380,495** | **$63,753** | **$10,938** | **$18,329** | **$162,756** | **$25,688** | **$1,312,925** |

The proposed rate riders that result from the disposition of Account 1568, LRAMVA, are identified in Table 93 below and included in Tab "8. Calculation of Def-Var RR" in the IRM Model.

**Table 93 – LRAMVA Rate Riders – Horizon Utilities RZ**

| Rate Class | Volumetric Rate Rider | Per |
|---|---|---|
| Residential | $0.0004 | kWh |
| General Service Less Than 50 Kw | $0.0007 | kWh |
| General Service 50 To 4,999 Kw | $0.0134 | kW |
| Large Use (1) | $0.0304 | kW |
| Large Use (2) | $0.0092 | kW |
| Unmetered Scattered Load | $0.0023 | kWh |
| Sentinel Lighting | $0.0000 | kW |
| Street Lighting | $2.7694 | kW |

**<u>Brampton RZ</u>**

Alectra Utilities is seeking recovery of lost revenues for the period January 1, 2017 to December 31, 2017 resulting from the following:

(i) 2013 to 2016 CDM persistence savings in 2017; and

(ii) Incremental savings from IESO-funded CDM programs implemented in 2017.

Alectra Utilities is applying for disposition of the balance in the LRAM variance account ("LRAMVA") resulting from its Conservation and Demand Management ("CDM") activities in 2017 in the Brampton RZ. The total amount requested for disposition is a debit of $1,095,288 including forecasted carrying charges of $49,143 through to December 31, 2019. Actual savings from CDM activities for 2017 was above the estimated projections used in the load forecast resulting in an under-collection from customers during this period. Alectra Utilities' most recent application for the recovery of lost revenues due to CDM activities was filed in Alectra Utilities 2019 EDR Application (EB-2018-0016). In that proceeding, the Board approved Alectra Utilities' request to recover lost revenues from CDM activities in 2016 in the Brampton RZ.

In calculating the lost revenue amounts by rate class, CDM verified savings (in kWh and kW) were multiplied by the appropriate Board-approved variable distribution rates for the respective period as provided in Tab "3. Distribution Rates" of the LRAMVA work form and in Table 94 identified below.

**Table 94 – Distribution Volumetric Rates – Brampton RZ**

| Year | Residential | GS<50 kW | General Service 50 To 699 Kw | General Service 700 To 4,999 Kw | Large Use |
|---|---|---|---|---|---|
| | kWh | kWh | kW | kW | kW |
| 2017 | $0.0080 | $0.0167 | $2.8387 | $3.2953 | $2.4949 |

Brampton Hydro's LRAMVA threshold approved in its 2015 Cost of Service Application (EB-2014-0083) is used as the comparator against actual savings for the lost revenue calculation for 2017. The LRAMVA thresholds are provided in Tab "2. LRAMVA Threshold" of the LRAMVA work form and in Table 95 identified below.

**Table 95 – LRAMVA Thresholds – Brampton RZ**

| Year | LRAMVA Threshold | Residential | GS<50 KW | General Service 50 To 699 KW | General Service 700 To 4,999 KW |
|---|---|---|---|---|---|
| | | kWh | kWh | kW | kW |
| 2017 | 2015 | 12,486,005 | 1,448,724 | 64,526 | 35,242 |

Alectra Utilities has calculated carrying charges on the LRAM amounts from January 1, 2017 to December 31, 2019 in the LRAMVA work form using the OEB's annual prescribed interest rates as provided in Tab "6. Carrying Charges" of the LRAMVA work form. The total amount requested for disposition is a recovery of $1,095,288, representing a principal balance of $1,046,145 and carrying charges of $49,143.

Alectra Utilities has provided a summary of its lost revenue calculations by year for each rate class in Tables 96 and 98 below for, which is also provided in Tab "1. LRAMVA Summary" of the LRAMVA work form.

**Table 96 – LRAMVA Totals by Rate Class – Brampton RZ**

| Customer Class | Billing Unit | Principle ($) | Carrying Charges ($) | Total LRAMVA ($) |
|---|---|---|---|---|
| Residential | kWh | $460,859 | $21,649 | $482,508 |
| GS<50 kW | kWh | $307,211 | $14,431 | $321,642 |
| General Service 50 To 699 KW | kW | $155,236 | $7,292 | $162,528 |
| General Service 700 To 4,999 KW | kW | $86,114 | $4,045 | $90,159 |
| Large Use | kW | $36,725 | $1,725 | $38,451 |
| **Total** | | **$1,046,145** | **$49,143** | **$1,095,288** |

**Table 97 – LRAMVA by Year and Rate Class – Brampton RZ**

| Description | Residential | GS<50 kW | General Service 50 To 699 KW | General Service 700 To 4,999 KW | Large Use | Total |
|---|---|---|---|---|---|---|
| | kWh | kWh | kW | kW | kW | |
| 2017 Actuals | $560,747 | $331,404 | $338,405 | $202,247 | $36,725 | $1,469,529 |
| 2017 Forecast | ($99,888) | ($24,194) | ($183,169) | ($116,133) | $0 | ($423,384) |
| **2017 LRAM Balance** | **$460,859** | **$307,211** | **$155,236** | **$86,114** | **$36,725** | **$1,046,145** |
| | | | | | | |
| **Carrying Charges** | **$21,649** | **$14,431** | **$7,292** | **$4,045** | **$1,725** | **$49,143** |
| | | | | | | |
| **Total LRAMVA Balance** | **$482,508** | **$321,642** | **$162,528** | **$90,159** | **$38,451** | **$1,095,288** |

The proposed rate riders that result from the disposition of Account 1568, LRAMVA, are identified in Table 98 below and included in Tab "8. Calculation of Def-Var RR" in the IRM Model.

**Table 98 – LRAMVA Rate Riders – Brampton RZ**

| Rate Class | Volumetric Rate Rider | Per |
|---|---|---|
| Residential | $0.0003 | kWh |
| GS<50 kW | $0.0009 | kWh |
| General Service 50 To 699 KW | $0.0511 | kW |
| General Service 700 To 4,999 KW | $0.0446 | kW |
| Large Use | $0.0584 | kW |

**PowerStream RZ**

Alectra Utilities is seeking recovery of lost revenues for the period January 1, 2017 to December 31, 2017 resulting from the following:

(i) 2015 and 2016 CDM persistence savings in 2017; and

(ii) Incremental savings from IESO-funded CDM programs implemented in 2017.

Alectra Utilities is applying for disposition of the balance in the LRAM variance account ("LRAMVA") resulting from its Conservation and Demand Management ("CDM") activities in 2017 in the PowerStream RZ. The total amount requested for disposition is a debit of $2,460,286 including forecasted carrying charges of $110,346 through to December 31, 2019. Actual savings from CDM activities for 2017 was above the estimated projections used in the load forecast resulting in an under-collection from customers during this period. Alectra Utilities' most recent application for the recovery of lost revenues due to CDM activities was filed in Alectra Utilities 2019 EDR Application (EB-2018-0016). In that proceeding, the Board approved Alectra Utilities' request to recover lost revenues from CDM activities in 2016 in the PowerStream RZ.

In calculating the lost revenue amounts by rate class, CDM verified savings (in kWh and kW) were multiplied by the appropriate Board-approved variable distribution rates for the respective period as provided in Tab "3. Distribution Rates" of the LRAMVA work form and in Table 99 identified below.

**Table 99 – Distribution Volumetric Rates – PowerStream RZ**

| Year | Residential | GS<50 kW | GS>50 kW | Large Use | Unmetered Scattered Load | Sentinel Lighting | Street Lighting |
|---|---|---|---|---|---|---|---|
| | kWh | kWh | kW | kW | kWh | kW | kW |
| 2017 | $0.0130 | $0.0183 | $4.2037 | $2.2421 | $0.0195 | $9.8694 | $6.3222 |

PowerStream's LRAMVA threshold approved in its 2017 Custom of Service Application (EB-2015-0003) is used as the comparator against actual savings for the lost revenue calculation for 2017. The LRAMVA thresholds are provided in Tab "2. LRAMVA Threshold" of the LRAMVA work form and in Table 100 identified below.

**Table 100 – LRAMVA Thresholds – PowerStream RZ**

| Year | LRAMVA Threshold | Residential | GS<50 KW | GS>50 KW |
|---|---|---|---|---|
| | | kWh | kWh | kW |
| 2017 | 2017 | 48,703,932 | 32,279,911 | 321,969 |

Alectra Utilities has calculated carrying charges on the LRAM amounts from January 1, 2017 to December 31, 2019 in the LRAMVA work form using the OEB's annual prescribed interest rates as provided in Tab "6. Carrying Charges" of the LRAMVA work form. The total amount requested for disposition is a recovery of $2,460,286, representing a principal balance of $2,349,939 and carrying charges of $110,346.

Alectra Utilities has provided a summary of its lost revenue calculations by year for each rate class in Tables 101 and 103 below for, which is also provided in Tab "1. LRAMVA Summary" of the LRAMVA work form.

**Table 101 – LRAMVA Totals by Rate Class – PowerStream RZ**

| Customer Class | Billing Unit | Principle ($) | Carrying Charges ($) | Total LRAMVA ($) |
|---|---|---|---|---|
| Residential | kWh | $1,559,147 | $73,241 | $1,632,388 |
| GS<50 KW | kWh | $82,985 | $3,898 | $86,884 |
| GS>50 KW | kW | $483,676 | $22,721 | $506,397 |
| Large Use | kW | $3,468 | $163 | $3,631 |
| Unmetered Scattered Load | kWh | $0 | $0 | $0 |
| Sentinel Lighting | kW | $0 | $0 | $0 |
| Street Lighting | kW | $220,663 | $10,324 | $230,986 |
| **Total** | | **$2,349,939** | **$110,346** | **$2,460,286** |

**Table 102 – LRAMVA by Year and Rate Class – PowerStream RZ**

| Description | Residential | GS<50 kW | GS>50 KW | Large Use | Street Lighting | Total |
|---|---|---|---|---|---|---|
| | kWh | kWh | kW | kW | kW | |
| 2017 Actuals | $2,192,298 | $673,708 | $1,837,137 | $3,468 | $220,663 | $4,927,274 |
| 2017 Forecast | ($633,151) | ($590,722) | ($1,353,461) | $0 | $0 | ($2,577,335) |
| **2017 LRAM Balance** | $1,559,147 | $82,985 | $483,676 | $3,468 | $220,663 | **$2,349,939** |
| | | | | | | |
| **Carrying Charges** | **$73,241** | **$3,898** | **$22,721** | **$163** | **$10,324** | **$110,346** |
| | | | | | | |
| **Total LRAMVA Balance** | **$1,632,388** | **$86,884** | **$506,397** | **$3,631** | **$230,986** | **$2,460,286** |

The proposed rate riders that result from the disposition of Account 1568, LRAMVA, are identified in Table 103 below and included in Tab "8. Calculation of Def-Var RR" in the IRM Model.

**Table 103 – LRAMVA Rate Riders – PowerStream RZ**

| Rate Class | Volumetric Rate Rider | Per |
|---|---|---|
| Residential Service Classification | $0.0006 | kWh |
| General Service Less Than 50 Kw Service Classification | $0.0001 | kWh |
| General Service 50 To 4,999 Kw Service Classification | $0.0415 | kW |
| Large Use Service Classification | $0.0353 | kW |
| Unmetered Scattered Load Service Classification | $0.0000 | kWh |
| Standby Power Service Classification | $0.0000 | kW |
| Sentinel Lighting Service Classification | $0.0000 | kW |
| Street Lighting Service Classification | $1.7218 | kW |

**Enersource RZ**

Alectra Utilities is seeking recovery of lost revenues for the period January 1, 2017 to December 31, 2017 resulting from the following:

(i) 2011 to 2016 CDM persistence savings in 2017; and

(ii) Incremental savings from IESO-funded CDM programs implemented in 2017.

Alectra Utilities is applying for disposition of the balance in the LRAM variance account ("LRAMVA") resulting from its Conservation and Demand Management ("CDM") activities in 2017 in the Enersource RZ. The total amount requested for disposition is a debit of $2,389,285 including forecasted carrying charges of $107,201 through to December 31, 2019. Actual savings from CDM activities for 2017 was above the estimated projections used in the load forecast resulting in an under-collection from customers during this period. Alectra Utilities' most recent application for the recovery of lost revenues due to CDM activities was filed in Alectra Utilities 2019 EDR Application (EB-2018-0016). In that proceeding, the Board approved Alectra Utilities' request to recover lost revenues from CDM activities in 2016 in the Enersource RZ.

In calculating the lost revenue amounts by rate class, CDM verified savings (in kWh and kW) were multiplied by the appropriate Board-approved variable distribution rates for the respective period as provided in Tab "3. Distribution Rates" of the LRAMVA work form and in Table 104 identified below.

**Table 104 – Distribution Volumetric Rates – Enersource RZ**

| Year | Residential | GS<50 kW | General Service 50 to 499 kW | General Service 500 to 4,999 kW | Large Use | Street Lighting |
|---|---|---|---|---|---|---|
| | kWh | kWh | kW | kW | kW | kW |
| 2017 | $0.0069 | $0.0127 | $4.6213 | $2.3780 | $2.9516 | $11.5465 |

Enersource's LRAMVA threshold approved in its 2013 Custom of Service Application (EB-2012-0033) is used as the comparator against actual savings for the lost revenue calculation for 2017. The LRAMVA thresholds are provided in Tab "2. LRAMVA Threshold" of the LRAMVA work form and in Table 105 identified below.

**Table 105 – LRAMVA Thresholds – Enersource RZ**

| Year | LRAMVA Threshold | Residential | GS<50 KW | General Service 50 To 499 KW | General Service 500 To 4,999 KW | Large Use | Street Lighting |
|---|---|---|---|---|---|---|---|
| | | kWh | kWh | kW | kW | kW | kW |
| 2017 | 2013 | 35,842,920 | 39,519,293 | 19,284 | 16,135 | 15,417 | 61,001 |

Alectra Utilities has calculated carrying charges on the LRAM amounts from January 1, 2017 to December 31, 2019 in the LRAMVA work form using the OEB's annual prescribed interest rates as provided in Tab "6. Carrying Charges" of the LRAMVA work form. The total amount requested for disposition is a recovery of $2,389,285, representing a principal balance of $2,282,084 and carrying charges of $107,201.

Alectra Utilities has provided a summary of its lost revenue calculations by year for each rate class in Tables 106 and 108 below for, which is also provided in Tab "1. LRAMVA Summary" of the LRAMVA work form.

**Table 106 – LRAMVA Totals by Rate Class – Enersource RZ**

| Customer Class | Billing Unit | Principle ($) | Carrying Charges ($) | Total LRAMVA ($) |
|---|---|---|---|---|
| Residential | kWh | $464,179 | $21,805 | $485,984 |
| GS<50 kW | kWh | $38,351 | $1,802 | $40,153 |
| General Service 50 To 499 KW | kW | $1,297,570 | $60,953 | $1,358,524 |
| General Service 500 To 4,999 KW | kW | $452,457 | $21,254 | $473,711 |
| Large Use | kW | $155,811 | $7,319 | $163,130 |
| Street Lighting | kW | ($126,284) | ($5,932) | ($132,216) |
| **Total** | | **$2,282,084** | **$107,201** | **$2,389,285** |

**Table 107 – LRAMVA by Year and Rate Class – Enersource RZ**

| Description | Residential | GS<50 kW | General Service 50 To 499 KW | General Service 500 to 4,999 kW | Large Use | Street Lighting | Total |
|---|---|---|---|---|---|---|---|
| | kWh | kWh | kW | kW | kW | kW | |
| 2017 Actuals | $711,495 | $540,246 | $1,386,687 | $490,826 | $201,316 | $578,064 | **$3,908,634** |
| 2017 Forecast | ($247,316) | ($501,895) | ($89,117) | ($38,369) | ($45,505) | ($704,348) | **($1,626,550)** |
| **2017 LRAM Balance** | $464,179 | $38,351 | $1,297,570 | $452,457 | $155,811 | ($126,284) | **$2,282,084** |
| | | | | | | | |
| **Carrying Charges** | **$21,805** | **$1,802** | **$60,953** | **$21,254** | **$7,319** | **($5,932)** | **$107,201** |
| | | | | | | | |
| **Total LRAMVA Balance** | **$485,984** | **$40,153** | **$1,358,524** | **$473,711** | **$163,130** | **($132,216)** | **$2,389,285** |

The proposed rate riders that result from the disposition of Account 1568, LRAMVA, are identified in Table 108 below and included in Tab "8. Calculation of Def-Var RR" in the IRM Model.

## Table 108 – LRAMVA Rate Riders – Enersource RZ

| Rate Class | Volumetric Rate Rider | Per |
|---|---|---|
| Residential Service Classification | $0.0003 | kWh |
| General Service Less Than 50 kW Service Classification | $0.0001 | kWh |
| General Service 50 To 499 kW Service Classification | $0.2379 | kW |
| General Service 500 To 4,999 kW Service Classification | $0.1033 | kW |
| Large Use Service Classification | $0.0930 | kW |
| Street Lighting Service Classification | ($3.2588) | kW |

# Exhibit 3, Tab 1, Schedule 11

## Tax Changes

**TAX CHANGES**

The OEB policy, as described in the Board's 2008 Report entitled *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "Supplemental Report"), prescribes a 50/50 sharing of impacts of legislated tax changes from distributors' tax rates embedded in their OEB approved base rates. If applicable, these amounts will be refunded to customers over a 12-month period.

The Government of Canada introduced Bill C-97, *Budget Implementation Act, 2019, No 1*, on April 8 to implement measures announced in the 2019 federal budget. As part of Bill C-97, the federal government proposes to introduce an Accelerated Investment Incentive ("AII") to support all businesses that make capital investments. Under the AII, capital investments will generally be eligible for a first-year deduction for depreciation equal to up to three times the amount that would otherwise apply in the year an asset is put into use, thereby allowing businesses to recover the initial cost of their investment more quickly. The AII will apply to all tangible capital assets, including long-lived investments like buildings, acquired after November 20, 2018. The AII will gradually be phased out starting in 2024 and will no longer be in effect for investments put in use after 2027.

The first reading of the bill took place on April 8, 2019. The second reading and referral to the Standing Committee on Finance took place on April 30, 2019; the bill passed the second reading. Alectra Utilities will continue to monitor further developments and review any guidance published by the OEB on this matter.

## Exhibit 3, Tab 1, Schedule 12

## Summary of Bill Impacts

## SUMMARY OF BILL IMPACTS

A summary of bill impacts for the typical customer by rate class is presented in Tables 109 to 118 below. Tab 21 Bill Impacts, of the IRM Model filed as Attachments 12 to 16 provides the detailed bill impacts for each customer class for 2020.

**Table 109 – Distribution Bill Impacts by Rate Class – Horizon Utilities RZ**

| Distribution Bill Impacts | | | | |
|---|---|---|---|---|
| **Customer Class** | **Billing Units** | **Average Monthly Volume** | **2020 vs. 2019** | |
| | | | **$** | **%** |
| Residential | kWh | 750 | $ 0.56 | 2.1% |
| GS<50 | kWh | 2,000 | $ 1.30 | 2.0% |
| GS>50 | kW | 250 | $ 21.12 | 2.0% |
| Large User | kW | 5,000 | $ 618.60 | 2.0% |
| Large User with Dedicated Asset | kW | 20,000 | $ 278.84 | 2.2% |
| Street Lighting | kW | 4,974 | $ 6,342.92 | 18.8% |

Table excludes the impact of HST (13%) & Provincial Rebate (8%)

**Table 110 – Total Bill Impacts by Rate Class (before HST) – Horizon Utilities RZ**

| Total Bill Impacts | | | | |
|---|---|---|---|---|
| **Customer Class** | **Billing Units** | **Average Monthly Volume** | **2020 vs. 2019** | |
| | | | **$** | **%** |
| Residential | kWh | 750 | $ 2.33 | 2.2% |
| GS<50 | kWh | 2,000 | $ 5.59 | 2.1% |
| GS>50 | kW | 250 | $ 287.22 | 1.9% |
| Large User | kW | 5,000 | $ 7,367.60 | 2.1% |
| Large User with Dedicated Asset | kW | 20,000 | $ 20,018.84 | 1.5% |
| Street Lighting | kW | 4,974 | $ 11,072.64 | 4.2% |

Table excludes the impact of HST (13%) & Provincial Rebate (8%)

**Table 111 – Distribution Bill Impacts by Rate Class – Brampton RZ**

| Distribution Bill Impacts | | | | |
|---|---|---|---|---|
| Customer Class | Billing Units | Average Monthly Volume | 2020 vs. 2019 | |
| | | | $ | % |
| Residential | kWh | 750 | $ 0.91 | 3.7% |
| GS<50 | kWh | 2,000 | $ 1.92 | 3.1% |
| GS>50 to 699 | kW | 500 | $ 48.67 | 3.0% |
| GS 700 to 4,999 | kW | 1,432 | $ 242.49 | 4.0% |
| Large User | kW | 20,000 | $ 2,115.83 | 3.7% |
| Street Lighting | kW | 7,922 | $ 3,683.02 | 3.9% |

Table excludes the impact of HST (13%) & Provincial Rebate (8%)

**Table 112 – Total Bill Impacts by Rate Class (before HST) – Brampton RZ**

| Total Bill Impacts | | | | |
|---|---|---|---|---|
| Customer Class | Billing Units | Average Monthly Volume | 2020 vs. 2019 | |
| | | | $ | % |
| Residential | kWh | 750 | $ 2.27 | 2.2% |
| GS<50 | kWh | 2,000 | $ 5.14 | 2.0% |
| GS>50 to 699 | kW | 500 | $ 10.72 | 0.0% |
| GS 700 to 4,999 | kW | 1,432 | $ 87.40 | 0.1% |
| Large User | kW | 20,000 | $ 19,355.83 | 1.4% |
| Street Lighting | kW | 7,922 | $ 4,484.49 | 1.0% |

Table excludes the impact of HST (13%) & Provincial Rebate (8%)

**Table 113 – Distribution Bill Impacts by Rate Class – PowerStream RZ**

| Distribution Bill Impacts | | | | |
|---|---|---|---|---|
| Customer Class | Billing Units | Average Monthly Volume | 2020 vs. 2019 | |
| | | | $ | % |
| Residential | kWh | 750 | $ 0.81 | 2.8% |
| GS<50 | kWh | 2,000 | $ 0.90 | 1.3% |
| GS>50 | kW | 250 | $ 23.43 | 1.9% |
| Large User | kW | 7,350 | $ 1,584.22 | 7.0% |
| Street Lighting | kW | 1 | $ 0.62 | 6.8% |

Table excludes the impact of HST (13%) & Provincial Rebate (8%)

**Table 114 – Total Bill Impacts by Rate Class (before HST) – PowerStream RZ**

| Total Bill Impacts | | | | |
|---|---|---|---|---|
| Customer Class | Billing Units | Average Monthly Volume | 2020 vs. 2019 | |
| | | | $ | % |
| Residential | kWh | 750 | $ 2.10 | 2.0% |
| GS<50 | kWh | 2,000 | $ 4.33 | 1.6% |
| GS>50 | kW | 250 | $ (365.63) | (3.0)% |
| Large User | kW | 7,350 | $ 9,825.77 | 2.6% |
| Street Lighting | kW | 1 | $ 0.51 | 1.1% |

Table excludes the impact of HST (13%) & Provincial Rebate (8%)

**Table 115 – Distribution Bill Impacts by Rate Class – Enersource RZ**

| Distribution Bill Impacts | | | | |
|---|---|---|---|---|
| Customer Class | Billing Units | Average Monthly Volume | 2020 vs. 2019 | |
| | | | $ | % |
| Residential | kWh | 750 | $ 0.58 | 2.3% |
| GS<50 | kWh | 2,000 | $ 1.27 | 1.7% |
| GS>50 to 499 | kW | 230 | $ 21.03 | 1.7% |
| GS>500 to 4,999 | kW | 2,250 | $ 162.34 | 2.1% |
| Large User | kW | 5,000 | $ 569.98 | 1.9% |
| Street Lighting | kW | 0.10 | $ 0.16 | 6.7% |

Table excludes the impact of HST (13%) & Provincial Rebate (8%)

**Table 116 – Total Bill Impacts by Rate Class (before HST) – Enersource RZ**

| Total Bill Impacts | | | | |
|---|---|---|---|---|
| Customer Class | Billing Units | Average Monthly Volume | 2020 vs. 2019 | |
| | | | $ | % |
| Residential | kWh | 750 | $ 1.55 | 1.5% |
| GS<50 | kWh | 2,000 | $ 3.87 | 1.4% |
| GS>50 to 499 | kW | 230 | $ (375.51) | (2.6)% |
| GS>500 to 4,999 | kW | 2,250 | $ 1,386.56 | 2.1% |
| Large User | kW | 5,000 | $ 4,019.48 | 1.0% |
| Street Lighting | kW | 0.10 | $ 0.03 | 0.5% |

Table excludes the impact of HST (13%) & Provincial Rebate (8%)

**Table 117 – Distribution Bill Impacts by Rate Class – Guelph Hydro RZ**

| Distribution Bill Impacts | | | | |
|---|---|---|---|---|
| **Customer Class** | **Billing Units** | **Average Monthly Volume** | **2020 vs. 2019** | |
| | | | **$** | **%** |
| Residential | kWh | 750 | $ 0.11 | 0.4% |
| GS<50 | kWh | 2,000 | $ (0.16) | (0.4)% |
| GS>50 to 999 | kW | 500 | $ (14.01) | (0.9)% |
| GS 1000 to 4,999 | kW | 1,000 | $ (20.83) | (0.6)% |
| Large User | kW | 7,500 | $ (5,112.05) | (18.7)% |
| Street Lighting | kW | 2,200 | $ 1,906.97 | 8.9% |

Table excludes the impact of HST (13%) & Provincial Rebate (8%)

**Table 118 – Total Bill Impacts by Rate Class (before HST) – Guelph Hydro RZ**

| Total Bill Impacts | | | | |
|---|---|---|---|---|
| **Customer Class** | **Billing Units** | **Average Monthly Volume** | **2020 vs. 2019** | |
| | | | **$** | **%** |
| Residential | kWh | 750 | $ (2.07) | (1.9)% |
| GS<50 | kWh | 2,000 | $ (3.57) | (1.4)% |
| GS>50 to 999 | kW | 500 | $ (1,320.20) | (4.7)% |
| GS 1000 to 4,999 | kW | 1,000 | $ (546.93) | (0.8)% |
| Large User | kW | 7,500 | $ (9,120.80) | (1.6)% |
| Street Lighting | kW | 2,200 | $ (3,619.19) | (2.7)% |

Table excludes the impact of HST (13%) & Provincial Rebate (8%)