Ontario Energy Board
P.O. Box 2319
27th. Floor
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416- 481-1967
Facsimile: 416- 440-7656
Toll free: 1-888-632-6273

Commission de l'Énergie de l'Ontario
C.P. 2319
27e étage
2300, rue Yonge
Toronto ON M4P 1E4
Téléphone; 416- 481-1967
Télécopieur: 416- 440-7656
Numéro sans frais: 1-888-632-6273

BY E-MAIL

September 18, 2017

Attention: Ms. Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: Alectra Utilities Corporation
Application for Rates
OEB File Number EB-2017-0024

In accordance with Procedural Order No. 1, please find attached the Ontario Energy Board staff interrogatories on the application filed by Alectra Utilities Corporation.

Original Signed by

Martin Davies
Project Advisor, Rates
Major Applications

Attachment

cc: Parties to EB-2017-0024

Ontario Energy Board Staff Interrogatories
2017 Electricity Distribution Rate Application
Alectra Utilities Corporation (Alectra)
EB-2017-0024
September 18, 2017

General

G-Staff-1
Ref: GA Analysis
On July 24, 2017, the the OEB issued a new GA Analysis Workform for 2018 IRM applications. Given that Alectra filed its application before this date, please file a completed copy of the GA Analysis Workform for each Rate Zone.

G-Staff-2
Ref: IRM Models for all Rate Zones

The OEB issued an updated IRM Rate Generator Model on September 8, 2017. Please review the changes and file updated IRM Models for the applicable Rate Zones.

G-Staff-3
Ref: Ontario Energy Board *Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module* September 18, 2014, p. 18 and Table of Concordance of Application (All Rate Zones)
At the first reference above, it is stated that:

> Distributors must file, at the time of the cost of service application, a description of the actions the distributor would take in the event that the Board does not approve the ACM proposal. Similarly, distributors must file comparable information for any ICM requests at the time of the IR application.
>
> Distributors must also include a discussion on any offsets associated with each incremental project for which ACM or ICM treatment is proposed due to revenue to be generated through other means (e.g. customer contributions in aid of construction), at the time of the cost of service application, along with an estimate of the revenue requirement impact associated with those offsets.

At the second reference above, Section 3.3.2 of the Table of Concordance, items 8 and 9, it is stated that the Brampton, Enersource and PowerStream RZs are in compliance with the above referenced requirements but the reference given is not specific as to where this information is located.

Please provide a specific reference as to where these requirements have been met in the application, or if they have not been met, please provide the required information and an explanation as to why this information was not provided in the filed application.

G-Staff-4

Ref: E2/T2/S5, p.9, E2/T4/S5, p.9, E2/T1/S7, p.9

Alectra has proposed to clear the CBR B balance with a volumetric rate rider to five decimal places in 2018 for each of the Brampton, Enersource and Horizon Rate Zones.

a) Has Alectra ever billed rate riders to customers to 5 decimal places in the past?
b) Please confirm that Alectra's billing system has the ability to bill to 5 decimal places.
c) Please show the impact on an average customer bill if the rate rider was rounded to four decimal places for each of these rate zones.

Brampton Rate Zone

BRZ-Staff-1

Ref: Attachment 17, IRM Model Brampton RZ, Tab. 4 Billing Det.

The Embedded Distributor rate class has had the billing unit specified as kWh (cell C25), and no kW value has been populated in cell E25.

(a) Please explain the choice of kWh as opposed to kW for the billing determinant to be used on DVAs

BRZ-Staff-2

Ref: Attachment 17, IRM Model Brampton RZ, Tab. 16 RTSR-Rates to Forecast

The Embedded Distributor rate class has the volume set to zero, and the proposed RTSR set to be the same as the General Service 700 to 4,999 kW Service Classification.

(a) Please confirm that the forecasted total revenue required from the RTSR-Network is $29,006,718, and that Proposed RTSR-Network charges are designed to recover this entire amount from all rate classes excluding the Embedded Distributor service classification.
(b) Please confirm that the forecasted total revenue required from the RTSR-Connection is $21,496,983, and that Proposed RTSR-Connection charges are

designed to recover this entire amount from all rate classes excluding the Embedded Distributor service classification.

(c) Please confirm that any revenue collected from the RTSR-Network and RTSR-Connection charges applied to the Embedded Distributor class are designed to result in an over-collection of RTSRs.

BRZ-Staff-3
<u>Ref: Ex.2, Tab 2, Schedule 8, Page 2</u>
<u>Ref: Attachment 17, IRM Model Brampton RZ, Tab. 3 Continuity Schedule</u>

At first reference, the statement is made: "The IESO has not issued the Final Annual Verified Results for 2016". The IRM model contains transactions during 2016 of $579,460 at cell BN44.

(a) Please reconcile the apparent discrepancy of significant transactions absent verified results by the IESO.
(b) If verified results become available, does Alectra intend to update the application with a revised value or a request for disposition?

BRZ-Staff-4
<u>Ref: Ex.2, Tab 2, Schedule 10, Page 5</u>

In 2008, the Pleasant TS was put into service. The five year true-up Connection and Cost Recovery Agreement (CCRA) shortfall payment was completed in 2015 in the amount of $7.086 million.

(a) Which years of service did this payment apply to?
(b) Please provide the calculation of the $7.086 million payment amount, was the payment forecasted in the 2015 Cost of Service?
(c) If the answer to c is yes, when was the payment forecasted to be made?
(d) If the answer to c is yes, how much was the payment forecasted to be?

BRZ-Staff-5
<u>Ref: Ex.2, Tab 2, Schedule 10, Pages 4-6</u>

The Pleasant TS ten-year anniversary true-up is due in 2018, and anticipated to be $6.80 million.

(a) Please provide the calculation of the $6.80 million payment amount in 2018?
(b) Please provide the a schedule outlining the annual forecasted load used in setting the initial capital contribution at the time Pleasant TS was built, and the annual actual load which materialized.
(c) How much was the original capital contribution to Pleasant TS?
(d) Since this payment relates to several years of historic demand, would it have been possible to calculate a growing contingent obligation every year?
(e) If the answer to part d) is yes, has Hydro One Brampton or Alectra considered estimating and setting aside funds annually to smooth the impact of this cost?

BRZ-Staff-6
Ref: Ex.2, Tab 2, Schedule 10, Page 3

In the four years 2013-2016, the Brampton rate zone has invested an average of $2.8 million per year on Dx Expansion. In 2017 and 2018, planned spending is increasing to $5.192 million and $5.149 million respectively.

(a) Please explain the need for the significant increase in spending and why these funds could not be applied to the CCRA payment.

BRZ-Staff-7
Ref: Ex.2, Tab 2, Schedule 10, Page 3

The Brampton rate zone was approved to spend $709,000 for metering in 2015, and invested $5.651 million that year.

(a) Please explain the sudden unexpected spending.

BRZ-Staff-8
Ref: Ex.2, Tab 2, Schedule 10, Page 3

The Brampton rate zone has spent, or is planning to spend a total of $11.8 million on 4.16 kV to 27.6 kV voltage conversion over the eight years from 2013-2020, or an average of $1.5 million per year. In 2016, $11,000 was spent. Planned spending is $1.9 million in 2018, the second highest of all eight years.

(a) Why was the investment in 2016 lower than other years?

(b) Please explain the conversion project planned for 2018 and why it is required to be completed in 2018.

BRZ-Staff-9

Ref: Ex.2, Tab 2, Schedule 10, Page 4

The Brampton rate zone was approved to invest $5.065 million in an Enterprise Resource Planning (ERP) system in 2015. This investment is now forecasted for 2017.

(a) In 2017 year-to-date, how much has been invested in the ERP system?
(b) Is the ERP system now complete?

BRZ-Staff-10

Ref: E2/T2/S5, p.7, Table 55

This evidence is missing information on the rate riders that would apply to the Customer Group Class A non-RPP (January 1, 2016 – June 30, 2016) Class B (July 1, 2016 - December 31, 2016) Customers. Please file a completed Table.

BRZ-Staff-11

Ref: E2/T2/S5, p.9, Table 57

Alectra has calculated GA and CBR rate riders for its embedded distributor class.

a) Please state whether or not the embedded distributors are billed the actual GA and CBR charges as billed by the IESO.
b) Please state whether or not the rate riders for GA and CBR would apply to embedded distributor class.
c) Please update the rate riders as necessary and update IRM rate generator model as required.

BRZ-Staff-12

Ref: E2/T2/S6 and IRM Model Brampton Rate Zone – Tab 3 Continuity Schedule, Account 1588

1) In booking expense journal entries for Charge Type 1142 (formerly 142), and Charge Type 148 from the IESO invoice, please confirm which of the following approach is used:

a) Charge Type 1142 is booked into Account 1588. Charge Type 148 is pro-rated based on RPP/non-RPP consumption and then booked into Account 1588 and 1589, respectively
b) Charge Type 148 is booked into Account 1589. The portion of Charge Type 1142 equalling RPP-HOEP for RPP consumption is booked into Account 1588. The portion of Charge Type 1142 equalling GA RPP is credited into Account 1589.
c) Another approach. Please explain this approach in detail.

2) With regards to the Dec. 31, 2016 balance in Account 1589:
   a) Please indicate whether the items that flow into the account (i.e. revenues, expenses, CT 142) are based on estimates/accruals or actuals at year end.
   b) If there are reconciling items #1a, 1b in the GA Analysis Workform or if there are any proposed adjustments to Account 1589 in the DVA Continuity Schedule for the true up impacts, please quantify the adjustments that relate to each of the following items.
      i. Revenues (i.e. is unbilled revenues trued up)
      ii. Expenses - GA non-RPP (Charge Type 148) with respect to the quantum dollar amount and RPP/non-RPP pro-ration percentages
      iii. Credit of GA RPP (Charge Type 142) if the approach under IR 1b is used
   c) Please explain the credit adjustment of $1,619,355 for Account 1589 under column 'Principal Adjustments during 2016' on the Continuity Schedule.

3) With regards to the Dec. 31, 2016 balance in Account 1588:
   a) Please indicate whether the items that flow into the account (i.e. revenues, expenses, CT 142) are based on estimates/accruals or actuals at year end.
   b) If there are any proposed adjustments to Account 1588 in the DVA Continuity Schedule for the impacts of RPP settlement true up, please quantify the adjustment that relate to each of the following items.
      i. Revenues (i.e. is unbilled revenues trued up)
      ii. Expenses - Commodity (Charge Type 101)
      iii. Expenses - GA RPP (Charge Type 148) with respect to the quantum dollar amount and RPP/non-RPP pro-ration percentages
      iv. RPP Settlement (Charge Type 1142 - including any data used for determining the RPP/HOEP/RPP GA components of the charge type)

c) Please explain the debit adjustment of $803,139 shown in the column "Principal Adjustments During 2016" for Account 1588.

Enersource Rate Zone

ERZ-Staff-1
Ref: Rate Generator Model - Tab 3 Continuity Schedule

OEB staff notes that OEB's decision in EB-2013-0124 for the former Enersource Hydro approved a principal amount for disposition in Account 1595 (2009) of -$2,805,249 and interest of -$192,792 for a total of -$2,997,961.

In the current application, under the column heading "OEB-approved disposition in 2014", the continuity schedule does not show a balance for Account 1595 (2009). There is an amount in the 2010 sub-account, however OEB staff notes that there was no balance approved in EB-2013-0124 for Account 1595 (2010). OEB staff also notes that the amounts differ (i.e. the continuity schedule has an amount of -$2,807,104). OEB-approved interest is also in the incorrect row.

(a) Please provide an explanation for the discrepancies and verify all data inputs into these columns (i.e. AU and AZ).
(b) If any changes are required, please update the continuity schedule.

ERZ-Staff-2
Ref: Rate Generator Model – Tab 3 Continuity Schedule

The OEB's decision in EB-2013-0124 approved the disposition of -$10,611,807 for the former Enersource Hydro's Group 1 Accounts. In the current application, Alectra Utilities has entered the sum of balances disposed in Account 1595 (2013) as opposed to Account 1595 (2014). OEB staff also is unable to reconcile the amount entered (i.e. $10,153,475)

(a) Please explain why the approved amount is not entered in 2014 since that was the rate year the balances were disposed.
(b) Please reconcile the balance approved in the OEB's decision in 2014 to the amount entered in the continuity schedule in the current application. If any changes are required, please make them to the continuity schedule.

ERZ-Staff-3
Ref: Rate Generator Model – Tab 3 Continuity Schedule

OEB-approved disposition in 2016

EB-2015-0065 Partial Decision and Order shows the following approved amounts for disposition:

Account Name	Account Number	Principal Balance ($) A	Interest Balance ($) B	Total Claim ($) C=A+B
LV Variance Account	1550	1,743,891	49,704	1,793,595
Smart Meter Entity Variance Charge	1551	(69,617)	(1,582)	(71,198)
RSVA - Wholesale Market Service Charge	1580	(5,840,806)	(166,561)	(6,007,368)
RSVA - Retail Transmission Network Charge	1584	5,839,074	157,026	5,996,100
RSVA - Retail Transmission Connection Charge	1586	2,979,421	64,454	3,043,874
RSVA - Power	1588	(2,350,513)	(53,058)	(2,403,572)
RSVA - Global Adjustment	1589	11,160,843	263,430	11,424,273
Disposition and Recovery of Regulatory Balances (2010)	1595	(2,120,163)	(672,524)	(2,792,687)
Disposition and Recovery of Regulatory Balances (2011)	1595	3,054	(5,603)	(2,549)
Disposition and Recovery of Regulatory Balances (2012)	1595	(268,298)	(77,734)	(346,032)
Total Group 1 Excluding Global Adjustment - Account 1589		(83,957)	(705,878)	(789,835)
Total Group 1		11,076,886	(442,448)	10,634,438

The table shows balances in Account 1595 (2010), (2011), and (2012), however the continuity schedule in the current application shows balances in Account 1595 (2011), (2012), and (2013). In addition the $3,054 balance is not shown in the continuity schedule in row Account 1595 (2012) – an amount of $2,113 has been entered. These errors also make the OEB-approved interest amounts in the incorrect accounts.

a) Please reconcile all the points noted above.
b) The sum of all balances disposed is entered in Account 1595 (2014) – please explain why it was not entered in 2016 since that was the rate year the balances were disposed.

ERZ-Staff-4

Ref: Rate Generator Model - Tab 4 Billing Det. For Def. Var

OEB staff notes that the cell being referenced in U32 is incorrect as it is referencing the 2.1.7 RRR data as at December 31, 2016 on tab 3. The amount referenced should be CD43 on tab 3 which is the total claim for LRAMVA.

Please correct for this error.

ERZ-Staff-5
Ref: Rate Generator Model - Tab 11 RTSR Current Rates

A loss factor of 1.0000 has been entered for all rate classes. Enersource's current OEB-approved loss factor as per its Tariff of Rates and Charges is 1.0360. Please explain this discrepancy.

ERZ-Staff-6
Ref: Rate Generator Model, Tab 17 and Stretch Factor Assignment

On August 17, 2017, the OEB issued its 2016 benchmarking update for determination of 2017 stretch factor rankings. The former Enersource Hydro moved from a cohort of 2 to 3.

Please update tab 17 of the revised Rate Generator Model for this change.

ERZ-Staff-7
Ref: E2/T4/S6 and IRM Model Enersource Rate Zone – Tab 3 Continuity Schedule, Account 1588

1) In booking expense journal entries for Charge Type 1142 (formerly 142), and Charge Type 148 from the IESO invoice, please confirm which of the following approach is used:
    a. Charge Type 1142 is booked into Account 1588. Charge Type 148 is pro-rated based on RPP/non-RPP consumption and then booked into Account 1588 and 1589, respectively
    b. Charge Type 148 is booked into Account 1589. The portion of Charge Type 1142 equalling RPP-HOEP for RPP consumption is booked into Account 1588. The portion of Charge Type 1142 equalling GA RPP is credited into Account 1589.
    c. Another approach. Please explain this approach in detail.
2) With regards to the Dec. 31, 2016 balance in Account 1589:
    a. Please indicate whether the items that flow into the account (i.e. revenues, expenses, CT 142) are based on estimates/accruals or actuals at year end.
    b. If there are reconciling items #1a, 1b in the GA Analysis Workform or if there are any proposed adjustments to Account 1589 in the DVA Continuity Schedule for the true up impacts, please quantify the adjustment that relate to each of the following items.

i. Revenues (i.e. is unbilled revenues trued up)
ii. Expenses - GA non-RPP (Charge Type 148) with respect to the quantum dollar amount and RPP/non-RPP pro-ration percentages
iii. Credit of GA RPP (Charge Type 142) if the approach under IR 1b is used.

c. Please explain the credit adjustment of $2,514,038 shown in the column "Principal Adjustments During 2016" for Account

3) With regards to the Dec. 31, 2016 balance in Account 1588:
   a. Please indicate whether the items that flow into the account (i.e. revenues, expenses, CT 142) are based on estimates/accruals or actuals at year end.
   b. If there are any proposed adjustments to Account 1588 in the DVA Continuity Schedule for the impacts of RPP settlement true up, please quantify the adjustment that relate to each of the following items.
      i. Revenues (i.e. is unbilled revenues trued up)
      ii. Expenses - Commodity (Charge Type 101)
      iii. Expenses - GA RPP (Charge Type 148) with respect to the quantum dollar amount and RPP/non-RPP pro-ration percentages
      iv. RPP Settlement (Charge Type 1142 - including any data used for determining the RPP/HOEP/RPP GA components of the charge type)

   c. Please explain the debit adjustment of $2,500,544 shown in the column "Principal Adjustments During 2016" for Account 1588.

ERZ-Staff-8

<u>Ref: E2/T4/S5, p.7, Table 118</u>

This evidence is missing information on the rate riders that would apply to the Customer Group Class A non-RPP (January 1, 2016 – June 30, 2016) Class B (July 1, 2016 - December 31, 2016) Customers. Please file a completed Table.

ERZ-Staff-9
Establishment of New Deferral and Variance Accounts
Ref: E2/T4/S7 and Attachment 40 Accounting Order

Alectra - Enersource Rate Zone has filed an Accounting Order for OEB's approval for the Metrolinx Crossings Remediation Project related capital expenditures. The evidence indicates that the final design and identification of the specific number of crossings to be remediated have not been finalized by Metrolinx and project costs have not been developed.

a) When does Alectra - Enersource Rate Zone expect to have a business plan developed for this project, including project costs?
b) Is Alectra - Enersource planning to file an ICM for OEB's approval at a future date?
c) The Accounting Order states that Alectra Utilities proposes to apply to the OEB for any cost recovery of amounts recorded in the OEB-approved deferral accounting during the 2019 Annual Filing.
    i. Please provide details on how Alectra Utilities would be proposing to do cost recoveries (e.g. values to be used, what form would the rate rider take etc.)?
    ii. Account 1508 is a Group 2 account and is only disposed through a rebasing proceeding. Why does Alectra deem it appropriate to propose disposition of a Group 2 account in an IRM proceeding?
    iii. The costs in this proposed account are capital costs, and can only be added to the distributor's rate base at rebasing. How does Alectra propose to add the net book value to its rate base in an IRM proceeding?

ERZ-Staff-10
Ref 1: E2/T4/S8, p.1-3
Ref 2: Attachment 41/Attachment J

Page 2 of reference 2 shows the total revenue requirement for 2018 for Renewable Generation connections is $200,950, with $67,567 being a direct benefit to Enersource Rate Zone's customers and $133,384 to come from the Provincial Rate Protection.

a) Please confirm that Alectra Utilities is not planning to apply the rate rider to recover the direct benefit portion in 2018.
b) Please provide reconciliation between the capital amounts, OM&A and revenue requirement and the 2016 balances for Accounts 1531, 1532 and 1533.

ERZ-Staff-11
Ref: Tab 2 of LRAMVA Work Form (Attachment 42)

Alectra Utilities has applied for a debit balance of $2,146,406 in lost revenues associated with new CDM program savings between 2011 and 2015, including persisting savings from 2011 to 2014 in 2015 and carrying charges through to December 31, 2017 for the Enersource rate zone. There are no CDM forecast savings compared against 2011-2012 actual results. An LRAMVA threshold of 119.146 GWh is used as the comparator against 2013-2015 actual results.

Please confirm that the former Enersource rate zone did not have a CDM manual adjustment, and related LRAMVA threshold, approved as part of its 2008 Cost of Service application (EB-2007-0706).

ERZ-Staff-12
Ref: Tab 3 of LRAMVA Work Form (Attachment 42)

a) Please update row 14 in Table 3 to include the effective implementation dates of the approved rate orders that correspond with Enersource Hydro's rate years. (For example, for the 2015 rate year, please insert the effective implementation date of "January 1, 2015 to December 31, 2015").
b) Based on the effective implementation dates of Enersource Hydro's approved rates, please confirm accuracy of the months entered in row 16 and revise as appropriate.

ERZ-Staff-13
Ref: Tab 3-a of LRAMVA Work Form (Attachment 42)

a) Please provide a table that summarizes the allocation of program savings by year and initiative to Enersource Hydro's rate classes. Please ensure that the allocation percentages are consistent with those entered in Tabs 4 and 5.
b) Please discuss how the savings were allocated to Enersource Hydro's customer classes. In particular, please discuss how the savings for Commercial and Industrial programs were allocated across multiple rate classes.
c) Please discuss why certain rate class allocations do not add up to 100%. (For example, in row 57 of Table 5-a, 109% of savings from the 2015 Efficiency: Equipment Replacement Incentive Initiative are allocated across the GS<50 kW, General Service 50 to 499 kW, General Service 500 to 4,999 kW and Large Use classes.)

ERZ-Staff-14
Ref: Table 4-c, Tab 4 of LRAMVA Work Form (Attachment 42)
Ref: Tab 8 of LRAMVA Work Form (Attachment 42)

In Tab 8 of the LRAMVA work form, Alectra Utilities, for the Enersource rate zone, provided additional data from its billing system to support the LED Street Lighting Project savings claimed as part of the LRAMVA: 4,655.06 kW in 2013, 20,644.76 kW in 2014 and 39,021.34 kW in 2015. These savings are entered in Tab 4 as 5,059,891 kWh in 2013, with persisting savings counted for 2014 and 2015.

In Exhibit 2, Tab 4, Schedule 9 of the application, Table 124 shows that Enersource Hydro's Street Lighting customers are charged on a kW basis.

a) Please describe the nature of the LED Street Lighting Project that Enersource Hydro engaged in, including support received from the IESO if any, between 2013 and 2015.
b) Please confirm why Enersource Hydro has only claimed Street Lighting savings in 2013, and not in 2014 and 2015.
c) Please confirm whether the Street Lighting savings should be claimed on a kW basis, rather than on a kWh basis as filed.
d) Please confirm whether Enersource Hydro received any persistence information from the IESO related to this Street Lighting project. If not, please discuss how the persisting impacts of the reductions were developed (i.e., at 100%) due to the presence of this Street Lighting project.
e) Please discuss whether the Street Lighting savings are gross or net savings, and whether an adjustment for free ridership has been applied. Please provide all necessary assumptions, which were assumed in the calculation of savings.
f) Please revise Tabs 4 and 5 of the LRAMVA Work Form, as appropriate, if changes should be made to the Street Lighting savings claimed in 2013, 2014 and 2015.

ERZ-Staff-15
Ref: Table 4-d, Tab 4 of LRAMVA Work Form (Attachment 42)

a) In the 2014 LRAMVA work form, please state whether there is missing information in the following cells:
    i) Cells N507 and N510: It appears that 0 months of demand savings are claimed
    ii) Row 507, Columns Y to AL: It appears that there is no allocation of savings from Time of Use Savings Program to its customer classes.
    iii) Row 510, Columns Y to AL: It appears that there is no allocation of savings from LDC Pilots Program to its customer classes.

b) If the above noted cells in Table 4-d of Tab 4 have not been properly updated, please indicate the correct information below and revise Table 4-d of the LRAMVA work form.

Tab 4:

i) Cells N507 and N510
ii) Row 507, Columns Y to AL
iii) Row 510, Columns Y to AL

ERZ-Staff-16

Ref: Tab 5 of LRAMVA Work Form (Attachment 42)

Please discuss the rationale for claiming 12 months of demand savings from the following pilot programs:

- LDC Pilots in 2014
- Conservation Fund Pilot in 2015
- Loblaw Pilot in 2015

ERZ-Staff-17

Ref: Tabs 4 and 5 of LRAMVA Work Form (Attachment 42)
Ref: 2013 Decision and Order, p. 28-29 (EB-2012-0033)

In the 2013 Decision and Order in Enersource Hydro's cost of service application, the OEB noted that Enersource embedded 7.18 GWh of actual CDM savings from 2011 in the 2013 load forecast.

Please discuss the appropriateness of claiming lost revenues from 2011 programs in 2013 to 2015, provided that 2011 actuals were included in the 2013 load forecast.

ERZ-Staff-18

Please file an excel copy of Enersource's 2014 and 2015 Final CDM Annual Report, and the 2011-2015 Persistence Savings Report issued by the IESO.

ERZ-Staff-19

If Enersource has made any changes to the LRAMVA Work Form as a result of its responses to interrogatories, please file an updated LRAMVA Work Form.

ERZ-Staff-20

Ref: EB-2014-0219, Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, Pages 13-14

Excerpts from the above reference are reproduced below:

> The Board is of the view that projects proposed for incremental capital funding during the IR term must be discrete projects, and not part of typical annual capital programs. This would apply to both ACMs and ICMs going forward…
>
> The use of an ACM is most appropriate for a distributor that:
> - does not have multiple discrete projects for each of the four IR years for which it requires incremental capital funding;
> - is not seeking funding for a series of projects that are more related to recurring capital programs for replacements or refurbishments (i.e. "business as usual" type projects); or
> - is not proposing to use the entire eligible incremental capital envelope available for a particular year.

a) Please provide a discussion and specific justification about how each of Alectra Utilities' projects proposed for ICM funding for the Enersource rate zone meets the criteria above from the OEB's Report.
b) Please provide a discussion on Alectra Utilities' plans if the ICM was denied.

ERZ-Staff-21
<u>Ref: E2/T4/S11, p.4, table 129</u>

Please provide year to date actuals for the capital expenditures for 2017 in Table 129.

ERZ-Staff-22
<u>Ref: E2/T4/S11, p.4</u>

At the above reference, the following statement is made:

Based on the evaluation and comparison of available technical alternatives for each project, Alectra Utilities identified the preferable solution that addresses the relevant business risks and balances competing priorities in the most efficient and cost effective manner (though not necessarily least cost).

a) Are the preferable solutions referred to in the above statement identified using their risk adjusted costs, or something else?
b) If risk adjusted costs, please provide example calculations for several larger projects showing how risks are quantified and used to adjust the capital costs for the prioritization process.
c) If something else, please explain and show quantified calculations.

ERZ-Staff-23
<u>Ref: E2/T4/S11, p.5</u>

At the above reference, the following statement is made:

System access investments are necessary for the expansion and modification (including asset relocation) of Enersource RZ's distribution system, in order to provide customers access to adequate distribution services. Key drivers for system access investments include intensification growth in the downtown core of Mississauga and the implementation of the Light Rail Transit ("LRT") system.

a) Please identify Alectra's level of confidence for the need driving the System Access investment projects included in the Capital Plan. In other words, if a System Access project is being driven by a specific large customer connection, a new urban development or a transit upgrade, quantify Alectra's confidence that the driver will, in fact, occur during the forecast period.

b) If it is not possible to accurately quantify Alectra's confidence levels in each of the drivers, please provide a qualitative assessment in terms such as: Certain, Nearly Certain, High, Medium or Low

ERZ-Staff-24

Ref: E2/T4/S11, p.12

At the above reference, the following statement is made:

Typically, distribution transformers are run to failure due to their minor impact on system performance. However, potential oil leaks introduce significant environmental and safety risks, leading to the implementation of a proactive replacement project to remove such transformers from service.

Ref: E2/T4/S11, p.15

Table 130: List of Remaining Transformers to Replace (as of Dec. 31, 2016) – Enersource RZ

Transformer Type	PCB Transformers (Signs of Leaking)	PCB Transformers (Non-Leaking)	Non-PCB Transformers (Signs of Leaking)	Total
Single-Phase Pad Mount	3	95	733	831
Three-Phase Pad Mount	2	6	71	79
Vault Transformers	15	38	717	770
Pole Mount Transformers	0	31	533	564
Total	**20**	**170**	**2,054**	**2,244**

Ref: E2/T4/S11, p.16

At the above reference, the following statement is made:

The forecast expenditures associated with the transformer replacement project (i.e. to address units showing signs of leaks) is forecast to cost $8.4MM in each of 2017, 2018 and 2019, $6.4MM in 2020 and $4.3MM in 2021. The multi-year replacement project is scheduled to be completed in 2021.

The reactive replacement program to address substandard or failed transformers is forecast to cost $1.1MM in each year from 2017 to 2019 and $1.4MM in 2022.

a) Does this decision not to utilize a run-to-failure strategy for these assets represent a major change from Alectra's historical distribution asset management strategy?

b) Did Alectra's criteria for transformer inspection change recently, and thus prompt Alectra's changed from what is being characterized as 'typical'? If yes, describe in detail how the inspection process has changed.

c) Have new regulations been promulgated that have changed the risk consequences requiring a pre-emptive replacement program, or is this program driven by a change in Alectra's perceived risk?

d) Is it typical for other Canadian utilities to utilize a pre-emptive replacement approach for this class of assets?

e) Are replacements of PCB & leaking transformers and non-PCB & leaking transformers prioritized differently?

f) Does Alectra prioritize transformer replacements based upon the extent of assessed leaking?

    i. If yes, please identify the key parameters used to prioritize replacements and provide a revised Table 130 broken into categories based on those parameters.

    ii. If not, please describe how Alectra prioritizes between the transformers replacements listed in Table 130 above.

g) Has Alectra explored alternatives and risk mitigation strategies to address transformer leaks?

h) Are all of the forecast expenditures associated with the transformer replacement project addressed in the ICM?

    i. If not, please specify which expenditures are addressed as part of the ICM, and which are included in base capital.

i) Please define 'substandard' as used in the above statement *[Ref: E2/T4/S11, p.16],* and explain how 'substandard' is measured.

ERZ-Staff-25

Ref: E2/T4/S11, p.17

Table 131: Capital Expenditures by Category from 2012 to 2022 ($000s) – Enersource RZ

Category	Actual 2012	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020	Forecast 2021	Forecast 2022
System Access	$10,245	$6,690	$5,626	$12,253	$11,822	$8,114	$11,679	$13,797	$13,812	$12,752	$10,812
System Renewal	$16,224	$20,854	$31,244	$37,472	$35,196	$37,386	$40,910	$42,150	$41,520	$40,160	$36,940
System Service	$9,860	$8,167	$10,951	$16,297	$12,724	$11,147	$13,422	$13,407	$13,717	$13,522	$14,007
General Plant	$29,220	$6,831	$6,230	$9,546	$4,333	$6,798	$6,672	$7,580	$8,411	$6,753	$5,869
Total	$65,550	$42,541	$54,051	$116,047	$64,075	$63,445	$72,683	$76,933	$77,459	$73,186	$67,627

a) Please state whether the forecast year expenditures include all ICM expenditures?

b) Please show Table 131 excluding all ICM expenditures.

ERZ-Staff-26

Ref: E2/T4/S11, p.19-20

At the above reference, the following statement is made:

> *Subdivision Renewal Projects*
>
> *Capital expenditures for the subdivision renewal projects are driven by deteriorating underground system assets, particularly underground cables. Most of the cables installed in Mississauga before 1989 are either unjacketed or direct-buried, thereby with higher susceptibility to failure.*
>
> *Furthermore, as determined through Alectra Utilities' internal analysis of all cable failures for the Enersource RZ, in the period of January 2014 to January 2016, over 95% of failed cables were direct buried and without a jacket. In contrast, all jacketed primary cables installed in Mississauga over the last 22 years have experienced only a 4.8% failure rate. The subdivision renewal investments set out in the DSP are intended to address the increasing failure rates, which adversely impact the Enersource RZ's system reliability.*

a) What percentage of cables in the Enersource RZ were installed prior to 1989?

b) What percentage of cable failures from January 2014 to January 2016 were associated with cables installed prior to 1989?

c) What failure probability table is used for underground cables installed prior to 1989 and is it a different failure probability table than is used for cables installed after 1989?

d) Based on installed cable length, what is the total ratio of buried cables that failed from January 2014 to January 2016 versus the overall buried cable portfolio in the Enersource RZ?

e) What was the average age of the direct buried cables that failed during the 2014 - 2016 period?

f) Please provide Alectra's assessment of probability and consequence of failure for buried cables being replaced as part of the subdivision renewal projects under the ICM.

g) Is Alectra proposing to install all direct buried cable that it will be replacing into duct or conduit?

    i. If yes, has Alectra determined the incremental per unit cost of doing so, or the cost ratio of using direct buried cable versus cables installed in duct or conduit?

ERZ-Staff-27
Ref: E2/T4/S11, p.23

At the above reference, the following statement is made:

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

a) Based on the above statement, the majority of customers are satisfied with reliability but frustrated with electricity rates. However, Alectra is proposing to increase rates, in part due to an Incremental Capital Module ('ICM'), to improve reliability. Please explain how this aligns with the outcome of the customer engagement process?

b) During the customer engagement process, did Alectra explain the ICM process to its ratepayers, or discuss ICM versus non-ICM expenditure plans and forecast impacts to its ratepayers?

ERZ-Staff-28
Ref: E2/T4/S11, p.26

At the above reference, the following statement is made:

Table 138 – Bill Impacts for Incremental Capital Presented to Customers – Enersource RZ

Monthly Bill Impacts ($)	Capital Expenditures $MM	Residential (750kWh)	GS<50kW (2000kWh)	GS>50kW
System Access	$1.3	$0.02	$0.05	$0.98
System Service	$19.7	$0.11	$0.31	$5.82
System Renewal	$7.6	$0.29	$0.81	$14.95
Total	$28.6	$0.42	$1.17	$21.76

Further, for system service and system renewal projects, customers were asked which capital investment approach they would prefer Alectra Utilities to take in 2018 for the Enersource RZ: (i) system reliability is maintained (correlates with bill impacts identified in Table 138 above); (ii) system reliability eventually declines, calculated at 50% of the bill impacts identified in Table 138 above; and (iii) system reliability significantly declines.

a) How were the reliability performance predictions and associated bill impacts described in the reference developed? Please provide detailed calculations by which the predictions were determined, and if there are no detailed calculations, describe in detail how the reliability performance predicted.

b) Has Alectra calculated expected reliability performance for a scenario in which only formula driven base capital expenditures are made during the forecast period, excluding the proposed ICM capital expenditures? If yes, what were the calculated reliability results?

ERZ-Staff-29
Ref: E2/T4/S11, p.27-28

At the above reference, the following statement is made:

Based on its feedback from customers, Alectra Utilities revised its 2018 capital forecast from $83,118,772 to $77,233,772; and its ICM request from $28,643,339 to $24,247,022. No revision was made to the 2018 forecast or incremental capital funding request for System Access or System Renewal projects.

The System Service forecast and incremental capital funding request for 2018 was reduced by $4,432,750, which represents the removal of the Webb Municipal station construction.

a) Please reconcile the delta between the reduction in Alectra's 2018 capital forecast (i.e., $5,885,000) and Alectra's revised ICM request (i.e., $4,396,317).

b) Alectra's ICM expenditure request was reduced by $4,396,317 as a result of deferring the Webb Municipal Station construction project. Please explain why Alectra decided to defer the Webb Municipal Station construction project but not the York MS Substation Upgrade Project? What would be the impact of also deferring the York MS project?

c) It is mentioned on page 45 of the ICM [*Ref: E2/T4/S11, p.45]* that the York MS project is driven by growth in demand in the Meadowvale Business Park Area and by the need to update equipment and the configuration at the station to bring these in line with current standards and improve reliability. Please describe the relative contribution of each of these factors as project drivers.

ERZ-Staff-30
Ref 1: E2/T4/S11, p.27
Ref 2: Capital Module Applicable to ACM and ICM, Tab 10b Proposed ACM ICM Projects

The 2018 capital forecast of $77,233,772 noted at reference 1 does not reconcile to the 2018 Distribution System Plan Capex of $72,682,772 at reference 2.

Please reconcile.

ERZ-Staff-31
Ref: Capital Module Applicable to ACM and ICM, Tab 6 Rev_Requ_Check

OEB staff is unable to reconcile the “OM&A Expenses” amount of $52,564,731 in the Capital Module to Enersource Hydro’s previous cost of service RRWF as filed it its Draft Rate Order. OEB staff believes the amount should be $51,364,731.

Please reconcile this discrepancy.

ERZ-Staff-32
Ref 1: E2/T4/S11, p.27-28

Alectra Utilities notes that based on feedback from customers, it revised its 2018 capital forecast and ICM request for the Enersource rate zone. The system service forecast and incremental capital funding request for 2018 was reduced by $4,432,750 which represents the removal of the Webb municipal station construction.

a) Please provide what Alectra Utilities heard from its feedback from customers to make the decision that this specific project was to be removed as opposed to other discrete projects.
b) Was the removal of the Webb MS specifically mentioned in Alectra Utilities’ customer engagement and the effects of its removal?

ERZ-Staff-33
Ref: E3/T1/S1 – Innovative Customer Engagement Report, Page 2

A portion of the reference above is reproduced below:

Customer Engagement Activities	Methodology	Field Dates	Rate Zone(s)	Sample Size Target	Valid Completes
Online Portal: allows all customers from all rate zones to provide feedback to Alectra					
Online Feedback Portal - Enersource	Open Online	May 3-17, 2017	Enersource	N/A	**2,500**
Online Feedback Portal - PowerStream	Open Online	May 3-17, 2017	PowerStream	N/A	**7,093**
Online Feedback Portal - Brampton	Open Online	May 3-17, 2017	Brampton	N/A	**3,456**
Online Feedback Portal - Horizon Utilities	Open Online	May 3-17, 2017	Horizon Utilities	N/A	**4,546**
Quantify: Conduct representative surveys among residential, GS, and large user customers					
Enersource - Residential	Telephone	May 8-17, 2017	Enersource	n=500	**504**
Enersource - GS < 50 kW (Small Business)	Telephone	May 10-18, 2017	Enersource	n=200	**200**
Enersource - GS > 50 kW (Mid-Market)	Telephone	May 11-26, 2017	Enersource	n=200	**200**
Enersource - 5MW+ (Large Users)	Custom Online	May 26 to June 9, 2017	Enersource	Census (n=7)	**7**
PowerStream - Residential	Telephone	May 9-19, 2017	PowerStream	n=500	**516**
PowerStream - GS < 50 kW (Small Business)	Telephone	May 10-18, 2017	PowerStream	n=200	**201**
PowerStream - GS > 50 kW (Mid-Market)	Telephone	May 10-18, 2017	PowerStream	n=200	**201**

OEB staff notes that for the Enersource rate zone, customer consultations for the online feedback portal took place from May 3-17, 2017 and telephone surveys took place from May 8-17, 2017. Alectra Utilities received the Innovative Report on June 23, 2017, and ultimately filed its application with the OEB on July 7, 2017.

a) Please explain why only two weeks of customer consultation took place for the respective methods of engagement chosen by Alectra Utilities.
b) Between receiving the results of the Innovative Report and filing its application, a span of two weeks passed. Please explain why Alectra Utilities believes this time span is sufficient to factor in results from its customer engagement for a meaningful assessment of its proposed spending.

ERZ-Staff-34
<u>Ref: E3/T1/S1 – Innovative Customer Engagement Report, Page 2</u>

Alectra Utilties commissioned INNOVATIVE to help design, collect feedback and document its consultation processes as part of the developments of its 2018-2022 Distribution System Plan for the Enersource rate zone and its 2018 Incremental Capital Module (ICM). The summary provided by INNOVATIVE includes feedback from 2,500 customers for the Online Feedback Portal and 504 customers who participated in a telephone survey.

a) Besides an Online Feedback Portal and a telephone survey, were any other methods (ex. focus groups, town hall meetings etc.) of engagement utilized by Alectra Utilities (for both its DSP and ICM proposal)?
b) Does Alectra Utilities find the response rates acceptable for the Enersource rate zone as a basis for measuring customer satisfaction/wants? If so, why?

c) How much weight did Alectra Utilities give to the identified customer preferences in setting priorities for incremental capital projects?
d) What steps does Alectra Utilties intend to undertake to improve customer views of its performance. In your response, please address actions taken for commercial customers as well as other customers.

ERZ-Staff-35

Enersource DSP Feedback
Ref 1: E3/T1/S1 – Innovative Customer Engagement Report, Page 2
Ref 2: E3/T1/S1 – Innovative Customer Engagement Report, Page 16

Reference 1 states:

> The top 3 priorities for Alectra Utilities as identified by customers – in all rate zones and almost all customer classes – are:
> 1. Delivering reasonable distribution rates;
> 2. Ensuring reliable electrical service; and
> 3. Helping customers reduce and better manage their electricity consumption.

A portion of reference 2 is reproduced below:

> For the most part, customers in the Enersource rate zone support proactive replacement of aging infrastructure, prudent investments in tools and equipment, system capacity and modernizing the distribution system. The table below summarizes customer preferences collected from the **online feedback portal:**

Online Feedback Portal: Enersource DSP	Residential (n=2,438)	Small Business (n=62)
Run-to-Failure Approach		
Replace equipment before it breaks down	73% ✓	74% ✓
Wait until it breaks down	19%	21%
Replacing aging equipment in poor condition		
Invest	61% ✓	56% ✓
Lower investment	23%	26%
Forecasted plan for replacing aging infrastructure		
Proactively spend	39%	37%
Spend only what is needed	43%	37%
Focus on keeping rates as low as possible	8%	15%
General Plant		
Be wise with spending	72% ✓	66% ✓
Find ways to make do	22%	24%
Investments in New Technology		
New technologies are more of a luxury	20%	26%
Technology will save money in the long run	69% ✓	60% ✓
DSP Investment Alternatives		
Maintain [Res: $3.99; Small Business: $11.19 by 2022]	56% ✓	37%
Eventually Decline [Res: $1.40; Small Business: $3.97 by 2022]	17%	26%
Significantly Decline [No additional distribution charges by 2022]	16%	24%

Majority believe Enersource should spend at least what is needed to maintain reliability

a) Please explain the apparent disconnect between the statement that customers support proactive replacement of infrastructure and the 39% result to proactively spend under the heading "forecasted plan for replacing aging infrastructure".

b) Please explain the apparent disconnect between the top priority in reference 1 and the 8% result in keeping a focus on rates as low as possible under the heading "forecasted plan for replacing aging infrastructure".

ERZ-Staff-36

<u>Large Use Customer Feedback on Enersource's ICM Projects</u>

<u>Ref: E3/T1/S1 – Innovative Customer Engagement Report, Page 24</u>

At the above reference, 2/7 Large Use customers indicated that they wanted additional information before volunteering their preferences to the following question:

> *This proposed investment plan – which is subject to customer feedback and regulatory approval – could result in a monthly increase of [rate impact] on your organization's electricity bill in 2018.*
>
> *This represents an incremental increase of 1.7% on the amount remitted to Enersource OR a 0.1% increase on the total electricity bill amount for your organization.*

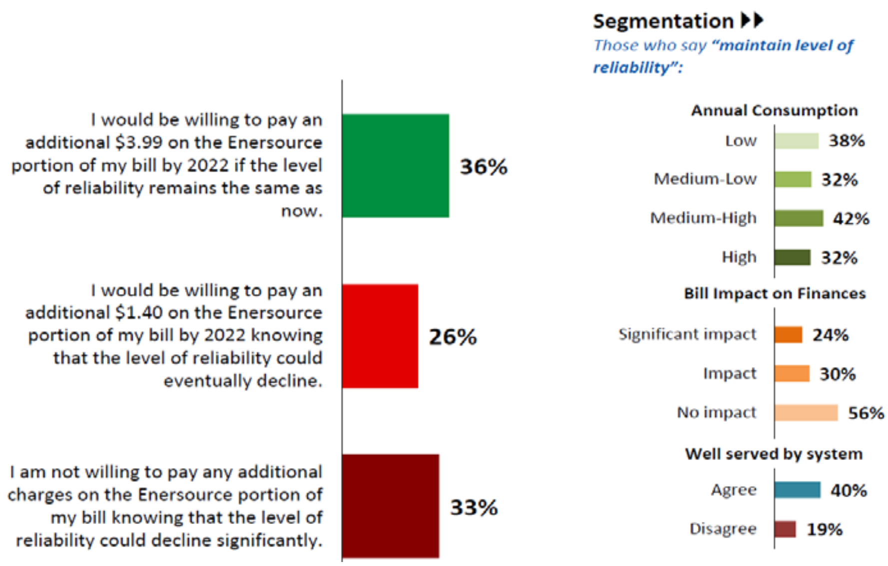
What is your opinion on this proposed rate increase in 2018?

Please state whether Alectra Utilities provided any additional information to the Large Use customers. If yes, what was the outcome? If no, please explain why not.

ERZ-Staff-37

Ref: Innovative Customer Engagement Report - Appendix 1.0 Enersource Telephone Survey Report, Residential 5-Year Capital Plan DSP, Pages 17-21

Pages 17-20 for the most part indicate some level of support for investment in system renewal, general plant, system service and modernizing the distribution system. This being said, the results from the DSP investment alternatives provided are reproduced below which show that a similar amount of customers are not willing to pay any additional charges when compared to those who are willing to pay an additional $3.99 by 2022 (the rest are willing to pay about half).



a) Please reconcile the two results.
b) Has Alectra Utilities adjusted its planned spending within any area of capital spending for the forecast period taking into account the feedback provided by its customers? If so, what adjustments were made?

ERZ-Staff-38
Ref: E2/T4/S11, p.31

Table 144 – 2018 Eligible Capital Projects by Category – Enersource RZ

Project Description	Capital Expenditures $
Road Widening Project - QEW (Evans to Cawthra)	$1,294,220
System Access	**$1,294,220**
Overhead Rebuild - Lake/John	$927,370
Overhead Rebuild - Church	$1,020,107
Leaking Transformer Replacement Project	$8,447,243
Subdivision Rebuild - Credit Woodlands Crt/Wiltshire	$1,548,270
Subdivision Rebuild - Glen Erin & Montevideo (Section 1)	$1,961,142
Subdivision Rebuild - Tenth Line Main Feeder	$1,135,398
Subdivision Rebuild - Folkway & Erin Mills Main Feeder	$1,032,180
Subdivision Rebuild - Glen Erin & Battleford	$2,064,360
Subdivision Rebuild - Walmart Cables	$1,548,270
System Renewal	**$19,684,339**
Substation Upgrade - York MS	$3,268,463
System Service	**$3,268,463**
Total Distribution Capital	**$24,247,022**

a) Has Alectra prioritized the projects listed in Table 144 above?
   i. If yes, please provide a ranked list of projects.
   ii. If no, why not?
   iii. If no, how is Alectra going to decide which projects to implement and which to defer if only a portion of the ICM expenditure is approved?

b) Has Alectra considered deferring lower priority projects included in the existing base capital budget envelope to create adequate headroom to implement the projects listed in Table 144?
   i. If yes, please describe in detail the results of this consideration?
   ii. If no, why not?

c) As part of Alectra's existing capital budget, were there any allowances or placeholders for unanticipated System Access projects? If yes, why weren't these funds allocated towards the QEW Road Widening Project?

d) For each of the eligible capital projects listed above, please describe the exceptional cause(s) that prompted the need for these projects and that became known since the base capital budget was originally set in 2013.

e) Underground cable and leaking transformer replacements appear to be high priority. Does Alectra's base capital (non-ICM) budget also include underground cable and transformer replacement programs?
   i. If yes, do the ICM line items simply represent an expansion of the cable and transformer replacement programs already included in the base capital budget?

ii. Are the projects listed in Table 144 the lowest priority cable and transformer replacement projects, or are they higher priority than the projects in the base capital list?

iii. If the latter, why aren't the ICM projects included in base capital, and the lower priority projects proposed for the ICM, since it is possible that some or all of the ICM projects may not be approved by the OEB.

f) Has Alectra considered deferring other System Renewal projects until these urgent cable and transformer issues have been mitigated?

i. If yes, which projects were considered for deferral to make room for the cable and transformer replacement projects, and why weren't they deferred?

ii. If no, why not?

ERZ-Staff-39

Ref: E2/T4/S11, p.32

At the above reference, the following statement is made:

Discrete and Material Projects

As identified on page 17 of the ACM report, amounts must be based on discrete projects, and should be directly related to the claimed driver. Each eligible capital project is a discrete project that meets or exceeds the materiality level for the Enersource RZ. Each project is distinct, unrelated to a recurring annual capital project, and has been evaluated in the asset management and capital planning process as required in 2018.

Ref: E3/T1/S1/A50, p.275

Table 55 – Material Capital Projects (2017-2022) [DSP]

Business Unit	Description	2017	2018	2019	2020	2021	2022	TOTAL
C0563 - U/G TX/Replace/Overhaul	PCB & Leaking Transformer Replacement Project - Underground	$4,784,004	$4,784,004	$4,784,004	$4,784,004	$3,162,640	$ -	$22,298,654
C0564 - O/H TX/Replace/Overhaul	PCB & Leaking Transformer Replacement Project - Overhead	$3,663,239	$3,663,239	$3,663,239	$1,617,108	$1,105,955	$ -	$13,712,781

a) Based on Alectra's breakdown of Material Capital Projects in Table 55 of the DSP, the leaking transformer replacement project appears to be a multi-year program of transformer upgrades. Please reconcile these expenditures with the

Alectra's claim that each capital project is a discrete project, unrelated to a recurring annual capital project.

b) How does the Leaking Transformer Replacement Project qualify as an ICM project?

ERZ-Staff-40

Ref: E2/T4/S11, p.35

At the above reference, the following statement is made:

> ***Glen Erin & Battleford Subdivision Rebuild***
> ***System Renewal: $2.06MM***
> *Project Description and Drivers*
>
> - *Since 2005, 17 underground cable failures have occurred in the Glen Erin and Battleford area, affecting 32,572 customers for a total of 191,139 outage minutes. The cables and transformers in the area are approximately 40 years old and are beyond the end of useful life. As per the 2016 ACA results, the cables in this area were flagged to be in very poor condition and are in need of immediate replacement.*

a) Please provide the SAIDI and SAIFI results for the Glen Erin and Battleford areas from 2011 to 2016.

b) Please provide the SAIDI and SAIFI results from 2011 to 2016 for the remaining project areas being rebuilt under the ICM:

   i. Glen Erin & Montevideo Subdivision Rebuild;
   ii. Credit Woodlands & Wiltshire Subdivision Rebuild;
   iii. Tenth Line Main Feeder Subdivision Renewal;
   iv. Folkway & Erin Mills Main Feeder Subdivision Rebuild; and
   v. City Centre Drive Rebuild.

c) Does Alectra's existing base capital budget envelope provide any allowance for subdivision rebuild projects?

   i. If yes, please provide a list of subdivision rebuild projects being implemented under the existing capital budget.
   ii. If yes, please explain why the subdivision rebuild projects included in the base capital budget took priority over the six (6) subdivision rebuild projects included in the ICM. What are the key differences and drivers between the base and ICM subdivision rebuild projects?
   iii. If yes, please provide the SAIDI and SAIFI results from 2011 to 2016 for the subdivision rebuild projects being implemented under this existing capital budget.

ERZ-Staff-41
<u>Ref: E2/T4/S11, p.41-42</u>

At the above reference, the following statement is made:

<u>Lake/John Area Overhead Rebuild</u>
<u>System Renewal: $0.93MM</u>

<u>Project Description and Drivers</u>

- *Through its inspection program in the Enersource RZ, Alectra Utilities identified a number of poles that are in poor condition (i.e. signs of rotting, mechanical damage, insect infestation, and cracking). Based on these inspections, and resistograph testing of wood poles' residual strength, the area south of Lakeshore Road W. between John Rd and Mississauga Rd was identified as requiring renewal, given the poor conditions of overhead assets, existence of leaning poles, identified porcelain insulators (which are prone to cracking and deterioration leading to failures and pole fires), and transformers showing signs of oil leaks or containing PCB.*

<u>Project Description and Drivers</u>

- *The project involves renewing the overhead system in this area to bring it in line with present day standards, including the replacement of 50 poles in poor condition (with average age exceeding 40 years), 22 poles with problematic types of porcelain insulators, and 2 transformers showing signs of leaks or containing PCB, as well as the installation of copper clad ground wires to deter theft of ground wires and of fibreglass switch brackets to minimize outages caused by animal contacts. New primary and secondary conductors will also be installed.*

<u>Church St. Area Overhead Rebuild</u>
<u>System Renewal: $1.02MM</u>

<u>Project Description and Drivers</u>

- *Through the inspection program, Alectra Utilities identified a number of poles as being in poor condition (i.e. signs of rotting, mechanical damage, insect infestation, and cracking). Based on these inspections, and resistograph testing of wood poles' residual strength, the Streetsville area east of Queen St. along Church St. was found to require renewal. This is due to the poor condition of overhead assets; existence of leaning poles; identified porcelain insulators (which are prone to cracking and deterioration leading to failures and pole fires); and transformers showing signs of oil leaks or containing PCB.*

<u>Project Description and Drivers</u>

- *The project involves renewing the overhead system in this area to present day standards, including through the replacement of 55 poles that are in poor condition (with an average age exceeding 40 years), 9 poles with problematic* *types of porcelain insulators, and 6 transformers that show signs of leaks or that contain PCB. The project will also involve the installation of copper clad alternative ground wires to deter theft, and the installation of fibreglass switch brackets to minimize outages caused by animal contacts. New primary and secondary conductors will also be installed*

a) What are the reliability impacts of the deteriorating poles based on historical performance for the Lake/John and Church St. areas mentioned above from 2011 to 2016?

b) Are these poles causing exceptional levels of outages? If yes, please provide evidence of this claim.

c) Most distribution utilities in Ontario would consider that a 40-year pole would have at least another decade of useful remaining life. What exceptional conditions are causing these poles to prematurely deteriorate?

d) Are there other areas in the Enersource RZ with pole conditions and vintages similar to those in the Lake/John and Church St. areas?

    i. If yes, why have these projects been prioritized and the others deferred?

    ii. Could these projects be considered as discretionary and candidates for deferral? If no, why not?

ERZ-Staff-42

<u>Ref: E2/T4/S11, p.43-44</u>

At the above reference, the following statement is made:

<u>Transformer Replacement Project</u>
<u>System Renewal: $8.45MM</u>
<u>Project Description and Drivers</u>

- *While distribution transformers are normally operated on a run to failure basis, the need to minimize safety, environmental, reliability, financial and regulatory risks has led to the replacement of 2,052 such transformers from 2013 to 2016. Transformer oil leaks at 103 sites led to $5.6MM in incurred costs for environmental remediation and $19.4MM in capital expenditures for transformer replacements from 2013 to 2016, which were not included in rates.*
- *As of January 1, 2017, a total of 2,244 in-service transformers need to be replaced (as identified based on inspections undertaken from 2013 to 2016) as part of the Enersource RZ's multi-year transformer replacement project. This total includes the 1,629 units flagged in the Kinectrics ACA as being in poor or very poor condition based on year end 2015 data, as well as additional transformers identified through inspections in 2016. Other problematic transformers requiring replacement (i.e. rusted or damaged*

units) that are beyond the scope of this project would be addressed on a reactive basis as part of the Alectra Utilities' ongoing transformer replacement program in the Enersource RZ.

a) Please show how Alectra assessed and quantified the safety, environmental, reliability, financial and regulatory risks that led to the replacement of the 2,052 transformers between 2013 and 2016 as referenced above. Were these replacements pre-emptive or post-failure?

b) Was Enersource unaware of the leaking transformer problem when it last re-based in 2013, or was it aware of the risk, but considered it to be acceptable at the time? If the latter, what has changed since 2013 to make the risk unacceptable?

c) Alectra states in the reference that $5.6 M in environmental remediation costs and $19.4M in capital expenditures for transformer replacement were not included in rates. How did Alectra account for these costs?

d) Table 6 of the DSP *[Ref: E3/T1/S1/A50, p.342]* cites capital expenditures of $36,170,000 for transformer replacements from 2013 to 2016. Please reconcile this value with the $19,400,000 cited in the above reference.

e) What total percentage of currently operating transformers are leaking oil?

    i. Has there been a step change in this ratio since 2013, has the ratio been trending upward since 2013, or has the ratio remained stable but the assessed risk increased? Please provide a detailed discussion.

f) Please explain why the 'other problematic transformers' were assessed as lower risk and not requiring pre-emptive replacement.

g) How does Alectra differentiate between the transformers associated with the Transformer Replacement ICM Project and the transformers in the base capital PCB & Leaking Transformer Replacement Project? What are the distinguishing characteristics?

h) Explain why this project should not be considered as an expansion of the existing PCB & Leaking Transformer Replacement Project?

ERZ-Staff-43
Ref: E2/T4/S11, p.45

Table 145 –Incremental Revenue Requirement – Enersource RZ

Incremental Revenue Requirement	Amount
Return on Rate base - Total	$1,539,083
Amortization	$589,204
Incremental Grossed Up PIL's	($166,176)
Total	**$1,962,111**

Please explain why the cost of the additional debt is not included in Table 145.

ERZ-Staff-44
Ref: E2/T4/S11, p.49

Table 148 – ICM Bill Impacts (Total Bill) – Enersource RZ

Rate Class	Unit	kWh	kW	ICM Rider HST	Rate incl.	% Increase vs. Total Bill
Residential	kWh	750		$	0.38	0.35%
General Service under 50 kW	kWh	2,000		$	1.09	0.36%
General Service 50 to 499 kW	kW	110,000	230	$	19.29	0.12%
General Service 500 to 4999 kW	kW	400,000	2,250	$	120.19	0.16%
Large Use	kW	3,000,000	5,000	$	483.27	0.11%
Unmetered	kWh	300		$	0.24	0.48%
Street Lighting	kW	33	0.1	$	0.05	0.56%

Ref: E2/T4/S12, p.1

Table 149 – Distribution Bill Impacts by Rate Class – Enersource RZ

Distribution Bill Impacts				
Customer Class	Billing Units	Average Monthly Volume	2018 vs. 2017	
			$	%
Residential	kWh	750	$ 0.41	1.67%
GS<50	kWh	2,000	$ 3.41	4.82%
GS 50-499 kW	kW	230	$ 138.58	11.86%
GS 500-4,999 kW	kW	2,250	$ 535.83	7.36%
Large User	kW	5,000	$1,368.85	4.68%
Street Lighting	kW	0.1	$ (2.79)	(101.95)%

Table excludes the impact of HST (13%) & Provincial Rebate (8%)

a) Please state whether 'Total Bill' in Table 148 above includes energy and transmission and global charge, or just the distribution delivery component that Alectra is responsible for?

b) Please explain the different factors that were included when calculating the bill impacts shown in Tables 148 and Table 149.

ERZ-Staff-45

Ref: E3/T1/S1/A50, p.v

At the above reference, the following statement is made:

The total net impact of such pacing and deferral adjustments is a $6.81MM reduction in capital expenditures over the 2017 to 2022 period.

The main investment needs that underpin the Enersource RZ DSP include load growth drivers in various areas of Mississauga, capital works made necessary by major infrastructure projects such as Light Rail Transit ("LRT"), the deteriorating condition of a sizeable portion of Enersource RZ's distribution assets (in particular, underground cables, substations, and overhead equipment), and environmental concerns relating to transformers exhibiting signs of oil leaks which need to be addressed in a timely manner.

a) Does the $6.81MM adjustment represent a reduction against Alectra's base capital envelope set under the OEB's base capital formula, or against the otherwise more significant increases that include the ICM projects?

b) Was the deteriorating condition of the underground cables, substations and overhead equipment assets known or suspected when the original base capital cost envelope was established and filed with the OEB, or has Alectra become aware of new information since then?

   i. If the latter, please provide all new information used to justify the projects and programs in the current capital portfolio related to these asset classes that was not known at the time of the original base capital filing.

ERZ-Staff-46

Ref: E3/T1/S1/A50, p.7-8

At the above reference, the following statement is made:

5) Asset Management

Alectra Utilities believes that by continuously improving its asset management practices and procedures, its ability to ensure reliable distribution system performance will be enhanced while overall costs and rate impacts will be more effectively controlled. In this regard, Alectra Utilities will continue to focus on the following development areas for improvement over the planning period of this Enersource RZ DSP:

- *Enabling asset analytics through integration of information systems (e.g. through Microsoft Business Intelligence);*

- *Creating an asset registry and condition assessment plan;*
- *Developing and implementing an Integrated Resource Plan to ensure adequate capacity and effective coordination with connected utilities and regional partners.*

a) Please describe in detail how Alectra plans to enable asset analytics through integration of information systems.

b) If Alectra is planning to create an asset registry and condition assessment plan, what are the asset management decisions documented in this DSP based upon?

ERZ-Staff-47

Ref: E3/T1/S1/A50, p.13

At the above reference, the following statement is made:

> *While Kinectrics' Asset Condition HI from the ACA results were a significant input to the analyses that formed the basis of this Enersource RZ DSP, additional elements of the 2016 ACA report (such as the projected flagged for action schedules) were not relied upon by Alectra Utilities. In this regard, the Company utilized internal analyses that were more specific to the Enersource RZ's system and customer requirements over the additional schedules and information provided by Kinectrics.*

a) Did Alectra rely upon the subjective judgment of experienced managers and utility staff in developing the project portfolio and then prioritizing the projects and programs comprising the filed capital plan?

b) Does Alectra's Asset Management Plan clearly identify where subjective judgment is to be used in assembling and prioritizing the project portfolio? If yes, please describe in detail.

c) Which specific capital plan projects and programs in this filing were prioritized primarily using subjective judgment?

ERZ-Staff-48

Ref: E3/T1/S1/A50, p.19

At the above reference, the following statement is made:

> *System Renewal.* *Timely replacement of Enersource RZ assets that have reached the end of life will enable the Company to save approximately $300,000 in O&M costs annually. This saving includes unplanned outage costs and other miscellaneous repair expenses. Alectra Utilities expects this annual saving to be sustainable with the implementation of initiatives outlined in this Enersource RZ DSP.*

a) For each of the following cost component categories:

   - System Access
   - System Renewal
   - System Service
   - General Plant

   Please answer the following questions:

   i. Please quantify the O&M savings in each year of the forecast period, and describe how the savings were calculated.

   ii. What is the capital cost associated with achieving the projected O&M savings?

   iii. How will Alectra monitor that the projected O&M savings are achieved?

ERZ-Staff-49

Ref: E3/T1/S1/A50, p.19

At the above reference, the following statement is made:

> *Based on costs incurred to date to remediate sites affected by oil leaks from transformers, Alectra Utilities expects to avoid approximately $50,000 for each site where future environmental remediation would otherwise become necessary.*

a) What is the anticipated number of sites "where future environmental remediation would otherwise become necessary", and how did Alectra calculate this number?

b) How were the expected environmental remediation costs of $50,000 per site calculated?

ERZ-Staff-50

Ref: E3/T1/S1/A50, p.51

At the above reference, the following statement is made:

> *Cost efficiency is focused on monitoring capital investment budgets compared to actual spend. Completion of the planned capital investments within each business unit (e.g. OH, Underground, Substations) is tracked through the Enterprise Resource Planning ("ERP") and allows Alectra Utilities to monitor and report on project performance compared to budget and identify any areas of concern (i.e. deviations from budget, project schedule, defined scope of work). Regular communications and meetings take place among representatives from scheduling, construction, engineering, and design to facilitate coordination, provide updates and*

prioritize ongoing projects to ensure that project work is completed on time and within budget.

a) What measures are taken by Alectra to ensure that capital investment budgets are not too conservative or do not contain larger than necessary contingencies?

b) What is Alectra's approach or policy in setting contingency for capital investment budgets?

ERZ-Staff-51

Ref: E3/T1/S1/A50, p.58

Table 7 - Trends in Reliability Indices 2010-2016 (excluding LOS, MEDs & Scheduled Outages)

KPI	2010	2011	2012	2013	2014	2015	2016
SAIDI	23.14	39.94	38.61	26.21	26.71	31.18	37.29
3-Yr Average SAIDI	23.61	31.63	33.90	34.92	30.51	28.03	31.73
SAIFI	0.99	1.53	1.34	0.86	0.94	1.42	0.98
3-Yr Average SAIFI	0.77	1.14	1.29	1.24	1.05	1.07	1.11
CAIDI	23.46	26.18	28.75	30.36	28.40	21.90	38.20
3-Yr Average CAIDI	32.31	28.32	26.13	28.43	29.17	26.89	29.50

a) SAIDI measures in 2011 and 2012 were higher than in 2016. What were the causes of the relatively high SAIDI during the 2011 - 2012 period?

b) Did Alectra take specific actions that resulted in the lower SAIDI scores between 2012 and the following three years, was the reduction based on external factors, or was the reduction based on a combination of these? Please describe in detail.

c) Please explain any parallels between actions taken by Alectra in 2013 aimed at improving SAIDI, and actions proposed by Alectra in this DSP to achieve a similar goal of lowering SAIDI measures?

ERZ-Staff-52

Ref: E3/T1/S1/A50, p.61

At the above reference, the following statement is made:

The Enersource RZ budgeted capital investments versus actual spend for 2015 and 2016 was calculated as 82.5% and 85.5%, respectively. Alectra Utilities aims to complete 100% of its budgeted capital investments. However, due to the merger initiative starting in 2015, some projects were not completed, resulting in lower than expected planned versus actual spend. Projects impacted by the merger included various IT and facility-related projects within the General Plan investment category.

a) Please catalogue the referenced capital investments that were not completed in 2015 and 2016, and identify if the investments have been:
    i. canceled permanently because they were no longer necessary after the merger;
    ii. added to the base capital or ICM expenditures addressed in this application, or;
    iii. deferred beyond the forecast period.

ERZ-Staff-53

Ref: E3/T1/S1/A50, p.62

Figure 12 - Per-Unit Cost of Transformation Installation

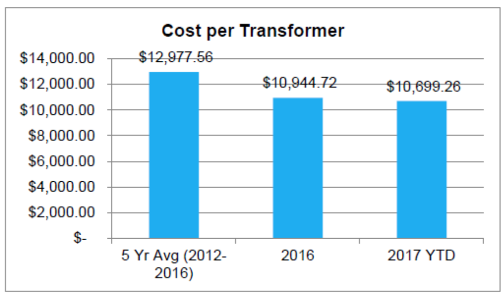
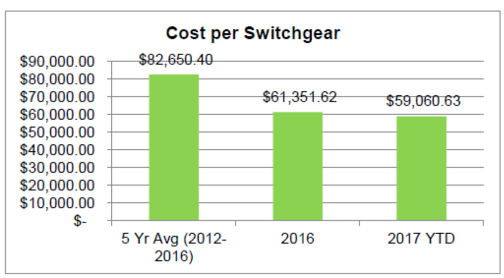


Figure 13 - Per-Unit Cost of Switchgear Installation



Please describe the cost elements comprising the achieved transformer and switchgear savings indicated in Figures 12 and 13 above.

ERZ-Staff-54
Ref: E3/T1/S1/A50, p.66

Table 9 - Customer Minutes by Equipment Failure (2011-2016)

Cause Codes	2011	2012	2013	2014	2015	2016
Underground Cable	2,881,575	2,727,177	1,720,513	1,610,094	2,764,938	4,979,324
Fuse	38,392	50,685	27,675	7,392	25,914	1,088
Insulator	42,884	156,102	301,820	170,207	399,569	142,659
Switchgears	421,281	49,230	221,229	544,465	144,472	197,823
Overhead Equipment	1,098,335	425,638	521,462	692,494	208,503	21,846
Others/Unknown	133,394	83,825	110,227	78,817	418,883	87,843
Splices	262,275	807,069	196,638	192,193	65,332	3,889
Switches	86,549	262,899	151,604	291,775	13,753	33,698
Elbows/Terminations	62,340	70,562	219,763	39,223	263,573	301,106
Transformers	192,913	236,178	292,664	181,559	154,391	167,404
Total	**5,219,938**	**4,869,365**	**3,763,595**	**3,808,219**	**4,459,328**	**5,936,680**

a) A general trend of decreasing failures between the 2011-2012 period and the 2013-2014 period can be observed in Table 9. Please explain whether this is a result of changes in O&M practices, capital expenditures, and/or other factors? Please provide details.

b) Please explain the reason for the decrease in failure rates from 2011 to 2016 for the following components:

   i. Overhead Equipment

   ii. Splices

   iii. Switches

ERZ-Staff-55
Ref: E3/T1/S1/A50, p.71

Table 11 - Number of Public Safety Concerns Recorded (2010-2016)

	2010	2011	2012	2013	2014	2015	2016
Public Safety Concerns	9	5	8	4	3	8	10

a) Does Alectra rate public safety concerns on a scale or are all concerns treated as posing a similar danger level to the public or Alectra workers?

   i. If a scale is used, please provide additional details describing how different risks are rated.

ERZ-Staff-56
Ref: E3/T1/S1/A50, p.82

At the above reference, the following statement is made:

> *In order to establish a realistic investment plan that takes into consideration customer expectations and preferences, public policy responsiveness, and stakeholder requirements, Alectra Utilities prioritizes projects and programs based on the following business values:*
>
> - *Regulatory/Public Policy Responsiveness;*
> - *Operational Effectiveness/Safety;*
> - *Customer Focus; and*
> - *Financial Performance.*

Projects are ranked based on which investments will have the greatest impact on the business values.

a) Is 'greatest impact' determined by subjective assessment, or is a score derived from quantifiable inputs, such as a risk assessment?

   i. Please provide concrete examples.

ERZ-Staff-57
Ref: E3/T1/S1/A50, p.91

At the above reference, the following statement is made:

> *Switchgear*
>
> *Since 2014, detailed field inspection of Enersource RZ switchgear units have been carried out, with findings being included in HI computation. Although the HI takes into account the overall condition of switchgear units inspected, it does not capture the higher failure risk associated with air-insulated units, which is evidenced by the 68 instances of failure involving such switchgear units in the Enersource RZ over the last five years. Over the last three years, the Enersource RZ has been replacing approximately 30 air insulated units each year. However, the average annual failure rate remains at 14, indicating that the number of units reaching end-of-life exceeds the replacement rate.*

a) What percentage of units reaching end-of-life are of the air-insulated type?

b) Please describe a typical switchgear failure as the term is used in this reference (i.e.: failure to isolate, flashover, catastrophic/explosive, any of the above)?

c) Please describe the consequence or range of consequence associated with a typical switchgear failure mentioned above. Is it primarily a safety concern, a financial concern, a customer outage concern, or other? Please provide details.

ERZ-Staff-58
Ref: E3/T1/S1/A50, p.112

At the above reference, the following statement is made:

> *A Risk Model Matrix is used to identify the risk associated with not undertaking an investment. Project needs are first reviewed to determine if they are a mandatory project. Mandatory projects are typically dictated by the OEB via the DSC or other regulatory instruments. Projects range from customer connections, to line relocations, to restoring power in a timely fashion. These projects are then prioritized based on whether they pose immediate concerns to safety, or the environment, or whether they constrain the operation of the system.*

a) Does Alectra consider other levels of safety and/or environmental concerns in addition to “immediate concerns” when prioritizing projects?

   i. If yes, what are different levels of concern and how does Alectra evaluate them?

   ii. If not, how does Alectra address concerns that are not categorized as immediate?

ERZ-Staff-59
Ref: E3/T1/S1/A50, p.133-134

Table 32 - Asset Health Index Summary

Asset Category		Population	Average Health Index	Health Index Distribution					Average Age
				Very Poor (< 25%)	Poor (25 - <50 %)	Fair (50 - <70 %)	Good (70 - <85 %)	Very Good (>= 85%)	
Substation Transformers	In Service	108	87%	0%	4%	8%	25%	63%	23
	Spares	12	82%	8%	0%	0%	33%	58%	33
Circuit Breakers	All	432	93%	< 1%	0%	5%	9%	86%	22
	High Voltage	56	96%	0%	0%	0%	4%	96%	23
	Low Voltage	376	93%	< 1%	0%	6%	9%	85%	21
Pole Mounted Transformers		5353	90%	3%	< 1%	5%	16%	76%	20
Pad Mounted Transformers	1 Phase	14261	86%	2%	4%	5%	25%	63%	21
	3 Phase	1860	93%	2%	2%	2%	11%	84%	16
Vault Transformers		3854	84%	6%	5%	6%	16%	67%	27
Pad Mounted Switchgear		834	88%	7%	< 1%	3%	2%	88%	15
Overhead Switches	44 kV	337	89%	0%	2%	5%	14%	79%	21
	27.6 kV	206	87%	0%	< 1%	7%	23%	69%	19
	Inline	2000	82%	0%	4%	10%	30%	56%	18
	Motorized	110	90%	0%	2%	9%	11%	78%	15
Underground Cables *Note that results are given in terms of conductor-km	Main Feeder	2238	82%	10%	2%	6%	12%	70%	18
	Distribution	4076	75%	17%	4%	10%	12%	57%	21
Poles	Wood	12436	73%	11%	5%	26%	16%	42%	27
	Concrete	9488	91%	3%	< 1%	11%	5%	80%	20

a) How are the Health Index results derived for underground cables? For example, are the results derived based on asset demographics, non-destructive testing, and/or other tests and assessments? Please provide details.

b) How are the Health Index results derived for wood poles? Please provide details.

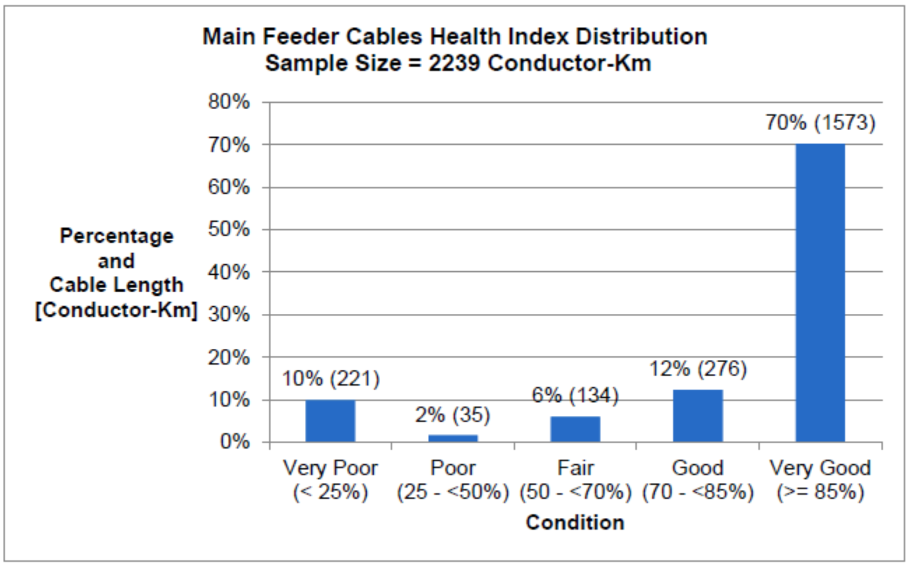
c) Please explain why substation transformers with very poor Health Indexes are kept as spares?

d) Trends observed in Table 32 indicate that more assets have Very Poor Health Index ratings than have Poor Health Index ratings. This seems contrary to the expectation for a normally distributed asset demographic profile (in which more assets would typically have Poor ratings than Very Poor). Please explain why this is the case.

ERZ-Staff-60

Ref: E3/T1/S1/A50, p.160

Figure 62 - Main Feeder Cables Health Index Distribution



a) Please discuss whether the Health Index Distribution in Figure 62 may be exaggerating the pool of Very Poor condition assets relative to the pool of Poor condition assets. What defining measure or parameter separates the two pools?

b) Please provide an updated Figure 62 with Health Index Distribution based solely on performance.

ERZ-Staff-61

Ref: E3/T1/S1/A50, p.162

At the above reference, the following statement is made

> *ACA HI determination for distribution class transformers is based on condition parameters related to age, service record, physical condition, signs of oil leaks, evidence of excessive thermal overloading, PCB content, and history of performance issues specific to manufacturers. Given regulatory requirements applicable to PCB-containing distribution assets and related oil spills, de-rating factors have been applied for Enersource RZ distribution transformers containing PCB mineral insulating oil, so as to accelerate the removal of such transformers from the distribution system and to mitigate the risk of spills.*

a) Please discuss whether or not the presence of PCBs impacts the asset's performance.

b) Should PCB content be considered as an environmental risk factor rather than a condition parameter used in the determination of asset Health Indexes?

ERZ-Staff-62

Ref: E3/T1/S1/A50, p.185

Table 42 - Subtransmission System Feeder Utilization

Year	Supply System	Number of feeders	Average M-class feeder load (A)	Number of feeders above 350 A	% of Planning Criteria Loading (350A)	Number of feeders above 450 A
2011	44 kV	47	303	14	87%	5
	27.6 kV South	26	258	8	74%	2
	27.6 kV North	36	292	12	83%	6
2016	44 kV	47	264	13	75%	4
	27.6 kV South	26	227	3	65%	1
	27.6 kV North	40	258	7	74%	2

Does Table 42 indicate that a certain number of feeders are operating over 350 / 450 amps during normal operating conditions, does it indicate what occurred on each feeder during the non-coincident peaks in 2011 (at 1606 MW) and in 2016 (1452 MW), or does it indicate something else? Please explain.

ERZ-Staff-63

Ref: E3/T1/S1/A50, p.190

At the above reference, the following statement is made:

> *All switchgear units identified for replacement would be replaced with solid-dielectric switchgear, which is expected to reduce safety concerns and maintenance costs. These units use a magnetic actuator for fault interruption which is proven to be safer for field operation compared to its air-insulated counterparts. Alectra Utilities expects these units to have an improved lifecycle in comparison to the air insulated units.*

Please state whether ‘improved lifecycle’ as used in the above statement refers to a longer asset life, less all-in-cost per year of operating life (including capex), or other? Please provide details.

ERZ-Staff-64
Ref: E3/T1/S1/A50, p.213

At the above reference, the following statement is made:

> *In terms of ways to identify transformer end of life, the degree of polymerization ("DP") value of insulating paper is one of the most determinative methods. In 2009, tests were performed on samples of paper insulation taken from actual vintage transformers decommissioned at that time. This test was performed to correlate the DP values to transformer end of life experienced in the decommissioned units. The outcome of these tests resulted in the implementation of a proactive substation power transformer replacement program targeting transformer vintages in excess of 49 years in service. Stations found to have transformers approaching 50 years in service were targeted for proactive replacement.*

a) Please confirm if the tests conducted in 2009 were performed on decommissioned or failure-driven transformer retirements.

b) Is Alectra proposing in this application to replace transformers based solely upon asset age, with no other parameters considered?

c) Is the proactive replacement of transformers approaching 50 years in service considered as an asset management best practice?

d) Does this policy vary depending upon the utilization rates of specific transformers?

ERZ-Staff-65
Ref: E3/T1/S1/A50, p.213

At the above reference, the following statement is made:

> *Ancillary components in stations where transformers are targeted for replacement are evaluated for opportunities for synergies when considering to proceed with the work. Considerations are made with respect to components and their:*
>
> - *Conformance to applicable station design, operational and protection standards;*
> - *Technical obsolescence;*
> - *HI; and*
> - *Oil containment feature.*

a) How does Alectra define synergy as it is used in this reference?

b) Has Alectra developed business cases demonstrating that it is less costly overall for ratepayers if asset replacements in substations are bundled?

   i. If yes, please provide a concrete example.

ERZ-Staff-66
Ref: E3/T1/S1/A50, p.245

At the above reference, the following statement is made:

> *As discussed in Section 2.2.3.9, the underground cables are flagged as one of the distribution assets with deteriorating conditions. Alectra Utilities recognizes that underground cables are one of the main causes of worsening reliability in the Enersource RZ (as evidenced by SAIDI trends). Enersource RZ customers, through customer engagement, have also recognized that the distribution system is aging and considerable portion of its system, namely underground cables, is reaching end of its useful life. This is further reinforced by a worsening reliability performance trend in the Enersource RZ, where over 80% of 2016 equipment failures were caused by cable faults). Alectra Utilities recognizes the need to address this trend through planned replacement of underground cables and renewal of subdivision underground system where multiple cable faults have occurred.*

a) Please confirm if over 80% of equipment failures in 2016 were caused by cable faults or were cable faults.

b) How did Alectra conclude that the trend described above is actually a trend, rather than a one-time spurious deviation from the mean?

    i. If it is a trend, why was Alectra unable to anticipate this trend in 2013 when it could have been identified and proposed for inclusion in the base capital expenditure envelope, rather than now when it must be addressed using an ICM?

c) If the Health Index calculation for underground cables is largely age-based rather than testing-based, why is the program being justified using the trend of failures witnessed in the last two years, rather than as an output from Alectra's long-term asset management program?

d) If Alectra does not conduct any non-destructive testing of underground cables, how can the Health Index be any worse than the age-only assessment of these assets?

e) Have recent cable failures convinced Alectra that the underground cables are deteriorating faster than would be expected based solely upon the age-related condition predicted using Kinectrics' Health Index methodology?

ERZ-Staff-67
Ref: E3/T1/S1/A50, p.245

At the above reference, the following statement is made:

> *Similar to underground cables, Alectra Utilities applies the overlaying methodology for overhead assets to identify the worst performing areas in the Enersource RZ.*

Alectra Utilities aims to identify poles for replacements, prior to failure, in order to ensure reliability and to mitigate against safety risks (e.g. falling poles).

a) Are poles often replaced based solely upon asset age?

b) Has Alectra prepared a business case to evaluate and optimize the tradeoff between the costs to ratepayers of premature pole replacements (including loss of asset service life) and the quantified consequences of running to failure?

   i. If yes, please provide this analysis.

   ii. If not, why not?

c) How does Alectra quantify consequence when evaluating the risk associated with pole failures? Is consequence treated as identical for all poles?

ERZ-Staff-68

<u>Ref: E3/T1/S1/A50, p.249-257</u>

Figure 94 - Enersource RZ Peak Demand Forecast - North 27.6kV Distribution System – Extreme Weather Scenario (1996-2035)

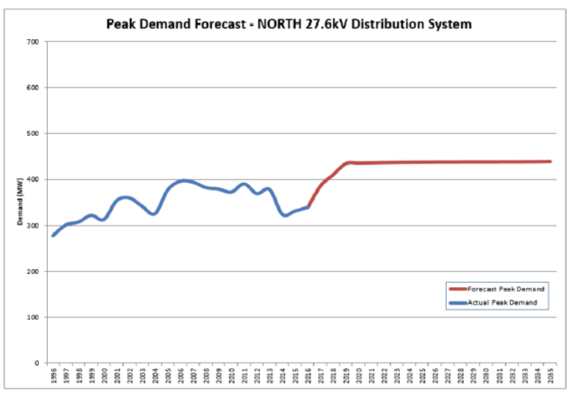


Figure 95 - Enersource RZ Peak Demand Forecast - South 27.6kV Distribution System – Extreme Weather Scenario (1996-2035)

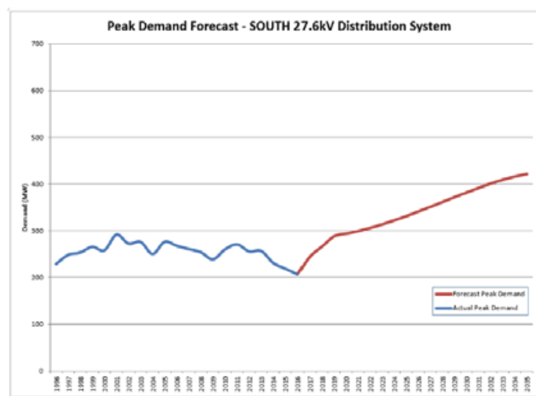


Figure 97 - Enersource RZ Peak Demand Forecast - West 44kV Distribution System – Extreme Temperature Scenario

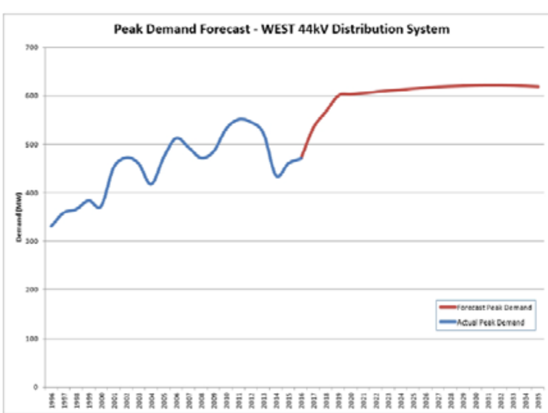
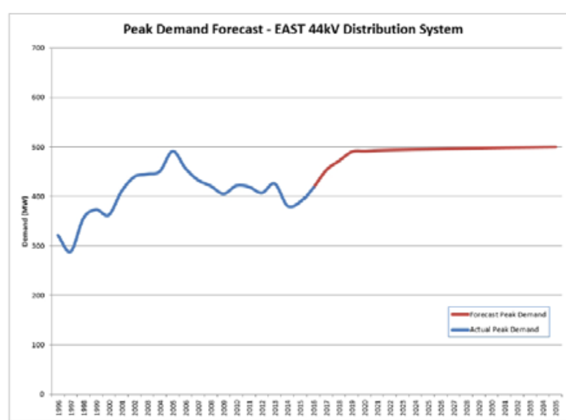


Figure 101 - Enersource RZ Peak Demand Forecast - East 44kV Distribution System – Extreme Weather Scenario (1996-2035)



a) The load growth forecast for years 2017, 2018 and 2019 shown in Figures 94, 95, 97 and 101 above seems high relative to actual load growth over the most recent 5 historical years. Assuming that the peak demand data for summer 2017 is now available, please provide updated Figures which include a comparison between Alectra's 2017 forecast loads and the actual year-to-date peak demand.

b) The growth projections in Figure 101 show an increase in peak demand to approximately the same level as the historic peak. Please explain if the existing infrastructure is able to accommodate the forecast peaks? If no, why not?

ERZ-Staff-69

Ref: E3/T1/S1/A50, p.252

At the above reference, the following statement is made:

> *Both sides of Lakeshore Road between Hurontario Street and Stavebank Road are characterized by low rise apartment buildings and mixed use commercial offices and restaurants. In the coming years, this area is expected to go through a major revitalization that will see its low rise buildings turned into mid-rise apartment buildings. The current 4.16kV distribution network is inadequate to supply projected demand, and Alectra Utilities is currently considering replacing its aging 4.16kV Enersource RZ distribution network with 27.6kV to accommodate future growth.*

a) What is the basis behind the anticipated future growth mentioned in the above reference? Has there been an increase in customer interconnection requests? Please provide details.

b) What is Alectra's level of confidence that the proposed 'major revitalization' will occur and that the projected electrical loads will materialize in the projected time frame? What is the basis of Alectra's confidence in these? Please provide details.

ERZ-Staff-70

Ref: E3/T1/S1/A50, p.256

At the above reference, the following statement is made:

> *In April 2015, the Province of Ontario announced that the LRT project will move ahead in support of the Moving Ontario Forward plan aimed at increasing transit ridership, reducing travel times, managing congestion, connecting people to jobs, and improving the economy. Currently, the construction of the LRT is expected to start in 2018 and the in-service date is expected in 2022. Consequently, Alectra Utilities has made provisions in its capital budgets under the System Access investment category to ensure adequate funds are available to conduct the work required to accommodate construction of the LRT (e.g. relocation of overhead assets).*

a) When did Alectra first become aware of the need to invest in the LRT System Access projects?

b) Does Alectra require certain conditions precedent to be in place prior to committing to design and construction of the relocation work? For example, if the LRT project were delayed or cancelled, are there protections in place to shield ratepayers from paying for any work performed unnecessarily?

ERZ-Staff-71

Ref: E3/T1/S1/A50, p.262

At the above reference, the following statement is made:

> *System Renewal spending is prioritized based on the condition of assets (determined through the ACA and inspections), project criticality, as well as the impact on reliability and safety. As one of the inputs to this Enersource RZ DSP, the ACA results provided by Kinectrics have helped the Company evaluate its existing programs in the Enersource RZ (renewal, sustainment, expansion, and regulatory) and develop new ones to address the required replacement rates for the asset groups considered in the ACA.*

a) Please explain the nature and function of each of the "existing programs in the Enersource RZ" cited in the reference, namely renewal, sustainment, expansion and regulatory.

b) Generally speaking, has the ACA resulted in Alectra evaluating its assets to be in better condition or worse condition than was thought prior to the ACA evaluation?

c) Has Alectra's assessment of the average remaining life of its assets increased or decreased based on the ACA results?

    i. Please quantify the change in remaining life for each asset class.

    ii. Will any changes in assessed remaining asset life result in increased costs for ratepayers, due to triggering earlier predictive replacements of assets in specific classes? Please explain and quantify.

    iii. Do the increased costs proposed in this filing represent the materialization of the changes in Alectra's understanding of asset condition and remaining life?

ERZ-Staff-72

Ref: E3/T1/S1/A50, p.286

At the above reference, the following statement is made:

> *Alectra Utilities has incorporated the identified customer priorities and preferences into the Enersource RZ DSP by pacing and deferring certain system expansion*

projects, as follows: (i) the Webb MS construction (including related feeder ingress and egress projects) has been deferred from an initial in-service date of 2018 to 2020; (ii) expansion investments related to LRT has been deferred and adjusted, resulting in lower 2018 expenditures and higher 2022 expenditures; (iii) the Mini-Britannia MS construction (including related feeder projects) has been deferred from a 2020 in-service date to 2022; and (iv) the Duke MS construction (including related feeder ingress and egress projects) has been deferred from an initial in-service date of 2022 to 2024.

a) Please describe the changes that enabled Alectra to defer the system expansion projects listed above.

b) What, if any, tradeoffs are being incurred due to the deferral?

c) Were these tradeoffs communicated to customers as part of the customer engagement activities?

ERZ-Staff-73

Ref: E3/T1/S1/A50, p.363-364

Figure 110 - Trend of Cable Failures in Number of Failures

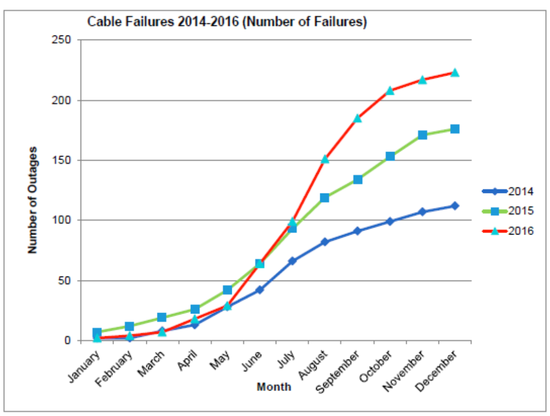
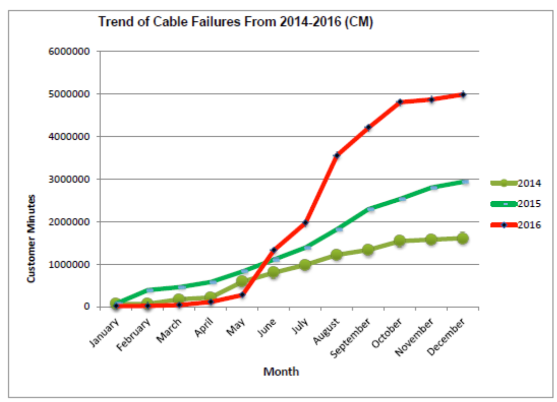


Figure 111 - Trend of Cable Failures in Customer Minutes



Please provide updated Figures 110 and 111 showing how 2017 cable failures are trending to date.

ERZ-Staff-74

Ref: E3/T1/S1/A50, p.364

At the above reference, the following statement is made:

For main feeder underground cables, the actual locations of the yearly rebuild projects are prioritized by using ten years' of underground cable failure history. However, for smaller 1/0 cables, locations for rebuild projects are selected by using the following criteria:

- *Ten years' of underground cable failure history;*
- *Transformers that are leaking oil;*
- *Transformers that contain PCB more than 2ppm; and*
- *Transformers that are located in backyards/rear lots.*

a) Please explain in detail why transformer characteristics are being used to prioritize underground cable replacements?

b) For all underground cable rebuilds that were selected based on transformer characteristics, please provide the estimated remaining useful life of the cable assets at the time they were being replaced.

ERZ-Staff-75

Ref: E3/T1/S1/A50, p.376

At the above reference, the following statement is made:

The visual inspection program and condition assessment (after conducting dry ice cleaning) is now being used to assess switchgear renewal needs in a proactive manner.

a) Please confirm if switchgear is being replaced proactively.

b) If yes, please explain why Alectra employs this policy (i.e., is it as a result of safety concerns, financial concerns, or other?).

ERZ-Staff-76

Ref: E3/T1/S1/A50, p.362

Table 72 - Number of Cable Failures

Number of Cable Failures per Month													
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	**Total**
2014	2	0	6	5	15	14	24	16	9	8	8	5	**112**
2015	7	5	7	7	16	22	29	26	15	19	18	5	**176**
2016	2	2	3	11	11	35	35	52	34	23	9	6	**223**

Ref: E3/T1/S1/A50, p.377

At the above reference, the following statement is made:

In addition to cable spot replacement, this program also incorporates heat shrink splice replacement. In the past, several thousand heat shrink cable splices were installed on the system. Later, it was discovered that a vast majority of them failed prematurely. As a result, it was decided that a proactive approach would be taken, and all known heat shrink splices would be replaced with new cold shrink splices that perform considerably better.

a) In what year or years was heat shrink cable splicing phased out and cold shrink splicing phased in?

b) For the underground cable failures listed in Table 72, how many failures are related to heat shrink splices?

Horizon Rate Zone

HRZ-Staff-1
Ref: Exhibit 2 – Tab 1 – Schedule 1 page 3

Horizon requested on page 3 item e the recovery of the remaining balance of stranded meter assets. In the settlement agreement the stranded meter assets were to be recovered over 3 years from 2015-2017.

a) Please provide evidence on the remaining balance of stranded meter assets to be recovered in 2018.

HRZ-Staff-2
Ref: Table 22 – Cost of Power 2018 Annual Filing vs. Custom IR – Horizon Utilities RZ

Horizon stated that the updated Cost of Power amounts incorporate (i) the RPP price increase effective May 1, 2017; (ii) Hydro One 2016 UTRs and STRs approved by the OEB January 14, 2016; (iii) an update to the Alectra Utilities demand for the Horizon Utilities RZ from 2015 to 2016 actuals in the RTSR model; (iv) an increase to the SME charge as a result of an update to the number of customers; (v) a change in the ratio of RPP to non-RPP volumes; and (vi) a decrease in the Wholesale Market Service Rate of $0.0008/kWh from $0.0044/kWh to $0.0036/kWh as approved by the OEB on November 2015; and (vii) an increase in the Rural and Rural or Remote Electricity Rate Protection (“RRRP”) Charge from $0.0013/kWh to $0.0021/kWh.

a) Please provide the electronic calculation for the 2018 Annual Filing column in Table 22 – Cost of Power 2018 Annual Filing vs Custom IR – Horizon Utilities RZ.

b) Please update the Cost of Power calculation with the Fair Hydro Plan Remote Electricity Rate Protection charge of $0.0003/kWh and new RPP rates effective July 1, 2017
c) Is the updated number of customers for the Smart Meter Entity charge actuals or a forecast? If it is a forecast, please provide evidence that an update to the customer forecast was accepted by the parties in the settlement proposal.

HRZ-Staff-3

Ref: Table 3 – 2016 Capital Additions – 2016 Actual vs. Custom IR application (EB-2014-0002) - Horizon Utilities RZ

Horizon stated in table 3 that the net capital additions in 2016 were $44,295,265, $3,147,731 higher than the approved capital additions of $41,147,533.

a) Please provide the approved 2016 asset continuity schedule and the actual 2016 asset continuity schedule.
b) Please provide a list of capital projects completed in 2016 compared to a list of planned capital projects.
c) Please provide a comparison of approved capital expenditures to actual expenditures for each investment category.

HRZ-Staff-4

Ref: Table 24 – Impact to Revenue Requirement due to Update of Cost of Capital Parameters – Horizon Utilities RZ

Ref: Attachment 4 - Revenue Requirement Work Form 2018 V7.02 Horizon Utilities RZ 2017-0707

Horizon provided the rate base and revenue requirement after the cost of power and cost of capital parameter updates in table 24. Horizon also provided the same information in the revenue requirement work form model.

a) Please explain the variance between the rate base in column “2018 annual filing after COP and COC parameter update” and the rate base in the revenue requirement work form model

HRZ-Staff-5

Ref: Table 26 – Calculation of 2016 regulatory ROE – Horizon Utilities RZ

Horizon provided the calculation for the 2016 Earnings Sharing Mechanism in table 26. Each of the columns in table 26 start with an opening balance from regulatory net income including merger costs. Horizon also stated that an update to the actual earnings resulted in a $33,508 difference in the earning sharing amount.

a) Please explain the variance in the opening balance for the “2016 actuals ESM” column

b) Please explain the reasons for the $33,508 difference and why this was not captured in the RRR filing.

HRZ-Staff-6
Ref: Attachment 9 – RTSR Work Form Horizon Utilities RZ

Horizon has calculated the RTSRs based on 2016 Hydro One Uniform Transmission Rates (UTRs).

a) Please update the RTSR Work Form with 2017 UTRs when they become available.

HRZ-Staff-7
Ref: Attachment 6a - Bill Impact Tariff Sheet
Ref: Table 45 - Distribution Bill Impacts by Rate Class
Ref: Table 46 - Distribution Bill and Rate Rider Impacts by Rate Class
Ref: Table 47 – Total Bill Impacts by Rate Class (before HST)

Horizon provided bill impacts for each rate class in table 45-47 and the same corresponding table in the Bill Impact model.

a) Please reconcile the bill impacts between the tables and the model for the residential and GS<50 rate class

HRZ-Staff-8
Ref: Attachment 6b - IRM Model Horizon Utilities RZ_20170707

Horizon proposed to dispose of LRAMVA amounts but the continuity schedule in the reference IRM model does not show a balance.

a) Please reconcile the continuity schedule with the LRAMVA balance.

HRZ-Staff-9
Ref: LRAMVA Work Form

Horizon has proposed to recover LRAMVA resulting from Conservation and Demand Management (CDM) activities in 2013 through 2015. The total amount requested for disposition is a debit of $1,281,317 including forecasted carrying charges of $46,279 through to December 31, 2017.

a) Please explain why in the LRAMVA model tab 3. Distribution Rates, Horizon has manually adjusted historical rates by ($0.0001).
b) In the LRAMVA model tab 4. 2011-2014 LRAM, Horizon has included 2011 persistence amounts in the 2012 lost revenue. Please explain why Horizon has

included 2012 lost revenues were included when Horizon is proposing to recover LRAMVA resulting from CDM activities in 2013 through 2015.

c) Please explain why 2012 carrying charges are included when Horizon is proposing to recover LRAMVA resulting from CDM activities in 2013 through 2015.
d) If the 2012 amounts were incorrectly populated in Table 1-a of Tab 1, please remove the 2012 savings claimed as part of the LRAMVA by deleting the 2012 distribution rates entered into Tab 3. (Please note: only the respective distribution rates that correspond to the period of the LRAMVA claim should be included).

HRZ-Staff-10

Ref: Tab 1 of LRAMVA Work Form

Ref: Tab 1-a of LRAMVA Work Form

Ref: Tab 8 of LRAMVA Work Form

Cell I65 in Tab 1 calculates actual street lighting savings to be claimed in 2015. Horizon notes in Tab 1-a that these savings were realized by implementing LED streetlight projects in the City of Hamilton in 2015, as approved by the OEB. Horizon provided billing data, before and after the retrofit, to show the reduction on peak demand of 11,238 kW. Based on distribution charge of $7.4960/kW for street lighting customers, Horizon is claiming $84,239.37 on street lighting savings in 2015 that has been included with the LRAMVA disposition.

a) Please describe the nature of the LED Street Lighting Project that Horizon engaged in, including support received from the IESO if any, in 2015.
b) Please confirm whether Horizon received any persistence information from the IESO related to this street lighting project. If not, please discuss how the persisting impacts of the reductions were developed (i.e., at 100%) due to the presence of this street lighting project.
c) What was the free ridership assumption used? If there was no free ridership assumption applied, please explain why.
d) Please revise Tabs 1 and 8 of the work form, as appropriate, if changes should be made to the street lighting savings claimed in 2015.

HRZ-Staff-11

Ref: Tab 2 of LRAMVA Work Form

Ref: 2011 COS Decision (EB-2010-0131), p. 24 of 72

In Horizon's 2011 COS Decision, the OEB approved 28.142 GWh for the CDM adjustment or a reduction to forecast by 10%. The 2015 LRAMVA threshold was 19,534,205 kWh and 34,728 kW.

a) Please discuss how the breakdown of the 2011 LRAMVA threshold of 28,142,000 kWh was determined.
b) Please confirm whether that the 2015 LRAMVA threshold included actual CDM savings up to 2014.
c) Please confirm the source of the 2015 LRAMVA threshold. Please include details from Appendix 2-I or make reference to the approved threshold from the Settlement Agreement.

HRZ-Staff-12
Ref: Tab 3 of LRAMVA Work Form

Tab 3 provides a template for distributors to input distribution rates by customer class. LDCs should input the distribution rates for the years that are applicable to the LRAMVA disposition.

a) Please update row 14 in Tab 3 to include the effective implementation dates of the approved rate orders that correspond with Horizon's rate years. (For example, for the 2015 rate year, please insert the effective implementation date of "January 1, 2015 to December 31, 2015").
b) Based on the effective implementation dates of Horizon's approved rates, please confirm accuracy of the months entered in row 16 and revise as appropriate.

HRZ-Staff-13
Ref: Tabs 4 of LRAMVA Work Form
Ref: Tabs 5 of LRAMVA Work Form

The calculation of lost revenue amounts is based on the allocation of CDM savings to their respective rate classes. LDCs should provide supporting documentation and rationale for its proposal to support its LRAMVA calculations.

a) Please provide a table that summarizes the allocation of program savings by year and initiative to Horizon's rate classes.

b) Please discuss how the savings were allocated to Horizon's customer classes. In particular, please discuss how the savings for Commercial and Industrial programs were allocated across multiple rate classes.

HRZ-Staff-14
Ref: LRAMVA Work Form

a) If Horizon has made any changes to the LRAMVA work form as a result of its responses to interrogatories, please file an updated LRAMVA work form.
b) Please file an excel copy of Horizon's 2014 and 2015 Final CDM Annual Report, and the 2011-2015 Persistence Savings Report issued by the IESO.

HRZ-Staff-15

Ref: E2/T1/S6, p.7, Table 30

Alectra, Horizon Utilities Rate Zone has calculated variable charge rate riders for the Residential customer class for Account 1508, Sub-account Earnings Sharing Variance Account, a Group 2 account.

On April 2, 2015, the OEB released its *Board Policy: A New Distribution Rate Design for Residential Electricity Customers (EB-2012-0140),* which stated that electricity distributors will transition to a fully fixed monthly service charge for residential customers. Generally speaking, distributors must propose a fully fixed rate design for charges applicable to the residential class provided that those charges are specifically related to the distribution of electricity. Examples of distribution-specific charges include: Group 2 Deferral and Variance Accounts.

Please recalculate and file the rate riders as applicable.

HRZ-Staff-16

Ref: E2/T1/S2, p.10-11 – Capital Investment Variance Account (CIVA)

a) OEB staff notes that the CIVA account approved in EB-2014-0002 was asymmetrical in nature, where the revenue requirement impact of only cumulative underinvestment in capital was to be captured. Please confirm that since the 2016 actual capital additions were greater than the approved level, that there is no entry made in the Capital Additions Variance Account.
b) If any entries made in the Capital Additions Variance Account, please file a schedule to indicate the amounts recorded annually in Account 1508, Sub-account CIVA since 2015.

HRZ-Staff-17

Ref: E2/T1/S2, p.13, lines 1-9 – Efficiency Adjustment

Prefiled evidence indicates that Alectra Utilities Horizon Utilities Rate Zone is to update the Efficiency Adjustment after the OEB has issued its 2017 Benchmarking Update for determination of Stretch Factor Assignments for 2018. OEB staff notes that the OEB issued this report in July 2017.

Please update the evidence with respect to the Efficiency Adjustment as necessary.

HRZ-Staff-18

Ref: E2/T1/S7, p. 7 and IRM Model HRZ – Tabs 6A and 7A

Exhibit 2 indicates that HRZ had 3 new Class A customers effective July 1, 2016. However, the IRM Model Tab 6A and 7A, each show 2 new Class A customers.

a) Please confirm the number of new Class A customers.
b) Please amend the evidence as necessary.

HRZ-Staff-19

Ref: E2/T1/S7, p. 8, Line 9, Table 36 and IRM Model HRZ

On line 9 of Exhibit 2, Alectra states that the total amount to be disposed of by rate riders is ($6,298,554). However, Table 36 shows this amount to be ($7,298,317).

a) Please clarify and amend the evidence as applicable.

Table 36 shows an amount for Account 1588 twice, once a debit of $588,675 under IRM 14, and another amount for Power for a credit of $1,134,428. The latter amount is the total claim for this account on the IRM Model.

b) Please clarify what the debit amount under IRM 14 for $588,675 is regarding, and how is it being disposed to the variance customer classes.
c) Please provide reference to where the rate rider is to All customers – DVA Rate Rider 1 (per Table 36) is calculated in the evidence.

HRZ-Staff-20

Ref: IRM Model Horizon Utilities Rate Zone – Tab 3 Continuity Schedule, 1589

On July 24, 2017 the OEB issued a new GA Analysis Workform for 2018 IRM applications. Given that Alectra filed its application before this date, please file a completed copy of the GA Analysis Workform.

HRZ-Staff-21

Ref: E2/T1/S8 and IRM Model HRZ – Tab 3 Continuity Schedule, Account 1588

1) In booking expense journal entries for Charge Type 1142 (formerly 142), and Charge Type 148 from the IESO invoice, please confirm which of the following approach is used:
   a) Charge Type 1142 is booked into Account 1588. Charge Type 148 is pro-rated based on RPP/non-RPP consumption and then booked into Account 1588 and 1589, respectively
   b) Charge Type 148 is booked into Account 1589. The portion of Charge Type 1142 equalling RPP-HOEP for RPP consumption is booked into Account 1588. The portion of Charge Type 1142 equalling GA RPP is credited into Account 1589.
   c) Another approach. Please explain this approach in detail.

2) With regards to the Dec. 31, 2016 balance in Account 1589:
   a) Please indicate whether the items that flow into the account (i.e. revenues, expenses, CT 142) are based on estimates/accruals or actuals at year end.
   b) If there are reconciling items #1a, 1b in the GA Analysis Workform or if there are any proposed adjustments to Account 1589 in the DVA Continuity Schedule for the true up impacts, please quantify the adjustments that relate to each of the following items.
      i. Revenues (i.e. is unbilled revenues trued up)
      ii. Expenses - GA non-RPP (Charge Type 148) with respect to the quantum dollar amount and RPP/non-RPP pro-ration percentages
      iii. Credit of GA RPP (Charge Type 142) if the approach under IR 1b is used

3) With regards to the Dec. 31, 2016 balance in Account 1588:
   a) Please indicate whether the items that flow into the account (i.e. revenues, expenses, CT 142) are based on estimates/accruals or actuals at year end.
   b) If there are any proposed adjustments to Account 1588 in the DVA Continuity Schedule for the impacts of RPP settlement true up, please quantify the adjustment that relate to each of the following items.
      i. Revenues (i.e. is unbilled revenues trued up)
      ii. Expenses - Commodity (Charge Type 101)
      iii. Expenses - GA RPP (Charge Type 148) with respect to the quantum dollar amount and RPP/non-RPP pro-ration percentages

iv. RPP Settlement (Charge Type 1142 - including any data used for determining the RPP/HOEP/RPP GA components of the charge type)

c) Please explain the credit amount of $988,885 shown in the column "Principal Adjustments During 2016" for Account 1588.

PowerStream Rate Zone

PRZ-Staff-1
Ref: E2/T3/S3, p.2 and Ontario Energy Board *Filing Requirements For Electricity Distribution Rate Applications – 2017 Edition for 2018 Rate Applications – Chapter 2 Cost of Service* July 20, 2017, p. 58

At the first reference above, it is stated that:

> 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 10th consumption percentile. The following is a description of the method that Alectra Utilities used to derive the 10th 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.

At the second reference above, it is stated that:

> Distributors must provide a description of the method they 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).

Please elaborate on the nature of the data that was used including what is meant by "active residential customers who consumed electricity at the location."

PRZ-Staff-2
Ref: E2/T3/S8, p.1 and Ontario Energy Board *Filing Requirements For Electricity Distribution Rate Applications – 2017 Edition for 2018 Rate Applications – Chapter 2 Cost of Service* July 20, 2017, p. 22

At the first reference above, it is stated that:

> Alectra Utilities is requesting to collect renewable generation funding of $266,079 in 2018 or $22,173 per month from all provincial ratepayers for the PowerStream RZ, as identified in Table 85 below:"

At the second reference above, it is stated that:

> On March 22, 2017, the Ontario government enacted the Burden Reduction Act, which amended the OEB Act, Subsection 79.1 (1) by striking out “shall provide” and substituting “may provide” in relation to the OEB providing rate protection related to costs to make an eligible investment for the purpose of connecting or enabling the connection of a qualifying generation facility. In conjunction with this change, the request for rate protection will be subject to the materiality threshold in Section 2.0.8.

Please state whether or not the above modification to Chapter 2 of the Filing Requirements, which was released after Alectra had filed its application would have any impact on the claim being made by Alectra at the first reference. If the modification would have no impact, please state why not. If it would have an impact, please state what this impact would be.

PRZ-Staff-3

<u>Ref: E2/T3/S10, p.19 Table 103 and Ontario Energy Board *Decision and Order EB-2015-0003 PowerStream Inc.* August 4, 2016, p. 3 and pp.11-12</u>

At the first reference above, the eligible capital projects for which the PowerStream RZ is seeking approval are listed and it is noted that this list was determined after the adjustment for customer preferences as discussed earlier in the evidence.

At the second reference above, which is the OEB’s Decision on PowerStream’s 2016 to 2020 rate application, the OEB expresses the concern that PowerStream

> …has also not demonstrated sufficiently that its proposed increased capital investment levels will bring value to its customers and has not engaged customers in a way that provides useful input into the development of its business plans.

At the third reference above, which is also the same OEB Decision, similar concerns are expressed by the OEB:

> The OEB does not consider that PowerStream has provided sufficient evidence of what its capital investment will accomplish in terms of outcomes for customers, and why they are appropriate, to justify approving its capital investment beyond 2017…
>
> … PowerStream has not provided evidence that it took advantage of the opportunities it did have to obtain customer views on the specifics of its proposals before these proposals were decided on…Consequently, PowerStream has not provided adequate evidence of “balancing its customer concerns with the costs and reliability” as expected under the RRFE. Customer engagement should clearly articulate the value proposition of a proposal in real terms so that customers can give informed feedback on the proposal before a distributor decides whether to proceed with the proposal.

Please discuss the changes that Alectra has made in preparing the present application for the PowerStream RZ to deal with the OEB concerns noted above.

PRZ-Staff-4

<u>Ref: E2/T3/S10, p.13, Table 98</u>

At the above reference, the bill impacts for incremental capital presented to customers are shown. This table is reproduced below:

Monthly Bill Impacts ($)	Capital Expenditures $MM	Residential (750kWh)	Rate Class GS<50 (2000 kWh)	GS>50
System Access	$11.2	$0.11	$0.28	$4.76
System Service	$5.2	$0.05	$0.13	$2.18
System Renewal	$10.2	$0.10	$0.26	$4.32
Total	**$26.6**	**$0.26**	**$0.67**	**$11.26**

Please state whether any information on an individual project basis, rather than by project category was presented to customers. If any such information was presented, please provide it. If not, please explain why not.

PRZ-Staff-5
Ref: E2/T3/S10, p.14

At the above reference, the following statement is made:

> Further, for system service and system renewal projects, customers were asked which capital investment approach they would prefer Alectra Utilities to take in 2018 for the PowerStream RZ: (i) system reliability is maintained (correlates with bill impacts identified in Table 98 above); (ii) system reliability eventually declines, calculated at 50% of the bill impacts identified in Table 98 above; and (iii) system reliability significantly declines.

a) Please state how the relationship between "system reliability eventually declines" and the referenced 50% bill impacts was determined and what time frame, if any, was meant by "eventually" and whether any definition of "declines" was established.
b) Please state what is meant by "system reliability significantly declines," specifically discussing the meaning of "significantly" and why there was no bill impact provided for this scenario.

PRZ-Staff-6
Ref: E2/T3/S10, p.15

At the above reference, the following statement is made:

> Based on feedback from customers, as provided in the Innovative Report, PowerStream revised its 2018 capital forecast from $109,773,500 to $108,315,568; and its ICM request from $26,594,248 to $25,136,316. No revision was made to the 2018 forecast or incremental capital funding request for System Service projects. The system renewal forecast and incremental capital funding request for 2018 was reduced by $1,457,932, which represents the removal of the Rear Lot Supply Remediation project at Queen/Greenway.

a) Please provide a detailed explanation as to how, based on feedback from its customers, PowerStream RZ made the above revision to its ICM request, specifically discussing any interactions with its customers in making this determination and how the extent of customer support for the incremental capital funding impacted the magnitude of the cut.

b) Please discuss the extent to which the customers affected by the removal of the Rear Lot Supply Remediation project at Queen/Greenway were consulted on this revision.

PRZ-Staff-7

Ref: E2/T3/S10, p.19 Table 103 and EB-2015-0003 PowerStream Inc. *Rate Proposal* E G/T2 February 24, 2015

At the first reference above, the eligible capital projects for which the PowerStream RZ is seeking approval are listed. This table is reproduced below:

Project Description	Capital Expenditures $
Road Authority YRRT Yonge St	$11,243,530
System Access	**$11,243,530**
Station Switchgear Replacement (ACA) 8th Line MS323	$1,394,991
Rear Lot Supply Remediation - Royal Orchard - North	$1,681,034
Cable Replacement – (M49) - Steeles and Fairway Heights	$1,842,953
Cable Replacement – (V08) - Steeles Ave and New Westminster	$2,637,046
Planned Circuit Breaker Replacement - Richmond Hill TS#1	$1,186,729
System Renewal	**$8,742,753**
Rebuild 27.6 kV pole line on Warden Ave into 4 ccts from 16th Ave to Major Mack	$1,372,976
Mill Street MS835 TX Upgrade - Tottenham	$1,298,572
Build double ccts 27.6kV pole line on 19th Ave between Leslie St and Bayview Ave	$1,202,306
Double Circuit existing 23M21 Circuit from Bayfield & Livingstone to Little Lake MS.	$1,276,180
System Service	**$5,150,033**
Total PowerStream Rate Zone Incremental Capital Funding	**$25,136,316**

With respect to the second reference, the Distribution System Plan filed by PowerStream in its EB-2015-0003 application (the DSP).

a) Please state which of the above projects are new projects which were not included in the DSP and for any such projects why they were not anticipated at the time the DSP was prepared.
b) For projects that were included in the original DSP, please summarize any modifications including any changes in the timing and amounts of cost recovery from the DSP to the current filing.
c) Please file the Project Summary Reports from the DSP for projects under part b
d) Please state the prioritization process that was used to determine that the projects listed in Table 103 above were the appropriate ones for PowerStream

RZ to seek incremental capital funding for in this application. Please relate this back to the process used in the EB-2015-0003 application discussing any similarities or differences in the approaches used.

PRZ-Staff-8

Ref: E2/T3/S10, p.11

At the above reference, the following is stated:

> Alectra Utilities reviewed and optimized its long-term general plant investment needs for the Power Stream RZ subsequent to the amalgamation of Horizon Utilities Corporation, Enersource Hydro Mississauga Inc. and Hydro One Brampton Networks Inc. Investments related to merger transitional costs and synergies have been excluded from the general plant expenditures in Table 95 above. Only capital expenditures related to on-going business requirements for the PowerStream RZ are included. The increase of $6.6MM from the 2017 Cost of Service Application to the 2017 Forecast is primarily due to the advancement of the upgrade to the CIS for the PowerStream RZ.

a) Please state how investments related to merger transitional costs and synergies were excluded from the general plant expenditures as described above. Please provide the amounts of such exclusions and a brief description of what these investments were.
b) Please state whether there were any similar exclusions from the other capital expenditure categories and if so what they were for and what their amounts were. If there were no such exclusions, please explain why not.
c) With respect to the $6.6 MM increase from the 2017 Cost of Service application to the 2017 forecast, please explain why it was necessary to advance the upgrade to the CIS for the PowerStream RZ given the merger.

PRZ-Staff-9

Ref: E2/T3/S10, p.19 Table 103 and Ontario Energy Board *Decision and Order EB-2015-0003 PowerStream Inc.* August 4, 2016, p. 17

At the first reference above, the eligible capital projects for which the PowerStream RZ is seeking approval are listed. These include two underground cable replacement projects, “Cable Replacement – (M49) – Steeles and Fairway Heights” and “Cable Replacement – (V08) – Steeles Ave. and New Westminster” which together total about $4.5 million of proposed incremental capital funding.

At the second reference above, which is the OEB’s Decision on PowerStream’s 2016 to 2020 rate application, the OEB expresses the following concern regarding PowerStream’s Underground Cable Replacement/Injection Program:

> The OEB agrees with OEB staff that unit costs have gone up substantially and that this increase has not been adequately explained…PowerStream should more adequately explain the reason for the significant increase in unit costs over time at its next rate setting opportunity.

Please discuss how Alectra has addressed this concern in the current application, or if not please explain why not. If this concern has not been addressed, please provide the explanation required by the OEB above.

PRZ-Staff-10

Ref: E2/T3/S10, p.19 Table 103 and Ontario Energy Board *Decision and Order EB-2015-0003 PowerStream Inc.* August 4, 2016, pp. 19-20

At the first reference above, the eligible capital projects for which the PowerStream RZ is seeking approval are listed. This includes a project "Rear Lot Supply Remediation – Royal York – North" for an amount of $1.7 million of proposed incremental capital funding.

At the second reference above, which is the OEB's Decision on PowerStream's 2016 to 2020 rate application, the OEB expresses the following concerns regarding PowerStream's Rear Lot Supply Remediation Program:

> As a result of the 2013 ice storm and the current assessment that a severe weather event is likely to occur once every 14 years rather than once every 17 years, PowerStream decided to use the most expensive option. However, PowerStream has not provided an analysis of the costs and benefits of this change. One expected component of such an analysis would have been an analysis of the contribution of the rear lot situation to the effects of the 2013 ice storm.
>
> PowerStream also did not consult with customers before deciding to make this change. It is striking that PowerStream testified it visited every affected rear lot, but did not speak to any of the owners of those lots, who would experience both a reliability impact and disruption to the use of their property.
>
> OEB staff expressed concern about the reliability of the standard unit cost that was used to arrive at the proposed program budget. In calculating its standard unit cost, PowerStream multiplied the cost of one historical job using the hybrid option by a factor of 1.47. The OEB agrees that based on the evidence available it is difficult to have confidence in PowerStream's forecast unit cost.

Please discuss how Alectra has addressed these concerns in the current application, or if not please explain why not. If these concerns have not been addressed, please explain why the OEB should approve the proposed spending for this project in the absence of this information.

PRZ-Staff-11

Ref: E2/T3/S10, p.20

At the above reference, the following statement is made:

> Each eligible capital project is a discrete project that meets or exceeds the materiality level for the PowerStream RZ. Each project is distinct, unrelated to a recurring annual capital project, and has been evaluated in the asset management and capital planning process as required in 2018.

a) For each of the three categories of System Access, System Renewal and System Service, please provide an example of a 2018 project that would be considered as related to a recurring annual capital project and a brief description of the project selected.
b) Please elaborate on what is meant by the eligible capital projects having "been evaluated in the asset management and capital planning process as required in 2018."

PRZ-Staff-12
Ref: E2/T3/S10, p.20

At the above reference, the following statement is made:

> The eligible capital projects for which the PowerStream RZ is requesting approval represent the most cost effective option for ratepayers. Analysis of options is provided in the business case for each eligible capital project in Attachment 33.

a) For each of these projects, please state how it was determined that they represented the most cost effective option for ratepayers.
b) Please provide the costing of the alternatives considered for each of the projects selected which demonstrates that the option chosen represents the most cost effective one for ratepayers.

PRZ-Staff-13
Ref: Tabs 1 and 2 of LRAMVA Work Form (Attachment 28) & 2013 COS Decision (EB-2012-0161), Settlement Agreement, Section 3.2, p. 14 of 32

At the first reference above, Alectra has applied for a debit balance of $1,699,829 in lost revenues associated with new CDM program savings between 2014 and 2015, including persisting savings from 2011 to 2013 programs in 2014, persisting savings from 2011 to 2014 programs in 2015, and carrying charges. An LRAMVA threshold of 137,099,754 kWh and 202,051 kW was used as the comparator against 2014 and 2015 actual results.

At the second reference above, which is PowerStream's 2013 Settlement Agreement, 245,751,229 kWh and 362,176 kW was approved as the CDM manual adjustment and was applied to the 2013 load forecast for the recovery of forecast CDM savings in rates.

a) Please discuss how an LRAMVA threshold of 137.1 GWh was determined from the 2013 CDM manual adjustment. Please provide calculations and/or assumptions, as appropriate.
b) Please state whether actual savings in 2011 were embedded into the 2013 load forecast.

PRZ-Staff-14
Ref: Tabs 1-a, 4 and 5 of LRAMVA Work Form (Attachment 28)

In Table X-1 of Tab 1-a, Alectra noted that it changed formulas to account for the ½ year rule for IESO reported savings.

a) Please identify the years of the LRAMVA disposition affected by the ½ year rule for IESO reported savings.
b) Please specify the cells of the LRAMVA work form that included these formula changes.
c) Please explain the appropriateness of claiming half of the IESO's reported savings, rather than the full year results provided by the IESO.
d) Please provide a table to confirm the following:
    i. Actual savings based on the IESO's annualized savings results, by year and rate class
    ii. Proposed actual savings to be claimed at half of the IESO's reported results, by year and rate class
    iii. Difference in savings (and respective dollars) that are not claimed in the disposition

PRZ-Staff-15
Ref: Tab 3 of LRAMVA Work Form (Attachment 28)

c) Please update row 14 in Table 3 to include the effective implementation dates of the approved rate orders that correspond with PowerStream's rate years. (For example, for the 2015 rate year, please insert the effective implementation date of "January 1, 2015 to December 31, 2015").
d) Based on the effective implementation dates of PowerStream's approved rates, please confirm the accuracy of the months entered in row 16 and revise as appropriate if necessary If the accuracy of the months entered is not confirmed, please explain..

PRZ-Staff-16
Ref: Tabs 4 and 5 of LRAMVA Work Form (Attachment 28)

a) Please provide a table that summarizes the allocation of program savings by year and initiative to PowerStream RZ's rate classes.

b) Please discuss how the savings were allocated to PowerStream RZ's customer classes. In particular, please discuss how the savings for Commercial and Industrial programs were allocated across multiple rate classes.

c) Please confirm accuracy of the rate class allocations for the following initiatives:
    i) Electricity Retrofit Incentive Program:

- 2011: 0.41% to GS<50 kW and 21.14% to GS>50 kW (row 102)

ii) High Performance New Construction:

- 2011: 17% to GS>50 kW (row 105)
- 2012: 17% to GS>50 kW (row 233)
- 2013: 17% to GS>50 kW (row 362)

iii) Multifamily Energy Efficiency Rebates:

- 2011: 27.10% to GS<50 kW (row 111)

PRZ-Staff-17

Ref: Tab 4 of LRAMVA Work Form (Attachment 28)

a) Please confirm that savings adjustments were applied prospectively in the work form. (For example, a savings adjustment identified in 2013 for 2012 programs was applied in 2013.)
b) Please revise the work form to apply adjustments back to the year of program implementation, as appropriate. (For example, a savings adjustment identified in 2013 for 2012 programs was applied in 2012.)
c) Please confirm that there were no adjustments to CDM savings in 2013, 2014 or 2015.

PRZ-Staff-18

Ref: Tab 4 of LRAMVA Work Form (Attachment 28)

Please discuss the rationale for claiming 12 months of demand savings for the Business Refrigeration program in 2013 and 2014.

PRZ-Staff-19

Ref: Tab 5 of LRAMVA Work Form (Attachment 28)

Please explain the appropriateness of claiming persistence of 2011 savings in 2014 and 2015.

PRZ-Staff-20

Ref: E2/T3/S9, p. 7

Please file an excel copy of PowerStream's 2014 and 2015 Final CDM Annual Report, and the 2011-2015 Persistence Savings Report issued by the IESO.

PRZ-Staff-21
Ref: E2/T3/S9, p. 7

If Alectra has made any changes to the PowerStream RZ LRAMVA work form as a result of its responses to interrogatories, please file an updated LRAMVA work form.

PRZ-Staff-22
Ref: IRM Model PRZ – Tab 3 Continuity Schedule

Please explain the following 'Principal Adjustments during 2016' in Account 1595:

Disposition and Recovery/Refund of Regulatory Balances (2010)	$7,318
Disposition and Recovery/Refund of Regulatory Balances (2011)	$135,000
Disposition and Recovery/Refund of Regulatory Balances (2012)	-$142,318
Disposition and Recovery/Refund of Regulatory Balances (2014)	-$(79,150)

PRZ-Staff-23
Ref: E2/T3/S5, p.6

Alectra is proposing to change an already approved rate rider for Global Adjustment with a sunset date of September 30, 2018, and is proposing to make changes to it.

a) What is Alectra's rationale for changing an OEB approved rate rider on PowerStream Rate Zone's tariffs before its sunset date?
b) The evidence indicates that Alectra's PRZ's GS 50 to 4999 kW interval customers are billed the actual GA rate, therefore, the GA rate rider should not have applied to them. Please explain why was the GA rate rider was applied to this customer class?
c) Is Alectra proposing two separate tariffs for > GS 50, one for interval customers, and the other for non-interval customers?
d) Was there an error when GA was disposed of in 2016 rates.
    i. If so, when did Alectra PowerStream Rate Zone discover the error?
    ii. Did Alectra PowerStream Rate Zone take all the steps required of them in such situations according to the various OEB policies/Codes?

PRZ-Staff-24

Ref: E2/T3/S5, p.7, lines 7-18, and IRM Model, Tab 7, 7A. and 7B.

Alectra had 9 new Class A customers in July 2015, and another 2 in July 2016. However, the billing adjustments have only been calculated for 2 customers transitioning from Class B to A.

In addition, PowerStream Rate Zone appears to have used the period from January 1, 2015 to June 30, 2016 in its calculations. OEB staff notes that the CBR program began effective April 1, 2015.

b) Has Alectra PowerStram Rate Zone used the consumption kWh in its calculation from April 1, 2015 to December 31, 2016?
    a. If not, please make the necessary amendments to the rate rider calculations and the billing adjustments for CBR.
c) Please provide evidence regarding the 9 customers who transitioned to Class A in 2015 with respect to their billing adjustments for 2015 consumption.
d) Please calculate billing adjustments for the customers who transitioned from Class B to A in 2015 as well as in 2016.
e) Please correct and refile the rate rider calculations as necessary.

PRZ-Staff-25

Ref: E2/T3/S5, p.9-10, lines 21-23 and Table 81

The evidence provided at the above two references is not consistent with respect to the amount to be disposed of by rate rider. Please state whether the amount to be disposed of by rate riders is ($26,300,803), or ($25,558,512). Please file any amendments as necessary.

PRZ-Staff-26

Ref: E2/T3/S6 and IRM Model PowerStream Rate Zone – Tab 3 Continuity Schedule, Account 1588

1) In booking expense journal entries for Charge Type 1142 (formerly 142), and Charge Type 148 from the IESO invoice, please state which of the following approaches is used:

a. Charge Type 1142 is booked into Account 1588. Charge Type 148 is pro-rated based on RPP/non-RPP consumption and then booked into Account 1588 and 1589, respectively
b. Charge Type 148 is booked into Account 1589. The portion of Charge Type 1142 equalling RPP-HOEP for RPP consumption is booked into Account 1588. The portion of Charge Type 1142 equalling GA RPP is credited into Account 1589.
c. Another approach. Please explain this approach in detail.

2) With regards to the Dec. 31, 2016 balance in Account 1589:
    a. Please indicate whether the items that flow into the account (i.e. revenues, expenses, CT 142) are based on estimates/accruals or actuals at year end.
    b. If there are reconciling items #1a, 1b in the GA Analysis Workform or if there are any proposed adjustments to Account 1589 in the DVA Continuity Schedule for the true up impacts, please quantify the adjustment that relate to each of the following items.
        i. Revenues (i.e. is unbilled revenues trued up)
        ii. Expenses - GA non-RPP (Charge Type 148) with respect to the quantum dollar amount and RPP/non-RPP pro-ration percentages
        iii. Credit of GA RPP (Charge Type 142) if the approach under IR 1b is used

3) With regards to the Dec. 31, 2016 balance in Account 1588:
    a. Please indicate whether the items that flow into the account (i.e. revenues, expenses, CT 142) are based on estimates/accruals or actuals at year end.
    b. If there are any proposed adjustments to Account 1588 in the DVA Continuity Schedule for the impacts of RPP settlement true up, please quantify the adjustment that relate to each of the following items.
        i. Revenues (i.e. is unbilled revenues trued up)
        ii. Expenses - Commodity (Charge Type 101)
        iii. Expenses - GA RPP (Charge Type 148) with respect to the quantum dollar amount and RPP/non-RPP pro-ration percentages
        iv. RPP Settlement (Charge Type 1142 - including any data used for determining the RPP/HOEP/RPP GA components of the charge type)

c. Please explain the debit adjustment of $811,309 shown in the column "Principal Adjustments During 2016" for Account 1588.

PRZ-Staff-27

Ref: E2/T3/S7 and Attachment 27 Accounting Order

Alectra has filed an Accounting Order for OEB's approval for the Metrolinx Crossings Remediation Project related capital expenditures. The evidence shows that the final design and identification of the specific number of crossings to be remediated have not been finalized by Metrolinx and project costs have not been developed.

a) When does Alectra PowerStream Rate Zone plan to have a business plan developed for this project, including project costs?
b) Is Alectra PowerStream planning to file an ICM for OEB's approval at a future date?
c) The Accounting Order states that Alectra Utilities proposes to apply to the OEB for any cost recovery of amounts recorded in the OEB-approved deferral accounting during the 2019 Annual Filing.
    i. Please provide details on how Alectra Utilities would be proposing to do cost recoveries (e.g. values to be used, what form would the rate rider take etc.)?
    ii. Account 1508 is a Group 2 account and is only disposed through a rebasing proceeding. Why does Alectra deem it appropriate to propose disposition of a Group 2 account in an IRM proceeding?
    iii. The costs in this proposed account are capital costs, and can only be added to the distributor's rate base at rebasing. How does Alectra propose to add the net book value to its rate base in an IRM proceeding?