G-Staff-1

Reference(s): 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.

Response:

Alectra Utilities' has provided the attached comparisons relative to the Account 1589 GA Work Form for 2016, by rate zone.

- Enersource Rate Zone

Table 1 below summarizes the attached Account 1589 GA Work Form for 2016 ("GA- WF") and provides a comparison for the actual GA variance booked.

Table 1: Actual GA Amounts Compared to GA Work Form (Enersource RZ)

Actual vs. Estimated GA Variance	**2016**
Actual GA variance	($1,033,668)
GA Workform estimated variance	$1,999,124
Difference	**($3,032,792)**
Reconciling Items:	
GA balances pertaining to Class A customers	$2,925,789
Current year RPP Settlement true up booked in subsequent year	($2,514,038)
Unresolved Difference	**($2,621,041)**
Unresolved Difference as % of Expected GA Payments to IESO	**-0.7%**

As shown in Table 1, the difference before consideration of any reconciling items is -$3,032,792. This represents a difference of (0.8%) of expected GA payments to the IESO. Enersource RZ has adjusted the difference with two reconciling items.

The first reconciling item is the deduction of GA balances related to Class A customers in the amount of $2,925,789. This difference is temporary and will be corrected in 2017.

The second reconciling item is related to the RPP settlement true-up claims, pertaining to the fourth quarter of 2016 but settled with the IESO in the first quarter of 2017 in the amount of -$2,514,038. The total unresolved difference is ($2,621,041) which represents a difference of (0.7%) of expected GA payments to the IESO.

- **Horizon Utilities Rate Zone**

Table 2 below summarizes the attached Account 1589 GA Work Form for 2016 GA- WF and comparison for the actual GA variance booked.

Table 2: Actual GA Amounts Compared to GA Work Form (Horizon Utilities RZ)

Actual vs. Estimated GA Variance	**2016**
Actual GA variance	($3,004,935)
GA Workform estimated variance	($2,113,851)
Unresolved Difference	**($891,084)**
Unresolved Difference as % of Expected GA Payments to IESO	**-0.5%**

As shown in Table 2, the total unresolved difference between the GA-WF estimate and the actual GA variance is ($891,084), which represents a difference of (0.5%) of expected GA payments to the IESO. Alectra Utilities' does not have any material reconciling items in the Horizon Utilities RZ.

- **Brampton Rate Zone**

Table 3 below summarizes the attached Account 1589 GA Work Form for 2016 GA- WF and comparison for the actual GA variance booked.

Table 3: Actual GA Amounts Compared to GA Work Form (Brampton RZ)

Actual vs. Estimated GA Variance	**2016**
Actual GA variance	$8,213
GA Workform estimated variance	($1,608,148)
Difference	**$1,616,361**
Reconciling Items:	
Prior year RPP Settlement true up booked in current year	$842,000
Current year RPP Settlement true up booked in subsequent year	($1,619,000)
Unresolved Difference	**$839,361**
Unresolved Difference as % of Expected GA Payments to IESO	**0.5%**

As shown in Table 3, the difference before consideration of any reconciling items is $1,616,361. This represents a difference of 0.9% of expected GA payments to the IESO. Alectra Utilities' has adjusted the difference with two reconciling items for the Brampton RZ. The first item is related to the RPP settlement true-up claims pertaining to the fourth quarter of 2015 but settled with the IESO in the first quarter of 2016 in the amount of $842,000. The second item is related to the RPP settlement true-up claims pertaining to the fourth quarter of 2016 but settled with the IESO in the first quarter of 2017 in the amount of -$1,619,000. The total unresolved difference is $839,361 which represents a difference of 0.5% of expected GA payments to the IESO.

- **PowerStream Rate Zone**

Table 4 below summarizes the attached Account 1589 GA Work Form for 2015 and 2016 GA-WF and comparison for the actual GA variance booked.

Table 4: Actual GA Amounts Compared to GA Work Form (PowerStream RZ)

Actual vs. Estimated GA Variance	**2016**	**2015**
Actual GA variance	($9,817,314)	$5,736,837
GA Workform estimated variance	($3,697,713)	$2,093,364
Difference	**($6,119,601)**	**$3,643,473**
Reconciling Items:		
GA balances pertaining to Class A customers	$275,915	$239,979
Less: Prior year-end unbilled to actual revenue differences	$3,462,448	($1,104,323)
Add: Current year-end unbilled to actual revenue differences	$4,970,749	($3,462,448)
Difference in published rates compared to actual IESO costs	$68,531	($92,108)
Unresolved Difference	**$2,658,042**	**($775,427)**
Unresolved Difference as % of Expected GA Payments to IESO	**0.6%**	**-0.2%**

As shown in Table 4, the difference before consideration of any reconciling items is ($6,119,601) in 2016 and $3,643,473 in 2015. Alectra Utilities' has adjusted the difference with four reconciling items for the PowerStream RZ.

The first reconciling item is the deduction of GA balances related to Class A customers. This difference is temporary and will be corrected in 2017.

The next two reconciling items are related to timing variances between unbilled GA revenue accruals and actual GA revenues in the amount of $2,658,042 for 2016 and ($755,427) in 2015.

The last reconciling item is related to small differences in calculated and actual IESO costs. The total unresolved difference is $2,658,042 in 2016 and ($775,427) in 2015 which represents a difference of 0.6% and (0.2%) of expected GA payments to the IESO, respectively.

Alectra Utilities' has revised the GA-WF to split the Class B Non-RPP into Interval metered and Non-interval metered amounts to accommodate billing practices. Non-interval metered customers are billed at the 1st estimate while Interval metered customers are billed at the actual GA rate. The GA-WF has been modified accordingly to accommodate this.

G-Staff-2

Reference(s): 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.

Response:

Alectra Utilities' has reviewed the Ontario Energy Board's IRM Rate Generator Model, issued September 8, 2017, and has updated Alectra Utilities' IRM Models for the Brampton, PowerStream and Enersource rate zones, originally filed in Exhibit 3, Tab 1, Schedule 1, Attachment 17 – IRM Model Brampton RZ, Attachment 26 – IRM Model PowerStream RZ and Attachment 39 – IRM Model Enersource RZ. No changes were required to Alectra Utilities' IRM Model for the Horizon Utilities rate zone based on the OEB's Model issued September 8, 2017. The IRM Model for the Horizon Utilities RZ was originally filed as Attachment 6 – IRM Model Horizon Utilities RZ.

Alectra Utilities' also completed the OEB's IRM Rate Generator Model, issued September 8, 2017, for the Brampton, PowerStream and Enersource rate zones. Alectra Utilities' provides a summary of the differences below, between Alectra Utilities' IRM Model and the OEB's IRM ate Generator Model for each rate zone.

Enersource Rate Zone:

The only difference identified between the OEB's IRM Rate Generator Model and the IRM Model submitted by Alectra Utilities' is the calculation of the CBR-B rate riders in Tab 6.2. Alectra Utilities' model rounds the rate riders to five decimal places. Please refer to G-Staff-4 for Alectra Utilities' proposal to dispose of the CBR-B rate riders to the fifth decimal place.

The IRM and RGM Models reflect updates based on Alectra Utilities' response to ERZ-Staff-1, ERZ-Staff-2, ERZ-Staff-3, ERZ-Staff-4, ERZ-Staff-6, and ERZ-Staff-19. Alectra Utilities' filed an updated LRAMVA work form as a result of its responses to this interrogatory.

PowerStream Rate Zone:

Alectra Utilities' IRM Model for the PowerStream RZ contains Tab 6C. 2016 GA Rate Rider Update. This tab calculates adjustments to the current Board-Approved (2016 CIR EB-2015-0003) GA rate rider. PowerStream bills Class B non-RPP interval billed customers at the actual monthly GA rate (no GA variance) and non-interval customers at the first estimate rate. PowerStream is proposing to bill Class B non-RPP interval billed customers at the 1st Estimate GA rate. This proposal results in the termination of the 2017 Board-Approved GA rate rider effective December 31, 2017 and the introduction of the proposed 2018 GA rate rider (2016). These changes have been incorporated in Alectra Utilities' IRM Model. The OEB's Rate Generator Model has the 2017 Board-Approved GA rate riders, as well as the proposed 2018 GA rate rider (2016) effective January 1, 2018, causing differences in the bill impacts.

The IRM and RGM Models reflect updates based on Alectra Utilities' response to PRZ-Staff-24, as well as PRZ-Staff-21. Alectra Utilities files an updated LRAMVA work form as a result of its responses to this interrogatory.

Brampton Rate Zone:

Alectra Utilities' completed the OEB's IRM Rate Generator Model, issued September 8, 2017, as well as the Alectra Utilities IRM Model for Brampton rate zone. There are no differences in the models' outcomes.

Alectra Utilities' IRM Models are filed as G-Staff-2_Attach 1_IRM Model Brampton RZ; G-Staff-2_Attach 2_IRM Model PowerStream RZ; and G-Staff-2_Attach 3_IRM Model Enersource RZ.

The IRM Rate Generator Models are filed as G-Staff-2_Attach 1_IRM RGM Brampton RZ; G-Staff-2_Attach 2_IRM RGM PowerStream RZ; and G-Staff-2_Attach 3_IRM RGM Enersource RZ.

G-Staff-3

Reference(s): 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)

Preamble:

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.

Response:

Alectra Utilities' provided a description of the actions that it would take in the event that the Board does not approve the ICM requests for the Brampton, PowerStream and Enersource rate zones in Attachments 21, 33 and 47. The specific page references in Attachments 21, 33 and 47 for each of the ICM projects are listed below:

Brampton Rate Zone	Reference
Pleasant Transformer Station CCRA True-Up	Pg. 5 of Attachment 21

PowerStream Rate Zone	Reference
Road Authority YRRT Yonge St	Pg. 9 of Attachment 33
Station Switchgear Replacement (ACA) 8th Line MS323	Pg. 15 of Attachment 33
Rear Lot Supply Remediation - Royal Orchard - North	Pg. 26 of Attachment 33
Cable Replacement – (M49) - Steeles and Fairway Heights	Pg. 33 of Attachment 33
Cable Replacement – (V08) - Steeles Ave and New Westminster	Pg. 38 of Attachment 33
Planned Circuit Breaker Replacement - Richmond Hill TS#1	Pg. 43 of Attachment 33
Rebuild 27.6 kV pole line on Warden Ave into 4 ccts from 16th Ave to Major Mack	Pg. 52 of Attachment 33
Mill Street MS835 TX Upgrade - Tottenham	Pg. 63 of Attachment 33
Build double ccts 27.6kV pole line on 19th Ave between Leslie St and Bayview Ave	Pg. 68 of Attachment 33
Double Circuit existing 23M21 Circuit from Bayfield & Livingstone to Little Lake MS.	Pg. 75 of Attachment 33

Enersource Rate Zone	Reference
Roads - QEW - Evans to Cawthra	Pg. 4 of Attachment 47
OH Rebuild - Lake/John	Pg. 50 of Attachment 47
OH Rebuild - Church	Pg. 58 of Attachment 47
Subdivision Rebuild - Glen Erin & Montevideo - Section 1	Pg. 10 of Attachment 47
Credit Woodlands Crt/Wiltshire	Pg. 23 of Attachment 47
Tenth Line Main Feeder	Pg. 29 of Attachment 47
Folkway & Erin Mills Main Feeder	Pg. 35 of Attachment 47
Glen Erin & Battleford	Pg. 16 of Attachment 47
City Centre Drive Cable Renewal	Pg. 43 of Attachment 47
Leaking Transformer Replacement Project	Pg. 68 of Attachment 47
Substation - York MS	Pg. 75 of Attachment 47

Alectra Utilities’F presented ICM projects net of customer contributions for the Enersource and PowerStream rate zones for the System Access Roads projects. There are no revenue offsets applicable to the Pleasant TS CCRA True-Up for the Brampton RZ. The following two projects were presented net of customer contributions:

Ref: Attachment 33, page 10 – ICM Business Cases PowerStream RZ

Project Description	Gross Capex	Customer Contribution	Net Capex
Road Authority YRRT Yonge St	25,414,066	14,170,536	$11,243,530
System Access	**$25,414,066**	**$14,170,536**	**$11,243,530**
Station Switchgear Replacement (ACA) 8th Line MS323	$1,394,991	$0	$1,394,991
Rear Lot Supply Remediation - Royal Orchard - North	$1,681,034	$0	$1,681,034
Cable Replacement – (M49) - Steeles and Fairway Heights	$1,842,953	$0	$1,842,953
Cable Replacement – (V08) - Steeles Ave and New Westminster	$2,637,046	$0	$2,637,046
Planned Circuit Breaker Replacement - Richmond Hill TS#1	$1,186,729	$0	$1,186,729
System Renewal	**$8,742,753**	**$0**	**$8,742,753**
Rebuild 27.6 kV pole line on Warden Ave into 4 ccts from 16th Ave to Major Mack	$1,372,976	$0	$1,372,976
Mill Street MS835 TX Upgrade - Tottenham	$1,298,572	$0	$1,298,572
Build double ccts 27.6kV pole line on 19th Ave between Leslie St and Bayview Ave	$1,202,306	$0	$1,202,306
Double Circuit existing 23M21 Circuit from Bayfield & Livingstone to Little Lake MS.	$1,276,180	$0	$1,276,180
System Service	**$5,150,033**	**$0**	**$5,150,033**
Total PowerStream Rate Zone Incremental Capital Funding	**$37,231,401**	**$12,095,085**	**$25,136,316**

Ref: E2/T4/S11 pg. 34 identifies the capital contribution for the QEW – Evans to Cawthra Road Project.

1

2

Enersource Rate Zone - ICM Projects	Gross Capex	Customer Contribution	Net Capex
Roads - QEW - Evans to Cawthra	$1,617,775	$323,555	$1,294,220
System Access	**$1,617,775**	**$323,555**	**$1,294,220**
OH Rebuild - Lake/John	$927,370	$0	$927,370
OH Rebuild - Church	$1,020,107	$0	$1,020,107
Subdivision Rebuild - Glen Erin & Montevideo - Section 1	$1,961,142	$0	$1,961,142
Credit Woodlands Crt/Wiltshire	$1,548,270	$0	$1,548,270
Tenth Line Main Feeder	$1,135,398	$0	$1,135,398
Folkway & Erin Mills Main Feeder	$1,032,180	$0	$1,032,180
Glen Erin & Battleford	$2,064,360	$0	$2,064,360
City Centre Drive Cable Renewal	$1,548,270	$0	$1,548,270
Leaking Transformer Replacement Project	$8,447,243	$0	$8,447,243
System Renewal	**$19,684,339**	**$0**	**$19,684,339**
Substation - York MS	$3,268,463	$0	$3,268,463
System Service	**$3,268,463**	**$0**	**$3,268,463**
Total Enersource Rate Zone Incremental Capital Funding	**$24,570,577**	**$323,555**	**$24,247,022**

3

G-Staff-4

Reference(s): 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.

Response:

a) Yes, Alectra Utilities' billed rate riders to customers to the 5th decimal place in the past. Specifically, the Low Voltage Service Rate, as approved in EB-2016-0077, is a rider to the 5th decimal place.

b) Yes, Alectra Utilities' billing systems in the Enersource, Horizon and PowerStream rate zones have the ability to bill to 5 decimal places. Brampton's billing system is limited to bill to 4 decimal places.

c) Appendix B of *Chapter 3 of the Filing Requirements for Electricity Distribution Rate Applications* identifies that in the event where the calculation of any rate rider results in a volumetric rate rider that rounds to zero at five significant digits, the entire OEB-approved amount for recovery or refund will typically be recorded in a USoA account 1595 for disposition in a future rate proceeding. Since the allocated Account 1580 sub-account CBR class B amount does not produce a rate rider to the fourth decimal place in few rate classes, the CBR class B rate riders for these classes are overwritten to zero and their respective OEB-approved CBR class B amounts is required to be transferred into Account 1595 for disposition at a later date. This will create an inter-generational issue for a disposition at a later date, since the entire balance in Account 1595 will be allocated across all rate classes, including those where the CBR disposition already took place. Given the above-noted issue, Alectra Utilities proposes to implement the CBR class B rate riders for the Enersource and Horizon Utilities Rate Zones rounded to the fifth decimal place to allow it to more accurately recover the claim allocated to these rate classes and to eliminate this inter-generational issue.

Tables 1 and 2 below show the impact on an average customer bill impact if the rate rider was rounded to four decimal places for each affected rate zone, as compared to the proposed rate riders to five decimal places. This analysis is not performed for the Brampton RZ, because Brampton's billing system does not have the ability to bill to the 5th decimal place.

Table 1: Enersource RZ Bill Impacts at Four Decimal Places

	Unit	Total CBR Class B $ allocated to Current Class B Customers	Metered Consumption for Current Class B Customers (Total Consumption LESS WMP, Class A and Transition Customers' Consumption)		CBR Class B Rate Rider	
			kWh	kW	to 5th Decimal (A)	to 4th Decimal (B)
RESIDENTIAL SERVICE CLASSIFICATION	kWh	($69,676)	1,532,961,312	0	-$0.00005	$0.0000
GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION	kWh	($30,243)	665,390,670	0	-$0.00005	$0.0000
GENERAL SERVICE 50 TO 499 kW SERVICE CLASSIFICATION	kW	($95,211)	2,094,754,135	6,011,343	-$0.01584	-$0.0158
GENERAL SERVICE 500 TO 4,999 kW SERVICE CLASSIFICATION	kW	($82,626)	1,817,869,707	4,170,070	-$0.01981	-$0.0198
LARGE USE SERVICE CLASSIFICATION	kW	$0	0	(0)	$0.00000	$0.0000
STANDBY DISTRIBUTION SERVICE CLASSIFICATION	kW	$0	0	0	$0.00000	$0.0000
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	($511)	11,246,374	0	-$0.00005	$0.0000
STREET LIGHTING SERVICE CLASSIFICATION	kW	($746)	16,413,628	45,704	-$0.01632	-$0.0163
		($279,013)	6,138,635,826	10,227,117		

	Unit	Typical Consumption/ Demand (monthly)	Difference in Rate (B) - (A)	Monthly Impact	Total Bill	Impact on AVG Bill
RESIDENTIAL SERVICE CLASSIFICATION	kWh	750	$0.00005	$0.04	$ 108.46	0.03%
GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION	kWh	2,000	$0.00005	$0.10	$ 306.77	0.03%
GENERAL SERVICE 50 TO 499 kW SERVICE CLASSIFICATION	kW	230	$0.00004	$0.01	$ 16,291.14	0.00%
GENERAL SERVICE 500 TO 4,999 kW SERVICE CLASSIFICATION	kW	2,250	$0.00001	$0.02	$ 74,832.50	0.00%
LARGE USE SERVICE CLASSIFICATION	kW	5,000	$0.00000	$0.00		
STANDBY DISTRIBUTION SERVICE CLASSIFICATION	kW		$0.00000	$0.00		
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	300	$0.00005	$0.02	$ 49.89	0.03%
STREET LIGHTING SERVICE CLASSIFICATION	kW	0.1	$0.00002	$0.00	$ 4.79	0.00%

Table 2: Horizon Utilities RZ at Four Decimal Places

	Unit	Total CBR Class B $ allocated to Current Class B Customers	Metered Consumption for Current Class B Customers (Total Consumption LESS WMP, Class A and Transition Customers' Consumption)		CBR Class B Rate Rider	
			kWh	kW	to 5th Decimal (A)	to 4th Decimal (B)
RESIDENTIAL SERVICE CLASSIFICATION	kWh	($78,725)	1,647,803,823	0	-$0.00005	$0.0000
GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION	kWh	($28,434)	595,148,676	0	-$0.00005	$0.0000
GENERAL SERVICE GREATER THAN 50 kW SERVICE CLASSIFICATION	kW	($76,514)	1,601,523,733	4,445,804	-$0.01721	-$0.0172
LARGE USE SERVICE CLASSIFICATION	kW	($1,213)	25,387,689	46,692	-$0.02598	-$0.0260
LARGE USE SERVICE WITH DEDICATED ASSETS CLASSIFICATION	kW	$0	0	0		
STANDBY DISTRIBUTION SERVICE CLASSIFICATION	kW	$0	0	0		
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	($553)	11,571,072	0	-$0.00005	$0.0000
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	($21)	438,985	1,213	-$0.01728	-$0.0173
STREET LIGHTING SERVICE CLASSIFICATION	kW	($1,522)	31,864,628	88,666	-$0.01717	-$0.0172
		($186,982)	3,913,738,606	4,582,376		

	Unit	Typical Consumption/ Demand (monthly)	Difference in Rate (B) - (A)	Monthly Impact	Total Bill	Impact on AVG Bill
RESIDENTIAL SERVICE CLASSIFICATION	kWh	750	$0.00005	$0.04	$ 109.65	0.03%
GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION	kWh	2,000	$0.00005	$0.10	$ 293.63	0.03%
GENERAL SERVICE GREATER THAN 50 kW SERVICE CLASSIFICATION	kW	250	$0.00001	$0.00	$ 17,245.45	0.00%
LARGE USE SERVICE CLASSIFICATION	kW	5,000	-$0.00002	($0.10)	$ 403,864.46	0.00%
LARGE USE SERVICE WITH DEDICATED ASSETS CLASSIFICATION	kW	20,000	$0.00000	$0.00	$ 1,488,389.82	0.00%
STANDBY DISTRIBUTION SERVICE CLASSIFICATION	kW		$0.00000	$0.00		
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	250	$0.00005	$0.01	$ 40.76	0.03%
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	0.3	-$0.00002	($0.00)	$ 26.12	0.00%
STREET LIGHTING SERVICE CLASSIFICATION	kW	0.1	-$0.00003	($0.00)	$ 9.00	0.00%

BRZ-Staff-1

Reference(s): 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

Response:

a) Alectra Utilities' predecessor, Hydro One Brampton, proposed changes to its Embedded Distributor Class as part of its 2015 Cost of Service Application (EB-2014-0083), filed April 25, 2014. In Exhibit 7, Tab 1, Schedule 3, pages 3 and 4 of Hydro One Brampton's 2015 COS Application, Hydro One Brampton proposed a 100% fixed monthly distribution rate for this class with no volumetric rate for this class. Hydro One Brampton indicated that "*the peak demand load values fluctuate significantly for this class and can be anywhere between zero and more than 5.0 MW due to the irregular nature of the embedded distributor's capacity requirements.*"

The Ontario Energy Board ("OEB") approved Hydro One Brampton's request to make changes to the conditions in the Tariff of Rates and Charges with respect to the approach to bill the Embedded Distributor Service Classification per Exhibit 7, Tab 1, Schedule 3, pages 3 and 4 of the application as accepted by all parties to the Settlement Agreement approved by the OEB.

Further, the OEB approved Deferral and Variance Account rate riders for the Embedded Distributor Class in Hydro One Brampton's 2017 IRM Application (EB-2016-0080), based on a kWh billing determinant.

BRZ-Staff-2

Reference(s): 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.

Response:

Alectra Utilities' predecessor, Hydro One Brampton, proposed changes to its Embedded Distributor Class as part of its 2015 Cost of Service Application (EB-2014-0083), filed April 25, 2014. In Exhibit 7, Tab 1, Schedule 3, pages 3 and 4 of Hydro One Brampton's 2015 COS Application, Hydro One Brampton proposed to bill the Embedded Distributor class "*the Retail Transmission Service Rates ("RTSRs") based on the retail rates being billed to the General Service 700 to 4,999kW class, since it does not have class specific rates."* Further, Hydro One Brampton proposed a 100% monthly fixed distribution rate for this class with no volumetric rate for this class. Hydro One Brampton indicated that "*the peak demand load values fluctuate significantly for this class and can be anywhere between zero and more than 5.0MW due to the irregular nature of the embedded distributor's capacity requirements."* The Ontario Energy Board ("OEB") approved Hydro One Brampton's request to make changes to the conditions in the Tariff of Rates and Charges with respect to the approach to bill the Embedded Distributor Service Classification per Exhibit 7, Tab 1, Schedule 3, pages 3 and 4 of the application as accepted by all parties to the Settlement Agreement approved by the OEB.

a) Alectra Utilities' confirms 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) Alectra Utilities' confirms that the forecasted total revenue required from the RTSR-Network 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) Alectra Utilities' confirms that due to the significant fluctuation in peak demand for this class, Alectra Utilities' forecasts no peak demand for this customer class.

BRZ-Staff-3

Reference(s): Ex.2, Tab 2, Schedule 8, Page 2
Attachment 17, IRM Model Brampton RZ, Tab. 3 Continuity Schedule

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?

Response:

a) Alectra Utilities' records a LRAMVA accrual entry quarterly based on estimated CDM savings in the year the savings occurred for the Brampton Rate Zone. A true-up entry is recorded when the IESO Final Annual Verified Results for 2016 is published in 2017.

b) Alectra Utilities' is not seeking disposition of LRAM balances for the Brampton Rate Zone.

BRZ-Staff-4

Reference(s): Ex.2, Tab 2, Schedule 10, Page 5

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?**

Response:

a) The service period for the five year anniversary true-up Connection and Cost Recovery Agreement (CCRA) shortfall payment was May 2008 to May 2014.

b) The calculation of the $7.086 million payment amount is provided in BRZ-Staff-4_Attach 1_Pleasant TS 5 Year true-up. The payment was forecasted in the 2015 Cost of Service.

c) The payment was forecasted to be made in 2014.

d) The payment was forecasted for $ 3.653 million.

Date:	4-Aug-15
Project #	539364

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - 1st true-up

Facility Name	Pleasant TS
Description:	
Customer:	Hydro One Brampton

<----- Project year ended - annualized from In-Service Date ----->

	Month / Year	In-Service Date Jun-2 2008	Jun-2 2009	Jun-2 2010	Jun-2 2011	Jun-2 2012	Jun-2 2013 (1st true-up)	Jun-2 2014	Jun-2 2015	Jun-2 2016	Jun-2 2017	Jun-2 2018 (2nd true-up)	Jun-2 2019	Jun-2 2020	Jun-2 2021	Jun-2 2022	Jun-2 2023 (3rd true-up)	Jun-2 2024	Jun-2 2025	Jun-2 2026	Jun-2 2027	Jun-2 2028	Jun-2 2029	Jun-2 2030	Jun-2 2031	Jun-2 2032	Jun-2 2033
		0	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*	*19*	*20*	*21*	*22*	*23*	*24*	*25*
Revenue & Expense Forecast																											
Load Forecast (MW)			1.3	5.0	19.0	24.6	35.1	33.7	50.3	66.2	74.8	81.2	87.5	93.2	99.6	103.7	108.1	112.2	116.6	119.2	122.4	122.4	122.4	122.4	122.4	122.4	122.4
Load adjustments (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			1.3	5.0	19.0	24.6	35.1	33.7	50.3	66.2	74.8	81.2	87.5	93.2	99.6	103.7	108.1	112.2	116.6	119.2	122.4	122.4	122.4	122.4	122.4	122.4	122.4
Tariff Applied ($/kW/Month)			1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50
Incremental Revenue - $k			23.4	90.0	342.0	442.8	631.8	606.6	905.4	1,191.6	1,346.4	1,461.6	1,575.0	1,677.6	1,792.8	1,866.6	1,945.8	2,019.6	2,098.8	2,145.6	2,203.2	2,203.2	2,203.2	2,203.2	2,203.2	2,203.2	2,203.2
Removal Costs - $k		0.0																									
On-going OM&A Costs - $k		0.0	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)
Ontario Capital Tax and Municipal Tax - $k			(265.7)	(261.2)	(257.1)	(253.3)	(249.8)	(246.6)	(243.6)	(240.9)	(238.4)	(236.1)	(233.9)	(232.0)	(230.2)	(228.5)	(227.0)	(225.6)	(224.3)	(223.1)	(222.1)	(221.1)	(220.1)	(219.3)	(218.5)	(217.8)	(217.1)
Net Revenue/(Costs) before taxes - $k		0.0	(268.3)	(197.2)	58.9	163.5	356.0	334.0	635.8	924.7	1,082.0	1,199.5	1,315.1	1,419.6	1,536.6	1,612.1	1,653.8	1,729.0	1,809.5	1,857.5	1,916.1	1,917.1	1,918.1	1,918.9	1,919.7	1,920.4	1,921.1
Income Taxes - $k		0.0	381.5	621.2	487.4	410.1	305.4	278.6	141.4	11.2	(70.7)	(136.5)	(199.6)	(257.0)	(317.2)	(361.2)	(392.1)	(433.3)	(475.2)	(504.7)	(536.9)	(547.9)	(558.1)	(567.4)	(576.0)	(584.0)	(591.2)
Operating Cash Flow (after taxes) - $k		0.0	113.2	424.0	546.3	573.6	661.4	612.7	777.2	935.9	1,011.3	1,063.1	1,115.5	1,162.6	1,219.5	1,250.9	1,261.7	1,295.7	1,334.2	1,352.8	1,379.3	1,369.2	1,360.0	1,351.5	1,343.7	1,336.5	1,329.8
	Cumulative PV @ 5.93%																										
PV Operating Cash Flow (after taxes) - $k (A)	12,005.1	**0.0**	**110.0**	**388.9**	**473.0**	**468.9**	**510.3**	**446.3**	**534.5**	**607.6**	**619.8**	**615.0**	**609.2**	**599.4**	**593.5**	**574.7**	**547.3**	**530.5**	**515.8**	**493.7**	**475.2**	**445.3**	**417.5**	**391.7**	**367.6**	**345.2**	**324.2**
Capital Expenditures - $k																											
Capital cost before overheads & AFUDC - $k		(20,541.6)																									
- Overheads - $k		0.0																									
- AFUDC - $k		0.0																									
Total upfront capital expenditures - $		**(20,541.6)**																									
On-going capital expenditures - $k			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures - $		0.0																									
Total capital expenditures - $k		**(20,541.6)**																									
Capital Contributions - $k																											
Previous capital contribution/(credit		0.0	0.0	0.0	0.0	0.0																					
Current capital contribution/(credit							0.0																				
PV of annual capital contributior		0.0	0.0	0.0	0.0	0.0	0.0																				
Total PV		**0.0**																									
PV Proceeds on disposal of assets - $k		**0.0**																									
PV CCA Residual Tax Shield - $k		**126.9**																									
PV Working Capital - $k		**(0.9)**																									
PV Capital (after taxes) - $k (B)	(20,415.6)	(20,415.6)																									
Cumulative PV Cash Flow (after taxes) - $k (A) + (B)	(8,410.4)	(20,415.6)	(20,305.6)	(19,916.7)	(19,443.7)	(18,974.8)	(18,464.5)	(18,018.2)	(17,483.7)	(16,876.2)	(16,256.4)	(15,641.3)	(15,032.1)	(14,432.7)	(13,839.1)	(13,264.4)	(12,717.1)	(12,186.6)	(11,670.8)	(11,177.1)	(10,702.0)	(10,256.7)	(9,839.2)	(9,447.5)	(9,079.9)	(8,734.7)	(8,410.4)

Discounted Cash Flow Summary

Economic Study Horizon - Years: 25

Discount Rate - % 5.93%

		Before Cont $k		After Cont $k	Impact $k
PV Incremental Revenue		15,979.8		15,979.8	
PV OM&A Costs		(486.2)		(486.2)	
PV Ontario Capital Tax and Municipal Ta		(3,178.2)		(1,734.4)	1,443.9
PV Income Taxes		(4,310.4)		(4,815.7)	(505.4)
PV CCA Tax Shield		4,127.1		2,170.2	(1,956.9)
PV Capital - Upfront	(20,541.6)		(20,541.6)		
Add: **PV Capital Contribution**	**0.0**	(20,541.6)	**9,428.8**	(11,112.8)	9,428.8
PV Capital - On-going		0.0		0.0	
PV Proceeds on disposal of asset:		0.0		0.0	
PV Working Capita		(0.9)		(0.9)	
PV Surplus / (Shortfall)		(8,410.4)		(0.0)	**8,410.4**
Profitability Index*		**0.6**		**1.0**	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Capital Contributions

	Date	PV of Cont $k	Previous Cont Payments $k	Current Cont / (Credit) $k
Initial economic evaluatior	2008	4,116.0	4,116.0	
1st true-up	2013	5,312.8		7,086.1
Total		**9,428.8**	**4,116.0**	**7,086.1**
Contribution Required (before HST)				**7,086.1**

Notes:
1) Payment from customer must include HST/GST.

Other Assumptions

Other Assumptions		Notes:
In-Service Date	2-Jun-08	
Municipal Tax	1.02%	Transmission system average
Federal Income Tax	21.00%	Federal corporate income ta
Ontario Corporation Income Ta	14.00%	Provincial corporate income ta
Working cash net lag days	13.14	As per Lead Lag study
CCA Rate for Class 47 Assets	8%	100% Class 47 assets

Calculation Time Stamp: 04-Aug-15, 11:01 AM

BRZ-Staff-5

Reference(s): Ex.2, Tab 2, Schedule 10, Pages 4-6

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?

Response:

a) The calculation of the $6.80 million payment is provided as BRZ-Staff-5_Attach 1_Pleasant TS 10 Year true-up.

b) The initial annual forecasted load used in setting the initial capital contribution at the time Pleasant TS was build.

Table 1: Initial annual forecasted load used in setting the initial capital contribution at the time Pleasant TS was build.

Annual Period Ending On:	'New' 27.6kV Load at Pleasant TS [T7/T8] [MW]	Avg. monthly unused capacity at existing facilities [MW]	'New' load for CCRA true-up [MW]
1st Anniversary of In Service Date	26.0	0	26.0
2nd Anniversary of In Service Date	42.6	0	42.6
3rd Anniversary of In Service Date	56.4	0	56.4
4th Anniversary of In Service Date	68.9	0	68.9
5th Anniversary of In Service Date	80.5	0	80.5
6th Anniversary of In Service Date	92.4	0	92.4
7th Anniversary of In Service Date	104.7	0	104.7
8th Anniversary of In Service Date	116.2	0	116.2
9th Anniversary of In Service Date	122.4	0	122.4
10th Anniversary of In Service Date	122.4	0	122.4
11th Anniversary of In Service Date	122.4	0	122.4

12th Anniversary of In Service Date	122.4	0	122.4
13th Anniversary of In Service Date	122.4	0	122.4
14th Anniversary of In Service Date	122.4	0	122.4
15th Anniversary of In Service Date	122.4	0	122.4
16th Anniversary of In Service Date	122.4	0	122.4
17th Anniversary of In Service Date	122.4	0	122.4
18th Anniversary of In Service Date	122.4	0	122.4
19th Anniversary of In Service Date	122.4	0	122.4
20th Anniversary of In Service Date	122.4	0	122.4
21st Anniversary of In Service Date	122.4	0	122.4
22nd Anniversary of In Service Date	122.4	0	122.4
23rd Anniversary of In Service Date	122.4	0	122.4
24th Anniversary of In Service Date	122.4	0	122.4
25th Anniversary of In Service Date	122.4	0	122.4

The annual actual load which materialized.

Table 2: Actual load which materialized at Pleasant TS

Annual Period Ending On:	'New' 27.6kV Load at Pleasant TS [T7/T8] [MW]	Avg. monthly unused capacity at existing facilities [MW]	'New' load for CCRA true-up [MW]
1st Anniversary of In Service Date	20.9	19.6	1.3
2nd Anniversary of In Service Date	21.5	16.5	5.0
3rd Anniversary of In Service Date	33.7	14.7	19.0
4th Anniversary of In Service Date	45.5	20.9	24.6
5th Anniversary of In Service Date	52.1	17.0	35.1
6th Anniversary of In Service Date	57.7	24.0	33.7
7th Anniversary of In Service Date	61.2	30.5	30.6
8th Anniversary of In Service Date	57.9	31.2	26.8
9th Anniversary of In Service Date	61.6	28.2	33.4

c) The original capital contribution for Pleasant TS was $ 4.116 million.

d) HONI's CCRA model is a net present value model which relies on a discounted cash flow methodology which takes into consideration 25 years of future cash flows related to incremental revenues, capital costs, OM&A and taxes. It would be possible to estimate a contingent obligation every year, however it would be subject to variability based on changes in future cash flows and load forecasts.

e) Alectra adheres to the terms of the CCRA and the Transmission System Code which state that HONI is required to complete a true-up on the five, ten and if applicable, fifteen year anniversaries to settle demand forecast excesses or shortfalls. No, Hydro One Brampton has not considered estimating or setting aside funds.

Date:	21-Jun-17
Project #	539364

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - 2nd true-up

Facility Name:	Pleasant TS
Description:	
Customer:	Hydro One Brampton

		In-Service Date	<------- Project year ended - annualized from In-Service Date -------->																							
	Month	Jun-2	Jun-2	Jun-2	Jun-2	Jun-2	Jun-2	Jun-2	Jun-2	Jun-2	Jun-2	Jun-2	Jun-2	Jun-2	Jun-2	Jun-2	Jun-2	Jun-2	Jun-2	Jun-2	Jun-2	Jun-2	Jun-2	Jun-2	Jun-2	Jun-2	Jun-2
	Year	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
							1st true-up					2nd true-up					3rd true-up										
		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue & Expense Forecast																											
Load Forecast (MW)			1.3	5.0	19.0	24.6	35.1	33.7	30.6	26.8	40.3	41.1	45.6	50.1	54.0	59.0	63.4	68.8	73.4	77.5	81.0	85.9	90.6	95.1	99.4	102.4	104.8
Load adjustments (MW)			2.0	2.4	2.5	1.6	2.3	2.7	4.0	4.0	5.0	5.4	5.2	5.0	4.7	4.5	4.3	4.2	3.9	3.4	2.7	2.3	2.1	1.9	1.7	1.5	1.3
			3.3	7.4	21.5	26.2	37.5	36.4	34.7	30.8	45.3	46.5	50.9	55.1	58.7	63.5	67.7	73.0	77.3	80.8	83.7	88.2	92.8	97.0	101.1	103.9	106.2
Tariff Applied ($/kW/Month)			1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50
Incremental Revenue - $k			59.3	133.1	387.5	471.5	674.3	655.1	624.0	554.7	815.9	836.3	915.3	991.6	1,056.3	1,142.3	1,218.6	1,314.3	1,392.0	1,455.1	1,506.7	1,587.3	1,669.8	1,745.9	1,819.7	1,870.0	1,910.9
Removal Costs - $k		0.0																									
On-going OM&A Costs - $k		0.0	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(26.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)
Ontario Capital Tax and Municipal Tax - $K			(265.7)	(261.2)	(257.1)	(253.3)	(249.8)	(246.6)	(243.6)	(240.9)	(238.4)	(236.1)	(233.9)	(232.0)	(230.2)	(228.5)	(227.0)	(225.6)	(224.3)	(223.1)	(222.1)	(221.1)	(220.1)	(219.3)	(218.5)	(217.8)	(217.1)
Net Revenue/(Costs) before taxes - $k		0.0	(232.4)	(154.2)	104.4	192.3	398.5	382.5	354.4	287.9	551.5	574.2	655.4	733.6	800.1	887.8	926.6	1,023.7	1,102.6	1,167.0	1,219.6	1,301.3	1,384.7	1,461.6	1,536.2	1,587.2	1,628.8
Income Taxes - $k		0.0	368.9	606.1	471.4	400.1	290.5	261.7	239.9	234.1	115.0	82.4	31.3	(16.9)	(59.4)	(107.7)	(137.5)	(186.5)	(227.8)	(263.0)	(293.1)	(332.3)	(371.4)	(407.4)	(441.8)	(467.3)	(488.9)
Operating Cash Flow (after taxes) - $k		0.0	136.5	451.9	575.9	592.3	689.0	644.2	594.3	521.9	666.5	656.6	686.7	716.7	740.7	780.1	789.1	837.2	874.8	904.0	926.6	968.9	1,013.3	1,054.2	1,094.4	1,119.9	1,139.8
	Cumulative PV @ 5.93%																										
PV Operating Cash Flow (after taxes) - $k (A)	9,000.9	**0.0**	**132.7**	**414.5**	**498.6**	**484.2**	**531.7**	**469.3**	**408.7**	**338.8**	**408.5**	**379.9**	**375.0**	**369.5**	**360.5**	**358.4**	**342.3**	**342.8**	**338.2**	**329.9**	**319.2**	**315.1**	**311.1**	**305.5**	**299.4**	**289.2**	**277.9**
Capital Expenditures - $k																											
Capital cost before overheads & AFUDC - $k		(20,541.6)																									
- Overheads - $k		0.0																									
- AFUDC - $k		0.0																									
Total upfront capital expenditures - $k		**(20,541.6)**																									
On-going capital expenditures - $k			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures - $k		0.0																									
Total capital expenditures - $k		**(20,541.6)**																									
Capital Contributions - $k																											
Previous capital contribution/(credit)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0																
Current capital contribution/(credit)												0.0															
PV of annual capital contribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0															
Total PV		**0.0**																									
PV Proceeds on disposal of assets - $k		**0.0**																									
PV CCA Residual Tax Shield - $k		**126.9**																									
PV Working Capital - $k		**(0.9)**																									
PV Capital (after taxes) - $k (B)	**(20,415.6)**	**(20,415.6)**																									
Cumulative PV Cash Flow (after taxes) - $k (A) + (B)	**(11,414.7)**	**(20,415.6)**	**(20,282.9)**	**(19,868.4)**	**(19,369.7)**	**(18,885.6)**	**(18,353.9)**	**(17,884.6)**	**(17,476.0)**	**(17,137.1)**	**(16,728.7)**	**(16,348.8)**	**(15,973.8)**	**(15,604.2)**	**(15,243.7)**	**(14,885.3)**	**(14,543.0)**	**(14,200.2)**	**(13,862.0)**	**(13,532.2)**	**(13,213.0)**	**(12,897.9)**	**(12,586.8)**	**(12,281.3)**	**(11,981.8)**	**(11,692.6)**	**(11,414.7)**

Discounted Cash Flow Summary

Economic Study Horizon - Years:		**25**			
Discount Rate - %		**5.93%**			
		Before Cont $k		**After Cont** $k	**Impact** $k
PV Incremental Revenue		11,357.9		11,357.9	
PV OM&A Costs		(486.2)		(486.2)	
PV Ontario Capital Tax and Municipal Tax		(3,178.2)		(1,269.4)	1,908.8
PV Income Taxes		(2,692.7)		(4,085.9)	(1,393.2)
PV CCA Tax Shield		4,127.1		1,774.8	(2,352.3)
PV Capital - Upfront	(20,541.6)		(20,541.6)		
Add: PV **Capital Contribution**	**0.0**	(20,541.6)	**13,251.4**	(7,290.2)	13,251.4
PV Capital - On-going		0.0		0.0	
PV Proceeds on disposal of assets		0.0		0.0	
PV Working Capital		(0.9)		(0.9)	
PV Surplus / (Shortfall)		**(11,414.7)**		**0.0**	**11,414.7**
Profitability Index*		**0.4**		**1.0**	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Capital Contributions

	Date	PV of Cont $k	Previous Cont Payments $k	Current Cont / (Credit) $k
Initial economic evaluation	2008	4,116.0	4,116.0	
1st true-up	2013	5,312.8	7,086.1	
2nd true-up	2018	3,822.6		6,800.4
Total		**13,251.4**	**11,202.1**	**6,800.4**
Contribution Required (before HST)				**6,800.4**

Notes:
1) Payment from customer must include HST/GST.

Other Assumptions		**Notes:**
In-Service Date:	2-Jun-08	
Municipal Tax	1.02%	Transmission system average
Federal Income Tax	21.00%	Federal corporate income tax
Ontario Corporation Income Tax	14.00%	Provincial corporate income tax
Working cash net lag days	13.14	As per Lead Lag study
CCA Rate for Class 47 Assets	8%	100% Class 47 assets

Calculation Time Stamp: 21-Jun-17, 4:41 PM

BRZ-Staff-6

Reference(s): 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.

Response:

System Access investments (such as Dx Expansion) are outside the control of Alectra Utilities' and are required to meet customer service obligations in accordance with the DSC, as stated in Exhibit 2, Tab 2, Schedule 10, p.2.

Alectra Utilities' continues to experience approximately 4000 new residential connections annually in the Brampton RZ. Similar to previous years, the 2017 and 2018 investments include projects designed to provide service to new load centers driven by residential subdivision development activities occurring along the northern sector of Brampton. An example of these subdivision development activities, include the required installation of new infrastructure along Mayfield Road from Mississauga Road to Creditview Road in 2017 and along Mayfield Road from Creditview Road to Chinguacousy Road in 2018.

The Industrial /Commercial sector has seen new development in the South west service area of Brampton which requires the expansion of the Jim Yarrow Feeder along the Utility Corridor from Mississauga Road to Heritage Road in 2017 and continuing along Heritage Road in 2018 from the utility corridor north to supply a new development site for 2018. Alectra Utilities' has provided 2017 and 2018 Infrastructure Maps as BRZ-Staff-6_Attach 1_2017 & 2018 Priority Infrastructure Area Maps.

The City of Brampton is embarking on a downtown core revitalization project commencing in mid-2017. This project involves major reconstruction of Main St, northerly from Queen St., and include the replacement of sewers, watermain and full streetscaping upgrades. The City of Brampton has placed a moratorium on all roadway excavation activities after completion of the

City's infrastructure works. The City of Brampton Economic Development group has provided a plan outlining re-development projects along this section of Main St, which are expected to begin upon completion of the revitalization project. In order to ensure the ability to provide electrical service and to connect new customers, Alectra Utilities' must install new underground infrastructure with provision for services, including underground connection points via sub grade chambers and duct structures, in coordination with the revitalization project to be completed in advance of the final restoration. The estimated cost for this work in 2018 is $1.5 MM.

Diverting any of the costs for these expenditures to the CCRA payment would result in the inability to connect new customers.

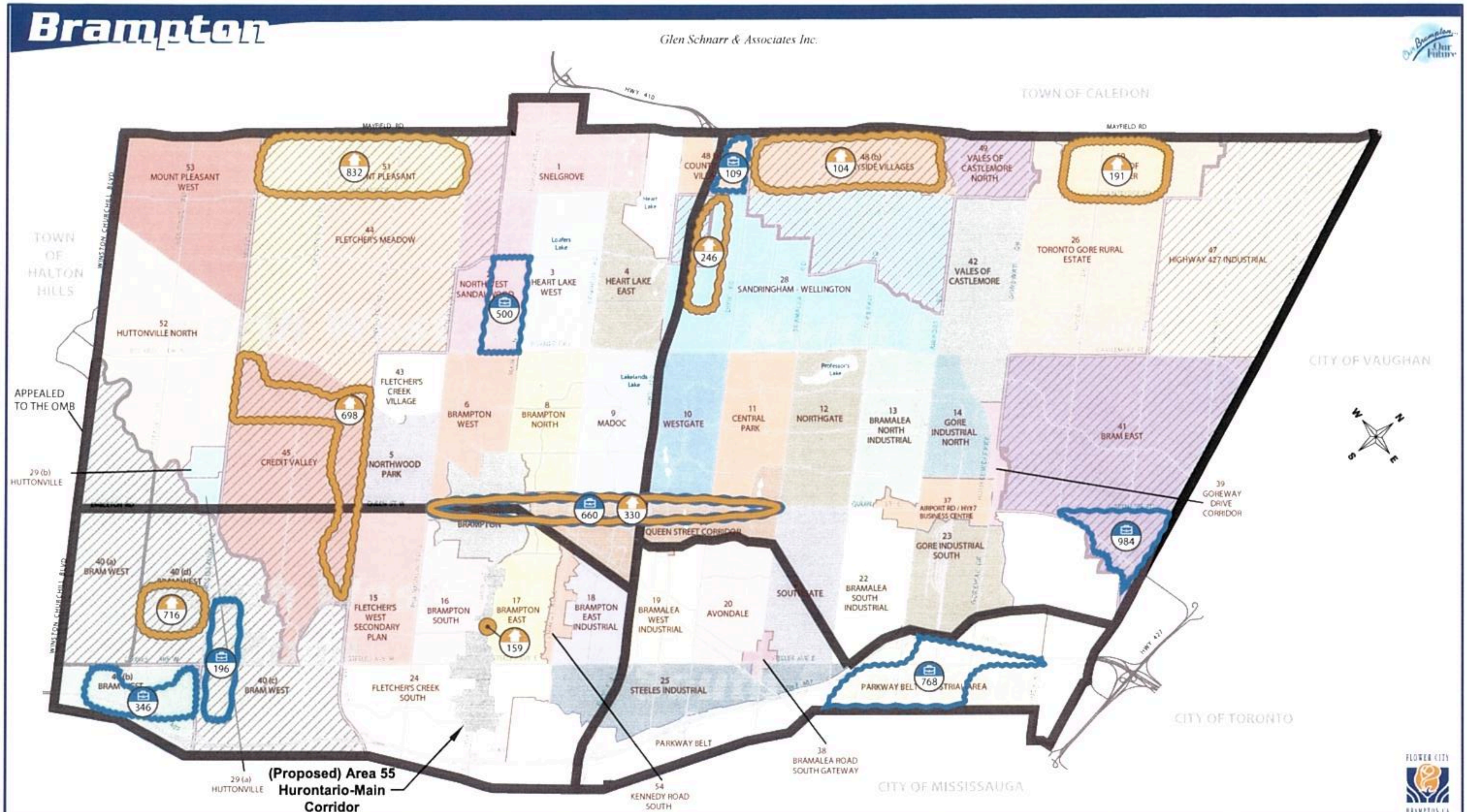


Figure 5

SUMMARY OF PRIORITY INFRASTRUCTURE AREAS FOR HOUSING AND EMPLOYMENT FORECASTS

LEGEND

Number of Dwelling Units

Number of Jobs

Year: 2017

Notes: Values are not cumulative and represent isolated growth forecast per year

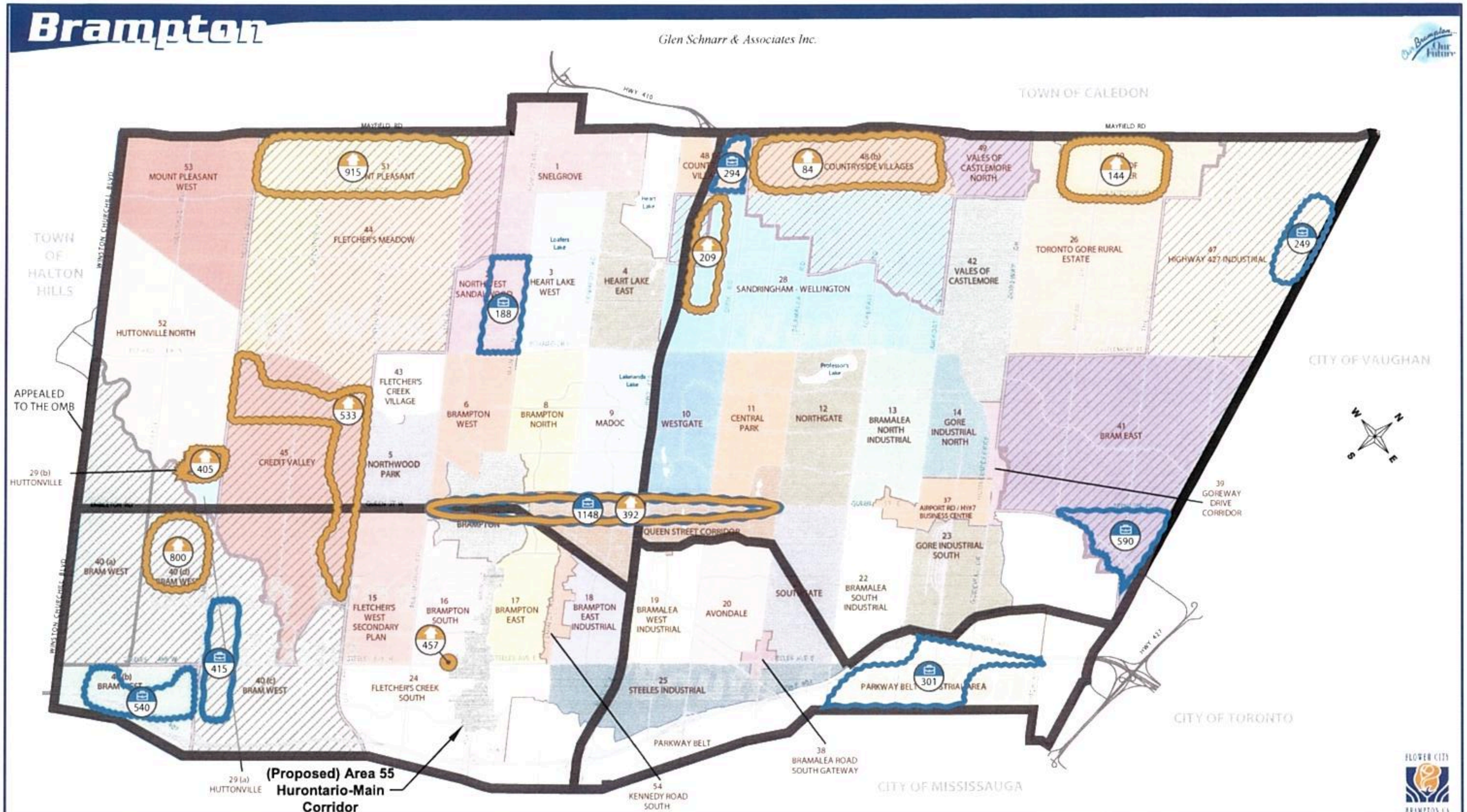


Figure 6

SUMMARY OF PRIORITY INFRASTRUCTURE AREAS FOR HOUSING AND EMPLOYMENT FORECASTS

LEGEND

- Number of Dwelling Units
- Number of Jobs

Year: 2018

Notes: Values are not cumulative and represent isolated growth forecast per year

BRZ-Staff-7

Reference(s): 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.

Response:

a) The metering investment of $5.651 million in 2015 was required to replace specific commercial 16s meters to address an identified flaw in the meter which lead to catastrophic meter failures that introduced a hazard to public and employee safety. Hydro One Brampton Networks Inc became aware of the flaw in the meter on November 26th 2014 which initiated a project to replace all impacted meters. Hydro One Brampton Networks Inc was not aware of the need to replace all the 16s meters at the time of the Cost of Service Filing in April 2014.

BRZ-Staff-8

Reference(s): 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.

Response:

a) The 4.16 kV conversion multi-year project is designed to convert the aging 4.16 kV distribution system to the present day 27.6kV standards. The project commenced in 2010. The budget in 2015 was $1.2 MM. Actual costs however were well in excess of that amount, at $3.2 MM. The increase came as a result of Hydro One Networks Brampton Inc.'s discovery that relevant asset conditions were significantly worse than had been anticipated during the planning phase. It was determined that the appropriate course of conduct was to effect full rather than partial rebuild of the distribution system in the area.

Moreover, it was determined that the wood poles supporting the system had deteriorated to a point that they were no longer suitable for the new conductor. A greater number of wood poles required replacement than originally anticipated. HOBNI also experienced higher contractor costs for construction services.

The experience in 2015 required that the remaining portion of the multi-year project be re-scoped to ensure its successful execution. The assessment, re-scoping, design and procurement work occupied much of 2016.

b) The scope of the 2018 4.16kV conversion project involves converting the customers that are presently supply by Municipal Station ("MS") 8 to 27.6kV and decommissioning the MS. Conversion addresses two important issues: i) the age and state of the existing MS-8 transformer; and ii) the potential for supply interruption given the 2015 failure of MS-1. Each is discussed below.

MS-8 is a 1970 vintage Westinghouse transformer. It now generates high levels of explosive hydrogen gas (i.e., 398 ppm in 2016). These are caused by partial discharge, which is a partial breakdown of the insulation structure between two electrodes at different potentials (e.g., High Voltage to Low Voltage windings or winding to ground). To temporarily address the potential for imminent transformer failure, loading on the transformer was reduced. The temporary reprieve, as a result of reduction of loading, was completed through the reconfiguration of the distribution system, as well as through the accelerated conversion of some customers serviced by MS-8 onto the 27.6kV system.

The transformer also gives rise to PCB related concerns. When initially installed, the transformer was filled with PCB insulating oil. Notwithstanding that the oil was replaced in the mid-1980s, current PCB levels are at 27 ppm. The transformer contains 3,750 liters of oil and has no secondary oil containment features. Failure of the primary containment feature would result in substantial environmental contamination, leading to necessary and immediate remediation efforts, the costs of which are estimated at more than $0.2MM. The scope of the 2018 4.16kV project is urgently required, in order to convert the customers onto the 27.6kV system and immediately decommission MS-8.

The alternate supply for MS-8 was originally supported by MS-1. In 2015, the MS-1 transformer failed inspection and testing and was removed from service. Its associated cable egress is no longer available for service. There is no other supply to support MS- 8 in the event of its failure. In the event of a transformer failure at MS-8, approximately 500 customers would be without supply until a new transformer could be purchased and installed resulting in an extended outage to the customers supplied from this station. The lead time alone on such a purchase is approximately 6 to 8 months.

Alectra Utilities' plans to convert all Brampton RZ customers presently supplied by the 4.16kV; a replacement transformers for MS-8 would be a stranded cost. In view of this situation, the 2018 scope of the 4.16 kV conversion was developed to include the conversion of all customers supplied from MS-8. Completion of this work will convert these customers to the present day standard 27.6kV distribution system and facilitates the removal of the now aged MS-8 transformer.

BRZ-Staff-9

Reference(s): 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?

Response:

a) The 2014-2019 Distribution System Plan for the Brampton rate zone as filed with Cost of Service application (EB-2014-0083) included investment plans of $10.122 MM ($5.065 MM expenditure in 2015 and $5.057 MM expenditure in 2016) for the implementation of an Enterprise Resource Planning (ERP) system. The original plan included a two year implementation with an in-service date in 2016. With the April 2015 announcement of the merger and subsequent acquisition of Hydro One Brampton, the ERP system implementation project was deferred in order to avoid the risk of stranding the investment. With the creation of Alectra Utilities' and subsequent acquisition of Hydro One Brampton, Alectra Utilities' began the project to consolidate the ERP systems and has completed the discovery process. As part of the transitional effort at Alectra Utilities', implementation of a consolidated ERP system forms the transitional costs borne by the Shareholders.

For year-to-date August 2017, Alectra Utilities has invested $838,340 in the implementation of a consolidated ERP system.

b) The ERP system implementation is in progress.

BRZ-Staff-10

Reference(s): 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.

Response:

Below is the completed table including Customer Group Class A non-RPP (January 1, 2016 – June 30, 2016) Class B (July 1, 2016 – December 31, 2016) customers.

Customers	DVA Rate Rider 1 [1]	DVA Rate Rider 2 [2]	CBR B Rate Rider	GA Rate Rider	GA/CBR Bill Adjustment
WMPs	x				
Class A (Jan 1, 2016 - Dec 31, 2016)	x	x			
Class B non-RPP (Jan 1, 2016 - Jun 30, 2016)/Class A (Jul 1, 2016 - Dec 31, 2016) Customers	x	x			x
Class A non-RPP (Jan 1, 2016 - Jun 30, 2016)/Class B (Jul 1, 2016 - Dec 31, 2016) Customers	x	x			x
Class B non-RPP (Jan 1, 2016 - Dec 31, 2016) Customers	x	x	x		
Class B RPP Customers	x	x	x		

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

BRZ-Staff-11

Reference(s): 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.

Response:

a) Alectra Utilities' bills the Embedded Distributor Class B Global Adjustment (“GA”) and Class B Capacity Based Recovery (“CBR”) charges in the Brampton Rate Zone. The Embedded Distributor is not billed the actual GA and CBR charges as billed by the IESO.

b) Alectra Utilities' confirms that the GA and CBR apply to the Embedded Distributor class.

c) Alectra Utilities' provides that no update is required to the evidence.

BRZ-Staff-12

Reference(s): 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.

Response:

1) In booking expense journal entries for Charge Type 1142 (formerly 142), and Charge Type 148 from the IESO invoice, Brampton RZ used approach b) above.

This approach is consistent with Brampton RZ’s Global Adjustment (“GA”) LDC Survey Results of 2016, submitted to the Ontario Energy Board (“OEB”) in March 2016 under Section III Allocation of Variances (RPP, RSVA Power and RSVA GA), Subsections RSVA Power Account 1588 and RSVA GA Account 1589, pages 11 and 12 of 17.

2 a) With regards to the balances in Account 1589 as at December 31, 2016, both the revenues and expenses recorded in Account 1589 are based on actuals at year end.

b) Brampton RZ has a reconciling amount recorded under item 1a of the GA Analysis Workform which relates to item (iii) Credit of GA RPP (Charge Type of 142), as the fourth quarter of 2015 RPP settlement true-up was booked in the first quarter of 2016. The total amount of this adjustment was a debit of $842,000.

Brampton RZ has another reconciling amount recorded under item 1b of the GA analysis Workform that has also been included as an adjustment to Account 1589 in the DVA Continuity Schedule. This adjustment relates to item (iii) Credit of GA RPP (Charge Type of 142), as the fourth quarter 2016 GA RPP settlement true-up was booked in first quarter of 2017. The total amount of this true-up was a credit of $1,619,355.

c) The credit adjustment of $1,619,355 shown in the column “Principal Adjustments During 2016” for Account 1589 represents RPP settlement true-up claims pertaining to the fourth quarter of 2016 but settled with the IESO in the first quarter of 2017. This adjustment aligns with the guidance provided by the OEB in a letter dated May 23, 2017 titled “Guidance on the Disposition of Accounts 1588 and 1589” in which the OEB states:

"The balances in distributors' RSVA Power (1588) and Global Adjustment (1589) variance accounts that are requested for disposition by distributors must reflect RPP settlement amounts pertaining to the period that is being requested for disposition. This means that RPP settlement true-up claims made with the IESO in the period subsequent to the fiscal year for which disposition is being requested must be reflected in the balances being requested for disposition."

3)

a) With regards to the balances in Account 1588 as at December 31, 2016, both the revenues and expenses recorded in Account 1588 are based on actuals at year end.

b) Brampton RZ has included an adjustment to Account 1588 in the DVA Continuity Schedule which relates to item (iv) RPP Settlement (Charge Type 1142 – including any data used for determining the RPP/HOEP/RPP GA components of the charge type), as the fourth quarter of 2016 RPP settlement true-up was booked in the first quarter of 2017. The total amount of this true-up was a debit of $803,139.

c) The debit adjustment of $803,139 shown in the column "Principal Adjustments During 2016" for Account 1588 represents RPP settlement true-up claims that pertain to the fourth quarter of 2016 but settled with the IESO in the first quarter of 2017. This adjustment aligns with the guidance provided by the OEB in a letter dated May 23, 2017 titled *"Guidance on the Disposition of Accounts 1588 and 1589".*

ERZ-Staff-1

Reference(s): 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.**

Response:

a) Alectra Utilities' confirms that per OEB's Decision EB-2013-0124 for the former Enersource Hydro, the approved principal amount for disposition is for Account1595 (2009) and not Account 1595 (2010). Alectra Utilities' also confirms the principal amount for disposition in the amount of -$2,805,249 and interest of -$192,712 for a total of -$2,997,961. Subsequent to the filing of application EB-2013-0124 and prior to the decision, additional transactions in the amount of -$1,855 were incurred changing the principal balance to $2,807,104. Enersource RZ deemed this amount to be immaterial and wrote off the balance of $1,855. This amount should have been reflected under column AL - Principal Adjustments in 2014 and not combined with the OEB-approved disposition during 2014 under column AK. Similarly, the interest balance was -$6 more than the approved balance and should have been reflected under column AQ - Interest Adjustments in 2014 and not combined with the OEB-approved disposition during 2014 under column AP.

b) The continuity schedule has been revised to reflect all of the changes mentioned in part (a and has been submitted as part of Alectra Utilities' response to G-Staff-2. Alectra Utilities' submits that the revisions made in part (a have no impact to the total Group 1 balances requested for disposition.

ERZ-Staff-2

Reference(s): 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.

Response:

a) Alectra Utilities' confirms the OEB approved principal amount for disposition in Account 1595 (2012) of -$10,153,475 and interest of -$458,332 for a total of -$10,611,807 for the Enersource Rate Zone. Alectra Utilities' notes that the balances related to Account 1595 (2012) were incorrectly presented under Account 1595 (2013). The continuity schedule has been revised to reflect this correction and has been submitted as part of Alectra Utilities' response to G-Staff-2. The approved amount would not be entered under Account 1595 (2014) as the balances approved for disposition are as of December 31, 2012 and as such should be entered under Account 1595 (2012).

b) The total OEB-approved disposition of -$10,611,807 is made up of a principal amount of -$10,153,475 as reported under column AK and an interest amount of -$458,332 as reported under column AP and as such, no change is required to the balances reported. See below the reconciliation of the balances approved in the OEB's decision EB-2013-0124 in Account 1595 (2012).

Account Name	Account Number	Principal Balance A	Interest Balance B	Total Claim C = A + B
LV variance Account	1550	$1,690,690	$41,280	$1,731,970
RSVA – Wholesale Market Service Charge	1580	-$9,704,806	-$236,108	-$9,940,914
RSVA – Retail Transmission Network Charge	1584	$1,692,260	$27,553	$1,719,813
RSVA – Retail Transmission Connection Charge	1586	$1,028,939	$10,695	$1,039,634
RSVA - Power	1588	$716,650	-$7,074	$709,575
RSVA – Global Adjustment	1589	-$2,771,959	-$101,965	-$2,873,923
Disposition and Recovery of Regulatory Balances (2009)	1595	-$2,805,249	-$192,712	-$2,997,961
Total Group 1 Excluding Account 1589 – Global Adjustment				**-$7,737,884**
Total Group 1		**-10,153,475**	**-$458,332**	**-$10,611,807**

ERZ-Staff-3

Reference(s): 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.**

Response:

a) Alectra Utilities' confirms the balances for Account 1595 (2010), (2011) and (2012) as per OEB decision EB-2015-0065 for the Enersource Rate Zone. Alectra Utilities' notes that the balances related to Account 1595 (2010), Account 1595 (2011), and Account 1595 (2012) were incorrectly presented under Account 1595 (2011), Account 1595 (2012), Account 1595 (2013), respectively. The continuity schedule has been revised to reflect this correction and has been submitted in as part of Alectra Utilities' response to G-Staff-2. In addition, the amount reported as approved for disposition under Account 1595 (2011) in the amount of \$2,113 was understated by \$941. Similarly, the interest reported as approved for disposition of -\$4,661 was overstated by \$941. The total claim approved for disposition in the amount of -\$2,549 remains the same. The continuity schedule has been revised to reflect this correction and has been submitted as part of the response to G-Staff-2. The revisions made have no impact to the total Group 1 balances requested for disposition.

b) The sum of all balances disposed is entered in Account 1595(2014) since the balances approved for disposition are as of December 31, 2014.

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.

Response:

Alectra Utilities' has corrected this error. An updated IRM Model and Rate Generator Model has been filed in G-Staff-2.

ERZ-Staff-5

Reference(s): 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.

Response:

Alectra Utilities' has included an applicable loss factor of 1.0 to ensure the Rate Generator Model accurately uses non-loss adjusted consumption and demand to calculate RTSRs for the Enersource RZ. Alectra Utilities' predecessor Enersource chose not to adjust any of the transmission service charge determinants for losses as per section 11.3.2.4, Step Three: Calculating Retail Transmission Service Rate, of the First Generation Performance Based Regulation for Electricity Distributors - Distribution Rate Handbook, issued March 29, 2001, and continues to bill customers in this manner.

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.

Response:

Alectra Utilities' has updated Tab 17 of Alectra Utilities IRM Model. Alectra Utilities' has also completed the Ontario Energy Board's Rate Generator Model, issued by the OEB on September 8, 2017. Both Models have been filed as part of Alectra Utilities' response to G-Staff-2.

ERZ-Staff-7

Reference(s): 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 1589.**

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.**

Response:

1) In booking expense journal entries for Charge Type 1142 (formerly 142), and Charge Type 148 from the IESO invoice, Enersource RZ used approach a) above.

ERZ – Staff – 7.2 Response:

2) a) With regards to the balances in Account 1589 as at December 31, 2016, the revenues and true-ups related to RPP settlements are based on estimates/accruals at year end. The expenses recorded in Account 1589 are based on actuals at year end.

b) Alectra Utilities' has a reconciling amount recorded under item 1b of the GA Analysis Workform that has also been included as an adjustment to Account 1589 in the DVA Continuity Schedule for the Enersource RZ. This adjustment relates to item (i) Revenues, as unbilled revenues were trued up based on actual consumption for the true-up period (fourth quarter of 2016) in the first quarter of 2017. The total amount of this true-up was a credit of $2,514,038.

c) The credit adjustment of $2,514,038 shown in the column "Principal Adjustments During 2016" for Account 1589 represents RPP settlement true-up claims pertaining to the fourth quarter of 2016 but settled with the IESO in the first quarter of 2017. This adjustment aligns with the guidance provided by the OEB in a letter dated May 23, 2017 titled "*Guidance on the Disposition of Accounts 1588 and 1589*" in which the OEB states:

"The balances in distributors' RSVA Power (1588) and Global Adjustment (1589) variance accounts that are requested for disposition by distributors must reflect RPP settlement amounts pertaining to the period that is being requested for disposition. This means that RPP settlement true-up claims made with the IESO in the period subsequent to the fiscal year for which disposition is being requested must be reflected in the balances being requested for disposition."

3) a) With regards to the balances in Account 1588 as at December 31, 2016, the revenues and true-ups related to RPP settlements are based on estimates/accruals at year end. The expenses recorded in Account 1588 are based on actuals at year end.

b) Alectra Utilities' included an adjustment to Account 1588 in the DVA Continuity Schedule which relates to item (i) Revenues, as unbilled revenues were trued up based on actual consumption for the true-up period (fourth quarter of 2016) in the first quarter of 2017. The total amount of this true-up was a debit of $2,500,544 for the Enersource RZ.

c) The debit adjustment of $2,500,544 shown in the column "Principal Adjustments During 2016" for Account 1588 represents RPP settlement true-up claims pertaining to the fourth quarter of 2016 but settled with the IESO in the first quarter of 2017. This adjustment aligns with the guidance provided by the OEB in a letter dated May 23, 2017 titled "*Guidance on the Disposition of Accounts 1588 and 1589*".

ERZ-Staff-8

Reference(s): E2/T4/S5, p.7, Table 118

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.

Response:

Alectra Utilities' did not have any Class A non-RPP (January 1, 2016 – June 30, 2016) Class B (July 1, 2016 – December 31, 2016) customers in the Enersource RZ. Please see completed table below:

Table 118 – Rate Riders by Customer Group – Enersource RZ

Customers	DVA Rate Rider 1 [1]	DVA Rate Rider 2 [2]	CBR B Rate Rider	GA Rate Rider	GA/CBR Bill Adjustment
WMPs	x				
Class A (Jan 1, 2016 - Dec 31, 2016)	x	x			
Class B non-RPP (Jan 1, 2016 - Jun 30, 2016)/Class A (Jul 1, 2016 - Dec 31, 2016) Customers	x	x			x
Class A non-RPP (Jan 1, 2016 - Jun 30, 2016)/Class B (Jul 1, 2016 - Dec 31, 2016) Customers	N/A	N/A	N/A	N/A	N/A
Class B non-RPP (Jan 1, 2016 - Dec 31, 2016) Customers	x	x	x	x	
Class B RPP Customers	x	x	x		

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

ERZ-Staff-9

Establishment of New Deferral and Variance Accounts
Reference(s): 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?

Response:

a) – c) Please see Alectra Utilities' response to PRZ-Staff-27.

ERZ-Staff-10

Reference(s): E2/T4/S8, p.1-3
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.

Response:

a) Alectra Utilities' confirms it is not planning to apply the rate rider to recover the direct benefit portion in 2018.

b) See below for a reconciliation between the capital amounts, OM&A and revenue requirement and the 2016 balances for Accounts 1531,1532 and 1533.

Reconciliation of Net Fixed Assets to USoA Account 1531

	2016	2015	2016 Average NFA
Account 1531 Balance	844,925	731,308	788,116
Less Carrying Charges	(28,828)	(20,388)	(24,608)
Cumulative Capital Expenditures	816,097	710,921	763,509
Less CIP	(55,659)	(68,805)	(62,232)
Cumulative Net Fixed Assets	**760,438**	**642,116**	**701,277**

The capital amount in the 2016 balance in account 1531 is comprised of cumulative capital expenditures of $816,097 and carrying charges of $28,828. This capital expenditure balance was used to calculate the 2016 average net fixed assets of $701,277 in Exhibit 3, Tab 1, Schedule 1, Attachment 41 – Renewable Generation Connection Funding Enersource RZ**.**

Reconciliation of OM&A to USoA Account 1532

	2016	2015	Change
OM&A	148,904	90,854	58,050
Amortization	178,663	121,893	56,770
Carrying Charges	6,704	3,804	2,900

USofA 1532 Balance	**334,271**	**216,551**	**117,720**

The 2016 OM&A expenditures of $117,720 is comprised of OM&A of $58,050, amortization of $56,770, and carrying charges of $2,900. Per Attachment 41, these expenditures were used in the calculation of the 2016 revenue requirement.

Reconciliation of Revenue Requirement to USoA Account 1533	**2016**	**2015**	**Change**
Cumulative Principal Balance	(320,890)	(215,880)	(105,010)
Carrying Charges	(6,689)	(3,827)	(2,862)
USofA 1533 Balance	**(327,579)**	**(219,707)**	**(107,872)**

The 2016 Renewable Generation Connection Funding Adder amount of $105,010 above reflects the OEB approved provincial funding amounts from Enersource RZ's 2016 Price Cap IR rate application (EB-2015-0065).

The cumulative 2016 Renewable Generation Connection Funding Adder amount of $320,890 above reflects the OEB approved provincial funding amounts from all of Enersource RZ's previously approved funding amounts as follows:

EB-2012-0033 approved funding adder	(64,270)
EB-2013-0124 approved funding adder	(68,640)
EB-2014-0068 approved funding adder	(82,970)
EB-2015-0065 approved funding adder	(105,010)
Total cumulative approved funding amounts	**(320,890)**

Alectra Utilities' calculated revenue requirement for renewable generation which includes actuals for 2010–2016 and forecasts for 2017–2018 for a total of $576,590 to be recovered from provincial ratepayers. Alectra Utilities' has requested approval to recover $133,384 from all provincial rate payers which is the difference between the revenue requirement (provincial portion) of $576,590 and previously approved funding of $443,206.

ERZ-Staff-11

Reference(s): 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).

Response:

Alectra Utilities' confirms that the 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). The settlement conference for this proceeding states, "The next major element in the settlement agreement had to do with the forecast, and there was agreement to remove projected CDM energy savings from the forecast. Ultimately, you know, CDM will have its impact and, of course, there is a separate process, in any event, to deal with the impact of CDM through the LRAM and SSM process. And that had an effect, an impact, of reducing rates for the purposes of this application."

ERZ-Staff-12

Reference(s): 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.

Response:

a) Please see updated Attachment 42 where row 14 in Table 3 has been updated to include the appropriate effective implementation dates of the approved rate orders that correspond with Enersource Hydro's rate years.

b) Based on the effective implementation dates of Enersource Hydro's approved rates, it is confirmed that the months entered in row 16 were appropriate.

ERZ-Staff-13

Reference(s): 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.)

Response:

a) Please find attached two tables, "Energy Savings Allocation" and "Demand Savings Allocation", in the Attachment "42 Backup-Rate Class Allocation". It summarizes the allocation of program savings by year and initiative to Enersource Hydro's rate classes.

b) The IESO performs evaluations for all of its programs, which includes examining gross energy savings from the programs and the net-to-gross ratio (NTGR). From these evaluations the IESO calculates net energy savings by initiative within a program group (residential, business, industrial and low income). Peak load savings are also calculated, and reported the same way. For initiatives implemented under the Residential and Low Income Programs, they were 100% attributed to the Residential Rate Class. For initiatives implement under the Commercial and Industrial programs that apply to more than one rate class, the savings were estimated by rate class, drawing on participant-specific information where available.

c) Certain rate class allocations do not add up to 100% as a result of the split between energy savings allocation and the demand savings allocation. For rate classes that are billed on kWh, rate class allocation related to the specific initiative are referenced from the "Energy Savings Allocation" tab where the percentage allocation is based on the energy savings. For rate classes that are billed on kW, the rate class allocations are referenced from the

"Demand Savings Allocation" tab where the percentage allocation is based on the demand savings, referencing "Attachment 42 Backup –Rate Class Allocation" Spreadsheet.

Energy Savings Allocation	Year				
Program / Rate Class	**2011**	**2012**	**2013**	**2014**	**2015**
Consumer Program- Conservation Instant Coupon Booklet	**774,254**	**54,900**	**303,563**	**1,166,247**	**2,676,622**
Residential	774,254	54,900	303,563	1,166,247	2,676,622
Consumer Program- HVAC Incentives	**3,021,824**	**2,070,448**	**2,325,314**	**2,581,153**	**2,694,954**
Residential	3,021,824	2,070,448	2,325,314	2,581,153	2,694,954
Consumer Program-Bi-Annual Retailer Event	**1,239,625**	**1,051,579**	**674,564**	**4,825,760**	**3,717,544**
Residential	1,239,625	1,051,579	674,564	4,825,760	3,717,544
Consumer Program-Appliance Retirement	**812,064**	**430,436**	**247,739**	**205,529**	**60,261**
Residential	812,064	430,436	247,739	205,529	60,261
Consumer Program-Appliance Exchange	**11,343**	**30,332**	**32,880**	**46,919**	**-**
Residential	11,343	30,332	32,880	46,919	-
Consumer Program-Residential Demand Response	**773**	**10,075**	**10,205**	**1,247**	**-**
Residential	773	10,075	10,205	1,247	-
Consumer Program-Residential New Construction	**-**	**-**	**-**	**1,304**	**-**
Residential	-	-	-	1,304	-
Home Assistance Program	**-**	**309,710**	**472,174**	**724,043**	**343,883**
Residential	-	309,710	472,174	724,043	343,883
Business Program-Retrofit	**13,777,928**	**29,178,334**	**27,383,925**	**41,820,981**	**48,104,788**
GS<50	2,562,695	3,793,183	2,573,451	4,208,152	6,712,494
General Service 50 to 499 kW	7,481,415	14,297,384	13,445,499	19,323,746	23,045,280
General Service 500 to 4999 kW	3,596,039	10,212,417	8,583,964	16,592,724	15,667,881
Large Use	137,779	875,350	2,781,010	1,696,359	2,679,133
Unmetered					-
Business Program-Direct Install Lighting	**8,607,479**	**4,906,963**	**3,914,521**	**4,679,900**	**3,360,796**
GS<50	8,607,479	4,906,963	3,914,521	4,679,900	3,360,796
Business Program-New Construction	**-**	**247,001**	**211,782**	**204,720**	**1,504,538**
GS<50	-	-	-	148,914	15,045
General Service 50 to 499 kW	-	-	87,890	11,785	75,227
General Service 500 to 4999 kW	-	247,001	123,893	-	1,414,266
Large Use	-	-	-	44,020	-
Business Program-Demand Response 3	**70,271**	**31,557**	**17,169**	**-**	**-**
GS<50	-	-	-	-	-
General Service 50 to 499 kW	35,136	15,778	8,584	-	-
General Service 500 to 4999 kW	35,136	15,778	8,584	-	-
Large Use	-	-	-	-	-
Business Program-Energy Audit	**237,584**	**1,233,104**	**775,726**	**4,177,508**	**9,340,030**
GS<50	26,134	86,317	-	798,641	1,521,828

Energy Savings Allocation	Year				
Program / Rate Class	**2011**	**2012**	**2013**	**2014**	**2015**
General Service 50 to 499 kW	52,268	774,389	136,893	2,518,792	6,690,921
General Service 500 to 4999 kW	159,181	372,397	593,203	860,075	939,401
Large Use	-	-	45,631	-	187,880
Industrial Program-Process & System Upgrades	**-**	**-**	**-**	**-**	**2,462,181**
GS<50	-	-	-	-	-
General Service 50 to 499 kW	-	-	-	-	-
General Service 500 to 4999 kW	-	-	-	-	1,158,702
Large Use	-	-	-	-	1,303,479
Industrial Program-Energy Manager	**-**	**17,296**	**12,106,402**	**3,893,879**	**4,040,546**
GS<50	-	-	-	-	-
General Service 50 to 499 kW	-	-	-	-	-
General Service 500 to 4999 kW	-	5,189	3,628,965	1,247,479	2,223,170
Large Use	-	12,107	8,477,437	2,646,400	1,817,377
Industrial Program-Retrofit	**1,994,497**	**-**	**-**	**-**	**-**
GS<50	370,976	-	-	-	-
General Service 50 to 499 kW	1,083,012	-	-	-	-
General Service 500 to 4999 kW	520,564	-	-	-	-
Large Use	19,945	-	-	-	-
Industrial Program-Demand Response 3	**189,961**	**88,449**	**416,174**	**-**	**-**
GS<50	-	-	-	-	-
General Service 50 to 499 kW	-	-	104,044	-	-
General Service 500 to 4999 kW	47,490	22,112	312,131	-	-
Large Use	142,471	66,337	-	-	-
Conservation Fund Pilot-Loblaws Pilot					**183,513**
General Service 50 to 499 kW					0
General Service 500 to 4999 kW					183,513
Conservation Fund Pilot - SEG					**6,899,972**
General Service 50 to 499 kW					2,069,992
General Service 500 to 4999 kW					4,829,980
Other-Time of Use Savings					
Residential					
Other-LDC Pilots				**184,241**	
General Service 50 to 499 kW				0	
General Service 500 to 4999 kW				184,241	
Non-Residential Province-Wide Programs-Save on Energy Audit Funding Program					**77,834**
GS<50					12,453

Energy Savings Allocation	Year				
Program / Rate Class	**2011**	**2012**	**2013**	**2014**	**2015**
General Service 50 to 499 kW					56,040
General Service 500 to 4999 kW					7,783
Large Use					1,557
Non-Residential Province-Wide Programs-Save on Energy Retrofit Program					**210,218**
GS<50					28,485
500-4999					66,954
50-499					103,280
Large Use					11,499
Non-Residential Province-Wide Programs-Save on Energy Retrofit Program - P4P					**1,731,152**
GS<50					234,571
500-4999					551,372
50-499					850,515
Large Use					94,694
Business Program- Retrofit (Streetlight project)	**-**	**-**	**5,110,764**	**-**	**-**
Streetlighting	-	-	5,110,764	-	-
Pre-2011 Programs completed in 2011-Electricity Retrofit Incentive Prog	**12,349,671**				
GS<50	2,137,304	-			
General Service 50 to 499 kW	6,668,797	-			
General Service 500 to 4999 kW	3,428,660	-			
Large Use	114,909	-			
Pre-2011 Programs completed in 2011-High Performance New Construc	**922,657**	**418,130**			
GS<50	159,680.27	-			
General Service 50 to 499 kW	498,232.92	209,065			
General Service 500 to 4999 kW	256,158.85	209,065			
Large Use	8,584.96	-			
Pre-2011 Programs completed in 2011-Multifamily Energy Efficiency Re	**314**				
GS<50	54.34				
General Service 50 to 499 kW	169.56				
General Service 500 to 4999 kW	87.18				
Large Use	2.92				
Grand Total	**44,010,247**	**40,078,315**	**54,002,903**	**64,513,432**	**87,408,832**

Energy Savings Allocation	Percentage allocation				
Program / Rate Class	**2011**	**2012**	**2013**	**2014**	**2015**
Consumer Program- Conservation Instant Coupon Booklet	**100%**	**100%**	**100%**	**100%**	**100%**
Residential	100%	100%	100%	100%	100%
Consumer Program- HVAC Incentives	**100%**	**100%**	**100%**	**100%**	**100%**
Residential	100%	100%	100%	100%	100%
Consumer Program-Bi-Annual Retailer Event	**100%**	**100%**	**100%**	**100%**	**100%**
Residential	100%	100%	100%	100%	100%
Consumer Program-Appliance Retirement	**100%**	**100%**	**100%**	**100%**	**100%**
Residential	100%	100%	100%	100%	100%
Consumer Program-Appliance Exchange	**100%**	**100%**	**100%**	**100%**	**100%**
Residential	100%	100%	100%	100%	100%
Consumer Program-Residential Demand Response	**100%**	**100%**	**100%**	**100%**	**100%**
Residential	100%	100%	100%	100%	100%
Consumer Program-Residential New Construction	**100%**	**100%**	**100%**	**100%**	**100%**
Residential	100%	100%	100%	100%	100%
Home Assistance Program	**100%**	**100%**	**100%**	**100%**	**100%**
Residential	100%	100%	100%	100%	100%
Business Program-Retrofit	**100%**	**100%**	**100%**	**100%**	**100%**
GS<50	19%	13%	9%	10%	14%
General Service 50 to 499 kW	54%	49%	49%	46%	48%
General Service 500 to 4999 kW	26%	35%	31%	40%	33%
Large Use	1%	3%	10%	4%	6%
Unmetered	0%	0%	0%	0%	0%
Business Program-Direct Install Lighting	**100%**	**100%**	**100%**	**100%**	**100%**
GS<50	100%	100%	100%	100%	100%
Business Program-New Construction		**200%**	**200%**	**100%**	**100%**
GS<50		0%	0%	73%	1%
General Service 50 to 499 kW		0%	41%	6%	5%
General Service 500 to 4999 kW		100%	59%	0%	94%
Large Use		0%	0%	22%	0%
Business Program-Demand Response 3	**100%**	**100%**	**100%**		
GS<50	0%	0%	0%		
General Service 50 to 499 kW	50%	50%	50%		
General Service 500 to 4999 kW	50%	50%	50%		
Large Use	0%	0%	0%		
Business Program-Energy Audit	**100%**	**100%**	**100%**	**100%**	**100%**
GS<50	11%	7%	0%	19%	16%

Energy Savings Allocation	Percentage allocation				
Program / Rate Class	**2011**	**2012**	**2013**	**2014**	**2015**
General Service 50 to 499 kW	22%	63%	18%	60%	72%
General Service 500 to 4999 kW	67%	30%	76%	21%	10%
Large Use	0%	0%	6%	0%	2%
Industrial Program-Process & System Upgrades					**200%**
GS<50					0%
General Service 50 to 499 kW					0%
General Service 500 to 4999 kW					47%
Large Use					53%
Industrial Program-Energy Manager	**0%**	**100%**	**100%**	**100%**	**100%**
GS<50		0%	0%	0%	0%
General Service 50 to 499 kW		0%	0%	0%	0%
General Service 500 to 4999 kW		30%	30%	32%	55%
Large Use		70%	70%	68%	45%
Industrial Program-Retrofit	**100%**				
GS<50	19%				
General Service 50 to 499 kW	54%				
General Service 500 to 4999 kW	26%				
Large Use	1%				
Industrial Program-Demand Response 3	**100%**	**100%**	**100%**		
GS<50	0%	0%	0%		
General Service 50 to 499 kW	0%	0%	25%		
General Service 500 to 4999 kW	25%	25%	75%		
Large Use	75%	75%	0%		
Conservation Fund Pilot-Loblaws Pilot					**100%**
General Service 50 to 499 kW					0%
General Service 500 to 4999 kW					100%
Conservation Fund Pilot - SEG					**100%**
General Service 50 to 499 kW					30%
General Service 500 to 4999 kW					70%
Other-Time of Use Savings					
Residential					
Other-LDC Pilots				**100%**	
General Service 50 to 499 kW					
General Service 500 to 4999 kW				100%	
Non-Residential Province-Wide Programs-Save on Energy Audit Funding					**100%**
GS<50					16%

Energy Savings Allocation	Percentage allocation				
Program / Rate Class	**2011**	**2012**	**2013**	**2014**	**2015**
General Service 50 to 499 kW					72%
General Service 500 to 4999 kW					10%
Large Use					2%
Non-Residential Province-Wide Programs-Save on Energy Retrofit Progr					**100%**
GS<50					14%
500-4999					32%
50-499					49%
Large Use					5%
Non-Residential Province-Wide Programs-Save on Energy Retrofit Progr					**100%**
GS<50					14%
500-4999					32%
50-499					49%
Large Use					5%
Business Program- Retrofit (Streetlight project)			**100%**		
Streetlighting			100%		
Pre-2011 Programs completed in 2011-Electricity Retrofit Incentive Prog	**100%**	**100%**			
GS<50	17%	0%			
General Service 50 to 499 kW	54%	50%			
General Service 500 to 4999 kW	28%	50%			
Large Use	1%	0%			
Pre-2011 Programs completed in 2011-High Performance New Construc	**100%**	**100%**			
GS<50	17%	0%			
General Service 50 to 499 kW	54%	50%			
General Service 500 to 4999 kW	28%	50%			
Large Use	1%	0%			
Pre-2011 Programs completed in 2011-Multifamily Energy Efficiency Re	**100%**	**100%**			
GS<50	17%	0%			
General Service 50 to 499 kW	54%	50%			
General Service 500 to 4999 kW	28%	50%			
Large Use	1%	0%			
Grand Total					

Demand Savings Allocation	Year				
Program/ Initiative	**2011**	**2012**	**2013**	**2014**	**2015**
Consumer Program- Conservation Instant Coupon Booklet	**48**	**9**	**20**	**87**	**173**
Residential	48	9	20	87	173
Consumer Program- HVAC Incentives	**1,668**	**1,230**	**1,357**	**1,398**	**1,412**
Residential	1,668	1,230	1,357	1,398	1,412
Consumer Program-Bi-Annual Retailer Event	**70**	**58**	**46**	**316**	**250**
Residential	70	58	46	316	250
Consumer Program-Appliance Retirement	**110**	**59**	**37**	**30**	**9**
Residential	110	59	37	30	9
Consumer Program-Appliance Exchange	**10**	**17**	**18**	**26**	**-**
Residential	10	17	18	26	-
Consumer Program-Residential Demand Response	**298**	**1,262**	**6,291**	**7,615**	**-**
Residential	298	1,262	6,291	7,615	-
Consumer Program-Residential New Construction	**-**	**-**	**-**	**-**	**-**
Residential	-	-	-	-	-
Home Assistance Program	**-**	**47**	**76**	**59**	**30**
Residential	-	47	76	59	30
Business Program- Retrofit	**2,700**	**5,304**	**5,200**	**6,002**	**7,327**
GS<50	270	212	156	360	366
General Service 50 to 499 kW	1,701	3,501	3,328	4,021	4,250
General Service 500 to 4999 kW	702	1,432	1,196	1,380	2,345
Large Use	27	159	520	240	366
Unmetered					-
Business Program-Direct Install Lighting	**3,413**	**1,344**	**1,193**	**1,348**	**810**
GS<50	3,413	1,344	1,193	1,348	810
Business Program-New Construction	**-**	**96**	**98**	**120**	**505**
GS<50	-	-	-	96	6
General Service 50 to 499 kW	-	-	21	14	24
General Service 500 to 4999 kW	-	96	76	-	475
Large Use	-	-	-	11	-
Business Program-Small Commercial Demand Response	**-**	**-**	**-**	**243**	
GS<50	-	-	-	243	
Business Program-Demand Response 3	**1,800**	**2,171**	**1,079**	**904**	**-**
GS<50	-	-	-	-	-
General Service 50 to 499 kW	900	1,086	540	452	-

Demand Savings Allocation	Year				
Program/ Initiative	**2011**	**2012**	**2013**	**2014**	**2015**
General Service 500 to 4999 kW	900	1,086	540	452	-
Large Use	-	-	-	-	-
Business Program-Energy Audit	**49**	**253**	**141**	**855**	**1,991**
GS<50	5	18	-	164	323
General Service 50 to 499 kW	11	159	25	516	1,426
General Service 500 to 4999 kW	33	76	108	176	201
Large Use	-	-	8	-	40
Industrial Program-Process & System Upgrades	**-**	**-**	**-**	**-**	**272**
GS<50	-	-	-	-	-
General Service 50 to 499 kW	-	-	-	-	-
General Service 500 to 4999 kW	-	-	-	-	128
Large Use	-	-	-	-	144
Industrial Program-Energy Manager	**-**	**3**	**1,866**	**478**	**1,232**
GS<50	-	-	-	-	-
General Service 50 to 499 kW	-	1	-	-	-
General Service 500 to 4999 kW	-	2	560	199	616
Large Use	-	-	1,306	279	616
Industrial Program-Retrofit	**422**	**-**	**-**	**-**	**-**
GS<50	76	-	-	-	-
General Service 50 to 499 kW	238	-	-	-	-
General Service 500 to 4999 kW	106	-	-	-	-
Large Use	2	-	-	-	-
Industrial Program-Demand Response 3	**3,236**	**3,670**	**17,139**	**17,243**	**-**
GS<50	-	-	-	-	-
General Service 50 to 499 kW	-	-	4,285	-	-
General Service 500 to 4999 kW	809	918	12,854	4,311	-
Large Use	2,427	2,753	-	12,933	-
Conservation Fund Pilot-Loblaws Pilot					**14**
General Service 50 to 499 kW					0
General Service 500 to 4999 kW					14
Conservation Fund Pilot - SEG					**499**
General Service 50 to 499 kW					250
General Service 500 to 4999 kW					250
Other-Time of Use Savings				**3,831**	

Demand Savings Allocation	Year				
Program/ Initiative	**2011**	**2012**	**2013**	**2014**	**2015**
Residential				3,831	
Other-LDC Pilots				**24**	
General Service 50 to 499 kW				0	
General Service 500 to 4999 kW				24	
Non-Residential Province-Wide Programs-Save on Energy Audit Funding Program					**17**
GS<50					3
General Service 50 to 499 kW					12
General Service 500 to 4999 kW					2
Large Use					0
Non-Residential Province-Wide Programs-Save on Energy Retrofit Program					**45**
GS<50					6
500-4999					14
50-499					22
Large Use					2
Non-Residential Province-Wide Programs-Save on Energy Retrofit Program - P4P					**341**
GS<50					46
500-4999					109
50-499					168
Large Use					19
Business Program- Retrofit (Streetlight project)	**-**	**-**	**-**	**-**	**-**
Streetlighting	-	-	-	-	-
Pre-2011 Programs completed in 2011-Electricity Retrofit Incentive Program	**2,148**				
GS<50	346				
General Service 50 to 499 kW	1,198				
General Service 500 to 4999 kW	595				
Large Use	10				
Pre-2011 Programs completed in 2011-High Performance New Construction	**251**	**189**			
GS<50	40	-			
General Service 50 to 499 kW	140	95			
General Service 500 to 4999 kW	70	95			
Large Use	1	-			
Grand Total	**16,223**	**15,713**	**34,561**	**40,579**	**14,927**

Demand Savings Allocation	Percentage allocation				
Program/ Initiative	**2011**	**2012**	**2013**	**2014**	**2015**
Consumer Program- Conservation Instant Coupon Booklet	**100%**	**100%**	**100%**	**100%**	**100%**
Residential	100%	100%	100%	100%	100%
Consumer Program- HVAC Incentives	**100%**	**100%**	**100%**	**100%**	**100%**
Residential	100%	100%	100%	100%	100%
Consumer Program-Bi-Annual Retailer Event	**100%**	**100%**	**100%**	**100%**	**100%**
Residential	100%	100%	100%	100%	100%
Consumer Program-Appliance Retirement	**100%**	**100%**	**100%**	**100%**	**100%**
Residential	100%	100%	100%	100%	100%
Consumer Program-Appliance Exchange	**100%**	**100%**	**100%**	**100%**	**100%**
Residential	100%	100%	100%	100%	100%
Consumer Program-Residential Demand Response	**100%**	**100%**	**100%**	**100%**	**100%**
Residential	100%	100%	100%	100%	100%
Consumer Program-Residential New Construction	**100%**	**100%**	**100%**	**100%**	**100%**
Residential	100%	100%	100%	100%	100%
Home Assistance Program	**100%**	**100%**	**100%**	**100%**	**100%**
Residential	100%	100%	100%	100%	100%
Business Program- Retrofit	**100%**	**100%**	**100%**	**100%**	**100%**
GS<50	10%	4%	3%	6%	5%
General Service 50 to 499 kW	63%	66%	64%	67%	58%
General Service 500 to 4999 kW	26%	27%	23%	23%	32%
Large Use	1%	3%	10%	4%	5%
Unmetered	0%	0%	0%	0%	0%
Business Program-Direct Install Lighting	**100%**	**100%**	**100%**	**100%**	**100%**
GS<50	100%	100%	100%	100%	100%
Business Program-New Construction		**100%**	**100%**	**100%**	
GS<50		0%	0%	80%	
General Service 50 to 499 kW		0%	22%	11%	
General Service 500 to 4999 kW		100%	78%	0%	
Large Use		0%	0%	9%	
Business Program-Small Commercial Demand Response				**100%**	
GS<50				100%	
Business Program-Demand Response 3	**100%**	**100%**	**100%**	**100%**	
GS<50	0%	0%	0%	0%	
General Service 50 to 499 kW	50%	50%	50%	50%	

Demand Savings Allocation	Percentage allocation				
Program/ Initiative	**2011**	**2012**	**2013**	**2014**	**2015**
General Service 500 to 4999 kW	50%	50%	50%	50%	
Large Use	0%	0%	0%	0%	
Business Program-Energy Audit	**100%**	**100%**	**100%**	**100%**	**100%**
GS<50	11%	7%	0%	19%	16%
General Service 50 to 499 kW	22%	63%	18%	60%	72%
General Service 500 to 4999 kW	67%	30%	76%	21%	10%
Large Use	0%	0%	6%	0%	2%
Industrial Program-Process & System Upgrades					**200%**
GS<50					0%
General Service 50 to 499 kW					0%
General Service 500 to 4999 kW					47%
Large Use					53%
Industrial Program-Energy Manager	**0%**	**100%**	**100%**	**100%**	**100%**
GS<50		0%	0%	0%	0%
General Service 50 to 499 kW		30%	0%	0%	0%
General Service 500 to 4999 kW		70%	30%	42%	50%
Large Use		0%	70%	58%	50%
Industrial Program-Retrofit	**100%**				
GS<50	18%				
General Service 50 to 499 kW	56%				
General Service 500 to 4999 kW	25%				
Large Use	1%				
Industrial Program-Demand Response 3	**100%**	**100%**	**100%**	**100%**	
GS<50	0%	0%	0%	0%	
General Service 50 to 499 kW	0%	0%	25%	0%	
General Service 500 to 4999 kW	25%	25%	75%	25%	
Large Use	75%	75%	0%	75%	
Conservation Fund Pilot-Loblaws Pilot					**100%**
General Service 50 to 499 kW					50%
General Service 500 to 4999 kW					50%
Conservation Fund Pilot - SEG					**100%**
General Service 50 to 499 kW					50%
General Service 500 to 4999 kW					50%
Other-Time of Use Savings					

Demand Savings Allocation	Percentage allocation				
Program/ Initiative	**2011**	**2012**	**2013**	**2014**	**2015**
Residential					
Other-LDC Pilots				**100%**	
General Service 50 to 499 kW				50%	
General Service 500 to 4999 kW				50%	
Non-Residential Province-Wide Programs-Save on Energy Audit Funding Progra					**100%**
GS<50					16%
General Service 50 to 499 kW					71%
General Service 500 to 4999 kW					10%
Large Use					2%
Non-Residential Province-Wide Programs-Save on Energy Retrofit Program					**100%**
GS<50					14%
500-4999					32%
50-499					49%
Large Use					5%
Non-Residential Province-Wide Programs-Save on Energy Retrofit Program - P4					**100%**
GS<50					14%
500-4999					32%
50-499					49%
Large Use					5%
Business Program- Retrofit (Streetlight project)					
Streetlighting					
Pre-2011 Programs completed in 2011-Electricity Retrofit Incentive Program	**100%**	**100%**			
GS<50	16%	0%			
General Service 50 to 499 kW	56%	50%			
General Service 500 to 4999 kW	28%	50%			
Large Use	0%	0%			
Pre-2011 Programs completed in 2011-High Performance New Construction	**100%**	**100%**			
GS<50	16%	0%			
General Service 50 to 499 kW	56%	50%			
General Service 500 to 4999 kW	28%	50%			
Large Use	0%	0%			
Grand Total					

ERZ-Staff-14

Reference(s): Table 4-c, Tab 4 of LRAMVA Work Form (Attachment 42)
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.

Response:

a) The City of Mississauga engaged in the IESO's Retrofit Program (Project ID: 105215) to replace high-pressure sodium street lights with LED street lights and new lighting controls over two phases. The first phase was completed in 2013; the City of Mississauga replaced 20,698 high pressure sodium street lights with LED lights. The second phase was completed in 2016. The first phase in 2013 contributes to net energy savings of 5,110,764 kWh. Please see attached "IESO Streetlighting Project Verified Results" as support.

b) The Street Light project contributed to both energy and demand savings. Enersource RZ has claimed energy savings in 2013 and the persistence of these savings into the future years 2014 and 2015. This is shown in Attachment 42, Tab "4. 2011-2014 LRAM" row 381, where the first phase was completed and savings were calculated. Enersource has also claimed demand savings in 2013, 2014 and 2015 for the Streetlights rate class. This is shown in Attachment 42, Tab "8. Streetlighting".

c) To assess the impact of the lost revenue in relation of CDM, where streetlight class is billed on kW, the street lighting savings should be claimed on kW. As detailed above, the demand savings claimed are shown in Attachment 42, Tab "8. Streetlighting".

It is important to note that demand savings for the City of Mississauga's retrofit streetlight project do not appear on the IESO's Final Verified Result Report in 2013 as the reduction to peak demand occur outside the IESO's peak hours. According to the Chapter 3 Incentive Rate-Setting Applications of the OEB "Filing Requirements For Electricity Distribution Rate Applications – 2017 Edition for 2018 Rate Applications", on Page 17, it quoted "A statement confirming whether additional documentation or data was provided in support of projects that were not included in the LDC's Final CDM Annual Report (i.e., street lighting projects). This data can be added to the work form in Tab 8 as applicable." Therefore, Tab "8. Streetlighting" in Attachment 42 had been included to reflect the demand savings that were not included in Enersource's Final CDM Annual Report. Demand savings were calculated based on the difference of billed kW demand from Enersource's billing system on the streetlight account and compared to the billed kW based on the pre-completion of LED street lights project. The difference was determined to be savings achieved from street lighting project.

d) Enersource RZ received persistence information from the IESO related to this Street Lighting Project. The persistence information was included on Tab "4. 2011-2014 LRAM" on row 381". Please see attached spreadsheet (Ref: IESO Streetlighting Project Verified Results) as support.

e) According to the IESO support on the Street Lighting Project (Ref: IESO Streetlighting Project Verified Results), Street Lighting savings were reported in both Gross and Net savings in kWh. The total gross saving reported was 8,433,152 kWh, and the net energy saving of 5,110,764 kWh was adjusted by multiplying the Realization Rate of 95% and Net to Gross Ratio of 64%.

f) Changes have been made to the template to update the energy savings persisting to future years.

Unique Identifier (System Generated)	LDC (if applicable)	Project Completion Date (mm/dd/yyyy)	Implementation Year	Program	Initiative	Sector	Track	Measure	Net Verified Lifetime Energy Savings (kWh)	Net Verified Lifetime Energy Savings to 2014 (kWh)	2013	2014
105215	Enersource Hydro Mississauga Inc.	31/12/2013	2013b	Business	Retrofit	Commercial	Custom	Lighting	7,709,329	1,509,113	754,557	754,557
105215	Enersource Hydro Mississauga Inc.	31/12/2013	2013b	Business	Retrofit	Commercial	Custom	Lighting	44,507,518	8,712,415	4,356,208	4,356,208

Unique Identifier (System Generated)	LDC (if applicable)	Project Completion Date (mm/dd/yyyy)	Implementation Year	Program	Initiative	Sector	Track	Measure	2015	2016	2017	2018
105215	Enersource Hydro Mississauga Inc.	31/12/2013	2013b	Business	Retrofit	Commercial	Custom	Lighting	754,557	754,557	754,557	754,557
105215	Enersource Hydro Mississauga Inc.	31/12/2013	2013b	Business	Retrofit	Commercial	Custom	Lighting	4,356,208	4,356,208	4,356,208	4,356,208

Unique Identifier (System Generated)	LDC (if applicable)	Project Completion Date (mm/dd/yyyy)	Implementation Year	Program	Initiative	Sector	Track	Measure	2019	2020	2021	2022
105215	Enersource Hydro Mississauga Inc.	31/12/2013	2013b	Business	Retrofit	Commercial	Custom	Lighting	754,557	715,433	693,804	693,804
105215	Enersource Hydro Mississauga Inc.	31/12/2013	2013b	Business	Retrofit	Commercial	Custom	Lighting	4,356,208	4,130,339	4,005,473	4,005,473

Unique Identifier (System Generated)	LDC (if applicable)	Project Completion Date (mm/dd/yyyy)	Implementation Year	Program	Initiative	Sector	Track	Measure	2023
105215	Enersource Hydro Mississauga Inc.	31/12/2013	2013b	Business	Retrofit	Commercial	Custom	Lighting	324,392
105215	Enersource Hydro Mississauga Inc.	31/12/2013	2013b	Business	Retrofit	Commercial	Custom	Lighting	1,872,779

ERZ-Staff-15

Reference(s): 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

Response:

a) In the 2014 LRAMVA work form, the following cells were updated:
   i) Residential Rate Class. N510 has been revised from 0 to “12” months to represent the IESO implemented LDC Pilot Projects which focused on optimizing overall operations and systems.
   ii) Allocation has been updated to the work form on Row 507, Columns Y to AL for the allocation by rate class.
   iii) Allocation has been updated to the work form on Row 510, Columns Y to AL for the allocation by rate class.

b) The correct information is indicated below:
   i) Information has been updated to Table 4-d on Cell “N510” for 12 months of demand savings claimed.
   ii) The rate class allocation for Row 507 has been updated to 100% in the Residential Rate class.
   iii) The rate class allocation for Row 507 has been updated to 100% in the GS 500-4999 Rate class.

ERZ-Staff-16

Reference(s): 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**

Response:

a) With respect to “LDC Pilots in 2014” and “Loblaw Pilot in 2015”, the energy and demand savings for both 2014 and 2015 pilots were derived from the implementation of a 2-year Conservation Fund pilot entitled “Loblaws Results-Based Performance Optimization (RBPO) Pilot Program”. The pilot was implemented by Energy Profiles Limited and Loblaws Properties Limited, and focused on optimizing overall operations and systems at individual stores. Over a 2 year period, starting in 2014, Loblaws received IESO pay-for-performance incentives based on verified savings which were calculated for the entire building and where savings persisted to future years. Due to the nature of the pilot programs and their similarity to the energy efficiency programs 12 months of demand savings were claimed.

With respect to the Conservation Fund Pilot – SEG was a strategic energy management pilot program implemented by the IESO. This program identified energy management champions at a customer level to identify energy saving solutions. Due to the nature of this pilot program at its similarity to the energy efficiency programs 12 months of demand savings were claimed.

ERZ-Staff-17

Reference(s): Tabs 4 and 5 of LRAMVA Work Form (Attachment 42)
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.

Response:

In the Board's EB-2012-0033 Decision and Order the Board stated, "The Board is not convinced that the inclusion of the 7.18 GWh which has been included in the load forecast will have such a material effect over the term of the forecast that it necessitates Enersource adjusting its load forecast. As such, the Board will accept the load forecast as submitted."

The Board's decision was based on the evidence provided in the application. It would be incorrect to suggest that the 2013 load forecast included a reduction of 7.18 GWh related to 2011. The 2013 load forecast was developed by a multivariate regression model which incorporated 16 years of actual data to predict future load and as a result the impact related to a single year of data would immaterially influence the forecast year.

ERZ-Staff-18

Reference(s):

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.

Response:

Please find attached the excel copies of Enersource's 2014 and 2015 Final CDM Annual Report, and the 2011-2015 Persistence Savings Report issued by the IESO.

ERZ-Staff-19

Reference(s):

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.

Response:

Alectra Utilities' has made changes to the Enersource rate zone LRAMVA Work Form as a result of its responses to interrogatories. In addition, the work form has been updated to include the savings related to 2015 CDM programs from the IESO's recently published Final Verified 2016 Annual LDC CDM Program Results Report. Based on the Final Verified 2016 Annual LDC CDM Program Results Report, an additional 14,257,825 net kWh energy savings and 2,657 net kW peak demand savings have been identified for the year of 2015. The LRAMVA claim changed from $2,146,406 to $2,278,556. Please see attached an updated version of the Work Form.

ERZ-Staff-20

Reference(s): 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.

Response:

a) Alectra Utilities' is seeking the Ontario Energy Board's ("OEB") approval for incremental capital funding through the incremental capital module ("ICM") for the Enersource Rate Zone ("ERZ"). Alectra Utilities' predecessor, Enersource Hydro Mississauga filed its last rebasing application for rates effective January 1, 2013 on April 12, 2012 (EB-2012-0033). At the time of that application filing, the Advanced Capital Module ("ACM") funding mechanism was not available. The OEB issued the *Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module (the* "ACM Report"), on September 18, 2014. Alectra Utilities is not seeking ACM funding for the ERZ.

Distributors proposing amounts for recovery by way of an ACM or ICM must meet all three of the following criteria, as set out in Section 4.1.5, p.17 of the ACM Report.

1. Materiality – Each incremental capital project or expenditure must be material and clearly have a significant influence on the operation of the distributor For a consolidating

utility, as identified in the OEB's Report on Rate Making for Distributor Consolidations, Section C – Incremental Capital Investments during the Deferral Period, at p. 10:

> *"In regards to making an application for an ICM, the materiality thresholds for purposes of the ICM policy shall be calculated based on the individual distributor's accounts, i.e. depreciation expense, and not the consolidated entity's."*

Alectra Utilities' project materiality for the ERZ is $589,950. All of Alectra Utilities' ICM projects for the ERZ exceed the project materiality threshold. Further, the OEB expects that any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount. Alectra Utilities' total ICM projects are within the maximum eligible incremental capital amount calculated in Table 136 of Exhibit 2, Tab 4, Schedule 11, p.24 of the Application.

2. Need – A distributor must pass the Means Test; amounts must be based on discrete projects and directly related to the claimed driver, and must be clearly outside of the base upon which rates were derived. Each proposed ICM project is discrete in that each project has a defined scope, schedule and cost. Each proposed ICM project has been evaluated in the asset management and capital planning processes as being required for 2018. Information with respect to the driver of each project is provided in each business case in Exhibit 3, Tab 1, Schedule 1, Attachment 47 – ICM Business Cases Enersource RZ. Further, the OEB applies the Means Test to assess the need for the ICM project. The Means Test states that if a distributor's regulated return exceeds 300 basis points above the deemed ROE, the funding will not be allowed. The ROE for ERZ was calculated to be 6.13%, 280 basis points below its OEB-approved ROE of 8.93%.

3. Prudence – As identified on page 17 of the ACM Report, "*The amounts incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers."* Each ICM project for which Alectra Utilities is seeking approval for the ERZ represents the most cost effective option for ratepayers. The analysis of options is provided in the business case for each eligible capital project in Exhibit 3, Tab 1, Schedule 1, Attachment 47 – ICM Business Cases Enersource RZ, as identified below.

Table 1 – ERZ Capital Project Business Case Listing

Enersource Rate Zone	Reference Attachment 47 - ICM Business Cases Enersource RZ
Roads - QEW - Evans to Cawthra	Exhibit 3, Tab 1, Schedule 1, Attachment 47, p.4
OH Rebuild - Lake/John	Exhibit 3, Tab 1, Schedule 1, Attachment 47, p.50
OH Rebuild - Church	Exhibit 3, Tab 1, Schedule 1, Attachment 47, p.58
Subdivision Rebuild - Glen Erin & Montevideo - Section 1	Exhibit 3, Tab 1, Schedule 1, Attachment 47, p.10
Credit Woodlands Crt/Wiltshire	Exhibit 3, Tab 1, Schedule 1, Attachment 47, p.23
Tenth Line Main Feeder	Exhibit 3, Tab 1, Schedule 1, Attachment 47, p.29
Folkway & Erin Mills Main Feeder	Exhibit 3, Tab 1, Schedule 1, Attachment 47, p.35
Glen Erin & Battleford	Exhibit 3, Tab 1, Schedule 1, Attachment 47, p.16
City Centre Drive Cable Renewal	Exhibit 3, Tab 1, Schedule 1, Attachment 47, p.43
Leaking Transformer Replacement Project	Exhibit 3, Tab 1, Schedule 1, Attachment 47, p.68
Substation - York MS	Exhibit 3, Tab 1, Schedule 1, Attachment 47, p.75

b) Please see Alectra Utilities' response to G-Staff-3.

ERZ-Staff-21

Reference(s): E2/T4/S11, p.4, table 129

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

Response:

Table 1 provides actual August year-to-date capital expenditures for the Enersource RZ.

Table 1 – Capital expenditures – YTD August 2017

Category	YTD August 2017 ($000s)
System Access	$4,733
System Renewal	$22,514
System Service	$6,793
General Plant	$1,977
Total	**$36,017**

ERZ-Staff-22

Reference(s): E2/T4/S11, p.4

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.

Response:

a) For each project, a technical alternative is determined based on implementation costs, scope, feasibility and other technical criteria specific to the investment need.

b) Risk adjusted costs were not utilized in the Enersource rate zone.

c) Discretionary project objectives are confirmed and preferable solutions are developed which meet the desired outcome of the project. This evaluation is performed through the business case development which evaluates projects against pre-defined investment criteria. Projects are scored by identifying their risk and/or benefits as they relate to business values as outlined in Table 25 to Table 27 in Alectra Utilities' DSP for the Enersource RZ (E3/T1/S1/Attachment 50, Pages 113 to 115). Evaluated scoring on business value for each project can be found in each business case in Appendix E – Business Cases Alectra Utilities' DSP for the Enersource RZ (E3/T1/S1/Attachment 50, Page 403). Please see response to BOMA-112 part a) iv) for a detailed explanation on the methodology, criteria and results of the project prioritization process. Project risk evaluations are quantified through scoring in each business case. Operations personnel completing the project business cases rate the projects based on the best suited descriptions within the criteria categories:

Customer Focus:

Service Quality

10 - Improvement from non-compliance to compliance

8 - Significant improvement to ESQR

5 - Improvement of multiple ESQRs

3 - Makes an improvement or prevents degradation of 1 ESQR

0 - No impact on any ESQR

Customer Satisfaction

10 - Direct positive impact that will be reflected on next customer survey

8 - Adds value or service that customers have identified through survey or some other means

5 - Improves customer experience (a large user or 1,000 RES customers)

3 - Positive improvement to customer experience (non-quantifiable)

0 - No impact on Customer Service

Reputational Risk

10 - Prevents or significantly reduces likelyhood of irreparable brand damage

8 - Positive impact on brand

5 - Helps preserve brand

3 - May mitigate brand risk

0 - No brand impact

Operational Effectiveness:

Safety

10 - Potential loss of life

8 - Non-reversible injury

5 - Medical aid injury

3 - First aid injury

0 - No safety risk

Environmental

10 - Environmental disaster

8 - High environmental impact

5 - Medium environmental impact

3 - Low environmental impact
0 - None

System Reliability
10 - Prevent 100,000 customer minutes of outage
8 - Prevent 80,000 customer minutes of outage
5 - Prevent 50,000 customer minutes of outage
3 - Prevent 30,000 customer minutes of outage
0 - No impact on customer minutes of outage

System Expansion
10 - New infrastructure to avert major system constraint/risk
8 - New infrastructure required to support service capacity
5 - Upgrade existing infrastructure to support existing service capacity
3 - Provide system capacity without compromising service to existing customers
0 - No Impact on system capacity

System Renewal
10 - ACA health index "Very Poor"
8 - ACA health index "Poor"
5 - ACA health index "Fair"
3 - ACA health index "Good"
0 - ACA health index "Very Good" or N/A

Financial Performance:

Cost Efficiencies
10 - > $100,000
8 - > $80,000
5 - > $50,000
3 - > $30,000
0 - No significant amount

Ongoing Costs
-0 - No significant amount
-3 - < $30,000
-5 - < $50,000

-8 - < $80,000

-10 < $100,000

Each choice within the above categories assigns a score to the priority of the project. The total of each category is multiplied by the weighting of the category. The weighted scores for each category are added together for a total score. To normalize the scores for cost, each project score is multiplied by the project cost divided by the total budget.

ERZ-Staff-23

Reference(s): E2/T4/S11, p.5

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

Response:

a) The following projects form the majority of the investments in the System Access category.

Project No	Project Description
C0531	ROAD PROJECTS
C0541	NEW SUBDIVISIONS
C0542	INDUSTRIAL/ COMMERCIAL SERVICES
C0598	METERING EQUIPMENT
C0899	SMART METERING IN NEW CONDO
C0532	LRT

<u>Subdivision (C0531), Industrial/Commerical Services (C0542) and Metering Equipment (C0598):</u>

The budget information for New Subdivisions, Industrial Commercial Services and Metering equipment is based the latest information from builders and developers.

<u>Road Authority (C0531) and LRT projects (C0532):</u>

The timelines for road Authority and LRT projects are based on discussions with Metrolinx and the City of Mississauga.

Metrolinx transit project plans include Utility Preliminary Design, Costs, Schedule and Preparatory Activities, which are currently being performed in 2017. Alectra Utilities is confident that this work will materialize in 2018 based on the latest available information. Design work for some of the preparatory activities is underway for the following areas:

- Dundas & Hurontario
- QEW to Sherobee Rd.
- Rathburn
- Burnhamthorpe – from Hurontario to Living Arts Drive.

Further, the City of Mississauga has completed the Environmental Assessment study for the Living Arts Drive extension, which will involve installation of new ductbanks. The City of Mississauga anticipates that work on the road extension will commence in 2018 which aligns with Alectra Utilities' schedule and proposed timelines.

b) Alectra Utilities' has nearly certain to high confidence in each of the drivers that determine the capital requirement for the first two years of the proposed investment plan, which is based on the latest information obtained at the time the budget was completed.

ERZ-Staff-24

Reference(s): 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.***

Reference(s): 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**

Reference(s): 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.

Response:

a) Alectra Utilities' continues to operate on a strategy of running single phase pad mounted transformers to failure, however, in cases where inspections determine, that a transformer poses a safety or environmental risk, these identified transformers are replaced.

b) Alectra Utilities' inspection methodology in the Enersource RZ has evolved to capture improved condition parameters. The transformer inspection practice was updated in 2013 to include opening of the transformer door to inspect the internal components of the device. This method of inspection provides greater detail regarding the internal condition of oil containment features, levels of corrosion and cable and connection issues**.**

c) Alectra Utilities' continues to adhere to federal and provincial legislation governing oil spills into the environment. This project was created as a result of actual risks experienced by Alectra Utilities in addressing oil spills into the environment. The Enersource RZ currently has 25,329 transformers located throughout its distribution system, including public right-of-ways, rear lots of private properties, commercial lands near high traffic areas, as well as customer-owned vault locations. From 2013 to 2016, 2,052 transformers that were identified to be leaking oil or containing PCBs were replaced. Transformer oil leaks at 103 sites led to environmental remediation. Over the four year period, the Enersource RZ incurred approximately $5.6M in environmental remediation costs as well as $19.4M in capital expenditures for transformer replacement, which were not included in rates. Alectra Utilities' has developed a project to address the remaining backlog of 2,244 transformers requiring timely replacements.

d) From 2013 to 2016, Alectra Utilities' inspected its distribution transformers, resulting in the identification of a large number of transformers showing signs of oil leaks and/or containing polychlorinated biphenyl (PCB) oil. As of January 1, 2017, 2,244 transformers have been identified as showing signs of oils leaks and/or containing PCB, and are included as part of the transformer replacement project.

e) Leaking PCB transformers are given a higher replacement priority or over non-PCB leaking transformers. However, non PCB transformers found to be leaking must also be replaced to mitigate remediation costs from oil spills, address loss of enjoyment of property and loss of reputation. All spills must be remediated and any spills in excess of 100 litres or generating 1 gm or more of solid PCB must be reported to Provincial and Federal agencies. Clause 93 of the Environmental Protection Act states "The owner of a pollutant and the person having control of a pollutant that is spilled and that causes or is likely to cause an adverse effect shall forthwith do everything practicable to prevent, eliminate and ameliorate the adverse effect and to restore the natural environment." Customers, employees and the public must be informed of and protected from hazards that may arise in connection with the Alectra Utilities assets. The risk of not addressing potentially leaking transformers could directly impact the health or safety of those in contact with these assets. Alectra Utilities' is proactively resolving this concern by replacing the transformers indicating signs of leaking and by remediating contaminated sites in the Enersource Rate Zone

f) Alectra Utilities' prioritizes leaking transformers by the scale of the leak observed. A grading method is used to identify major, moderate and minor transformer oil leaks. Different methods of ranking leaks are used for different transformer types including pictorial examples for use in the inspection process.

See table 130 R2 below to reflect the each transformer type categorized by leak severity

Table 130 R2

Transformer Type	Leak category	PCB Transformers Indicating Leaking Oil	Non-Leaking Transformers with PCB Oil	Transformers (Non-PCB) Indicating Signs of Leaking	Total
Single-Phase Pad Mount	Major	0	0	26	26
	Moderate	0	0	118	118
	Minor	3	0	589	592
	Non-Leaking	0	95	0	95
	Sub Total	**3**	**95**	**733**	**831**
Three-Phase Pad Mount	Major	0	0	4	4
	Moderate	0	0	20	20
	Minor	2	0	47	49
	Non-Leaking	0	6	0	6
	Sub Total	**2**	**6**	**71**	79
Vault Transformers	Major	0	0	15	15
	Moderate	0	0	75	75
	Minor	18	0	624	642
	Non-Leaking	0	38	0	38
	Sub Total	**18**	**38**	**714**	770
Pole Mount Transformers	Major	0	0	17	17
	Moderate	0	0	41	41
	Minor	0	0	475	475
	Non-Leaking	0	31	0	31
	Sub Total	**0**	**31**	**533**	**564**
	Total	**23**	**170**	**2051**	**2244**

g) Alectra Utilities' has examined options to mitigate the risk of leaking transformer and has determined that the only viable solution is to replace them. Alectra Utilities' has been in contact with transformer manufacturers to discuss Alectra Utilities' concerns over the degree of corrosion and leaks experienced. Alectra Utilities' is currently identifying changes to its specifications for on grade pad-mounted transformers to improve corrosion protection and oil containment features as well as warranty terms.

h) All of the forecast expenditures associated with the transformer replacement project is addressed in the ICM.

i) The reference to substandard in the context of E2/T4/S11, p.16 refers to transformers found to be in a condition where they are no longer deemed suitable to remain in service. Substandard as opposed to failed means the unit is still providing electricity to our customers; however, the unit is compromised from an oil containment perspective or from a public safety perspective. This includes conditions where corrosion has advanced to a degree such that the transformer is leaking oil, where the locking mechanism is no longer secure, or where corrosion has advanced to a degree on the access door or skirt such that the high voltage and low voltage components are no longer secure from tampering or probing.

ERZ-Staff-25

Reference(s): 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.**

Response:

a) Yes, the 2018 forecast year expenditures include all 2018 ICM expenditures.

b) Please see Table 1 below for the 2018 Forecast excluding all ICM expenditures.

Table 1 – 2018 capital expenditures, excluding ICM expenditures

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		10,385	13,797	13,812	12,752	10,812
System Renewal	16,224	20,854	31,244	37,472		35,196	37,386		21,225	42,150	41,520	40,160	36,940
System Service	9,860	8,167	10,951	16,297		12,724	10,104	(2)	11,196	13,407	13,717	13,522	14,007
System Service				40,479	(1)								
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	62,402		49,478	76,933	77,459	73,186	67,627

NOTE (1): Original table excluded the Hydro One payment for Churchill Meadows
NOTE (2): 2017 System Service was reduced for portion of York MS expected in 2017

ERZ-Staff-26

Reference(s): 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?**

Response:

a) 28% of cables in the Enersource RZ were installed prior to 1989.

b) 95% of cable failures from January 2014 to January 2016 were associated with cables installed prior to 1989.

c) There is not a distinct failure curve for cables installed prior to 1989 and cables installed after 1989. Differences in the Health Index for cables are based on non-tree retardant cross-linked polyethylene (Non-TR-XLPE) direct buried, tree retardant cross-linked polyethylene (TR-XLPE) direct buried, and TR-XLPE in duct. This distinction is made because non-TR-XLPE is prone to electrical trees and TR-XLPE is not prone to electrical trees. Treeing is an electrical pre-breakdown in the insulation of the cable which leads to electrical faults in the cable. Cables that are direct buried also do not last as long as cables in duct. The majority of cables installed prior to1989 fall into the first two categories.

d) Alectra Utilities' cannot determine the ratio of failures to total population.

e) The average age of failed direct buried cable is approximately 38 years based on age of failed cable at the time of failure from January 2014 to January 2016.

f) The underground cables being replaced as part of the subdivision renewal projects are primarily early generation underground cables, which are unjacketed and/or direct buried, leading to rising numbers of outages and having an adverse impact on reliability. Underground cables have been identified in the Kinectrics' ACA as the asset class with the highest percentage of poor or very poor condition assets. The consequence of failures and impact on reliability for buried cables are included in the following Business Cases, filed as Attachment 47.

- Glen Erin & Montevideo – Attachment 47 page 10
- Glen Erin & Battleford – Attachment 47 page 16
- Credit Woodlands & Wiltshire – Attachment 47 Page 21
- Tenth Line Main feeder – Attachment 47 page 27
- Folkway & Erin Mills – Attachment 47 page 34

The probability of a cable failure is driven by the number of existing cable faults within the rebuild area as provided in the Enersource RZ business cases in Exhibit 3, Tab 1, Schedule 1, Attachment 47.

g) Alectra Utilities' is proposing to install all direct buried cable into duct or conduit for the subdivision rebuild projects in the Enersource RZ. This will reduce the number of outages in these areas and improve reliability. Further, this will reduce future replacement costs associated with digging up cable faults, splicing and surface restoration. The incremental costs to install cables in duct is $10/duct for the material and $20 in labour costs.

ERZ-Staff-27

Reference(s): 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?

Response:

a) In both the online feedback portal and telephone surveys, a majority of Enersource RZ customers supported some level of investment in the Incremental Capital Module (ICM) projects that were presented. Additionally, in the Enersource RZ telephone surveys, customers in all rate classes expressed that "Ensuring reliable electrical service" was one of their top two customer priorities.

b) Yes, the ICM process was explained to ratepayers during the customer consultation. The following explanation of ICM was provided to ratepayers in the telephone survey (see Appendix 6.1, Enersource Residential Telephone Questionnaire, Page 12):

> *The previous section of this survey addressed Enersource's 5-year capital plan. While that plan is subject to customer feedback and approval by the provincial energy regulator, most of the capital projects can be funded through existing approved distribution rates.*

> *That said, Enersource has identified immediate capital investments for 2018 in its proposed 5-year capital plan that are not funded through existing distribution rates.*
>
> *The incremental funding required is built into Enersource's estimated 5-year capital plan, but has not been approved.*
>
> *As a result, Enersource plans to apply to the provincial energy regulator this year for incremental capital funding in 2018 to address immediate infrastructure investment needs.*

A similar explanation was also provided for those Enersource RZ customers who chose to complete the Online Feedback Portal (see Appendix 5.0, Alectra Utilities Online Feedback Portal Layout, Page 33).

ERZ-Staff-28

Reference(s): 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?

Response:

a) Alectra Utilities' completed an assessment of the reliability impact for the three scenarios presented in the Customer Engagement for customer input and feedback. The scenario that the level of reliability would eventually decline was assessed under the approach 50% of the proposed ICM projects would be approved. The assessment of the impact was over the five year period 2018-2022. The term decline was determined relative to the intent to maintain the overall system reliability levels which the proposed ICM projects are expected to achieve. The bill impacts presented in the Customer Engagement were calculated by comparing a current customer bill, with and without the proposed ICM rate riders. The total bill impact for each rate class was allocated to System Access, System Service and System Renewal based on the percentage allocation of capital expenditure for the respective category to total capital expenditures for all three categories. For example, System Access capital expenditures of $1.3MM, represents 5% of the total proposed ICM capital expenditures of $28.6MM. Alectra Utilities' allocated 5% of the total residential bill impact of $0.42, or $0.02, to the System Access category.

b) Table 1 identifies the ranges of reliability declining impacts assessed under each scenario in SAIDI minutes.

Table 1 – Assessment of Reliability Impact for Scenarios for SAIDI (minutes)

Year	Reliability Eventually Declines	Reliability Could Decline Significantly
2018	0.45 – 1.22	1.22 – 1.40
2019	1.22 – 2.35	1.40 – 2.82
2020	1.74 – 3.09	2.18 – 3.75
2021	2.48 – 4.51	2.52 – 5.58
2022	3.50 – 6.06	4.13 – 7.55

Table 2 identifies the ranges of reliability declining impacts assessed under each scenario in SAIDI % relative to 2016 levels.

Table 2 – Impact to Reliability in terms of SAIDI % (relative to 2016)

Year	Reliability Eventually Declines	Reliability Could Decline Significantly
2018	0.93% - 2.52%	2.52% - 2.88%
2019	2.52% - 4.84%	2.88% - 5.80%
2020	3.58% - 6.37%	4.48% - 7.73%
2021	5.10% - 9.29%	5.18% - 11.51%
2022	7.22% - 12.50%	8.51% - 15.57%

ERZ-Staff-29

Reference(s): 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.

Response:

a) The reduction to Alectra Utilities' revised ICM request by $4,396,317 was due to the deferral of the Webb MS ICM project. The construction of Webb MS was planned to start in 2017 with an in-service date in 2018.The ICM request for Webb MS included expenditure for both 2017 and 2018 in the amount of $1,841,997 and $2,590,753 respectively, for a total of $4,432,750. This was partially offset by an update to the York MS project investment by $36,433.

The 2018 capital forecast reduction of $5,885,000 includes pacing and adjustment of 2018 project expenditures that include both Webb MS as well as other distribution capital investments as listed in Table 1 below.

Table 1: 2018 Capital Forecast Adjustment - Pacing Projects

Project	CAPEX ($000)	Adjustment
Webb MS (2018 Expenditure)	-$2,591	Deferred to 2020
LRT Project	-$2,500	Delayed Start 6 Months
Webb MS Feeders	-$1,249	Deferred to 2020
Canopy – Mavis Facility	-$731	Cancelled
Derry-WCB to Argentia	$1,186	Brought forward into 2018 from 2019
Total	**-$5,885**	

b) As outlined in section 3.1.6 Customer Engagement Activities (5.4.1.f) of Alectra Utilities' Distribution System Plan for the Enersource RZ (E3/T1/S1), Alectra Utilities' engaged Innovative Research to assist in the design and implementation of a customer engagement and consultation process, as well as to collect and document input received through that process. Based on feedback from customers, Mississauga customers expect Alectra Utilities' to deliver a robust capital investment plan than ensures a highly reliable and modern distribution system. Most customers support some form of investment plan that ensures a consistently reliable and modern distribution system. When presented with specific capital investment projects to address system constraints, a majority of customers support some level of investment to help maintain reliability. Further, customers identified a stronger preference for system renewal investments compared to system service investments. Alectra Utilities' has incorporated the identified customer priorities and preferences into the investment plan by pacing and deferring certain system service expansion projects such as Webb MS. As the York MS investment is required to address the need to update equipment and configuration of an existing station to bring these in line with current standards and improve reliability, the project was determined to be in alignment with customer preference to ensure a consistently reliable and modern distribution system.

As provided in the Business Case for York MS (Attachment 47, Page 69), the upgrade to York MS is required to service the projected new loads in the Meadowvale Business Park without exceeding the established planning loading limits. Further, the case explains that failure of a power transformer may result in prolonged outage to approximately 600 commercial, industrial and institutional customers that would negatively impact system reliability and result in significant environmental remediation costs.

c) The description of York MS investment drivers (i.e. 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) is provided in York MS Business Case (Attachment 47, page 69). The investment requirement at York MS is firstly driven by the projected growth of commercial, industrial and institutional demand in Meadowvale Business Park area as well as system capacity necessary to provide reliable back-up for Argentia, Century and Winston municipal substations. As the second largest employment district in Mississauga, the Meadowvale Business Park the location was the area of business for 47,600 employees. The secondary driver for the York MS project is to mitigate the reliability issues associated with the cable egress, protection and sub-standard station configuration. The station is one of two remaining outdoor 44kV/13.8kV Municipal Substations in the Mississauga. Outdoor station equipment is susceptible to contamination from nearby highways, animals, and weather, which introduces operating risks and increased maintenance as well as inspection costs. A detailed discussion on the relative contribution of each of these factors as project drivers in included in the Business case, filed as Attachment 47, pages 69-75.

ERZ-Staff-30

Reference(s): E2/T4/S11, p.27
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.

Response:

The 2018 capital forecast of $77,233,772 noted as reference 1 is presented exclusive of transition costs and synergy savings. The 2018 Distribution System Plan Capex of $72,682,772 at reference 2, excludes General Plant investments that were planned by the former Enersource as a stand-alone utility. As stated on page 9 of the Enersource Rate Zone DSP, "In light of the formation of Alectra Utilities' in February 2017, certain General Plant investments that were planned by the former Enersource as a stand-alone utility will instead be evaluated, prioritized, and executed by Alectra Utilities' as a consolidated entity to maximize efficiency gains and value creation. As a result, these investments are no longer specific to the Enersource Rate Zone and therefore have been excluded from this Enersource RZ DSP. Instead, these investments will form part of Alectra Utilities' DSP that will cover all four rate zones.

ERZ-Staff-31

Reference(s): 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.

Response:

a) On page 39 of the Board's Decision in Enersource's 2013 COS Application, issued December 13, 2012, the Board approved a 2013 OM&A amount of $52.565 million. In its Decision, the Board stated, "*A 2.5% compound annual increase applied to the 2011 actual OM&A amount of $50.032 million results in a 2013 OM&A amount of $52.565 million. This results in a reduction of $8.446 in Enersource's 2013 OM&A forecast. The 2013 level of $52.565 million represents an approximate 6% average annual increase from the 2008 Board approved level, a 9% average annual increase from the 2008 actual and a 6.4% average annual increase from the 2009 actual. The Board finds that this level of increase is sufficient to accommodate inflation, customer growth, and incremental expenditures over the period*".

ERZ-Staff-32

Reference(s): 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?**

Response:

a) Please see Alectra Utilities' response to ERZ-Staff-29 b).

b) Investment of Webb MS was included as part of substation investment category in Alectra Utilities' customer engagement both for the Enersource Rate Zone ("ERZ") Distribution System Plan ("DSP") and Incremental Capital Module ("ICM"). A brief description of the Webb MS and York MS projects, the area of the City of Mississauga that would be impacted and the importance of the investments, were included in the Customer Feedback Portal. Through the engagement process, customers identified a stronger preference for system renewal investments compared to system service investments as outlined on Innovative Customer Engagement Report (Attachment 51, p. 17-18). On p.323 of Attachment 51, Innovative Customer Engagement Report Enersource RZ, in the Customer Feedback Portal, Webb MS was identified as one of two system service investments. Webb MS was described as a "growth driven investment to provide additional capacity in the Mississauga downtown area". On p. 324 of Attachment 51, the importance of system service investments was presented in the Customer Feedback Portal -"Substations are important components of the distribution system that house the main switches that move electricity to where it's needed, when it's needed. Substations are critical to meeting capacity demand in Mississauga's growing downtown core and industrial areas in the city's northeast".

The need for the Webb MS investment was included in the customer consultation. The removal of this investment was an outcome of customers identifying their needs and preferences through the customer consultation.

ERZ-Staff-33

Reference(s): 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.**

Response:

a) Alectra Utilities' completed the most robust customer consultation ever undertaken by an Ontario LDC, consisting of: 6 customer focus groups; 17,595 voluntary online surveys responses among low-volume customers (residential and GS < 50 kW); 7 online surveys among large users; and n=1,822 randomly selected telephone interviews among low-volume and GS > 50kW customers.

Planning and developing Alectra Utilities' customer engagement program began in March 2017, immediately following the legal formation of the utility. Engagement with customers began by mid-April 2017 with the recruiting of low-volume customers to participate in focus groups designed to better understand the manner in which information needed to be presented to customers for them to be able to provide meaningful feedback on the proposed DSP and ICM options. Customer feedback obtained from these 6 focus groups was used to adjust how information was presented in the online feedback portal and telephone surveys.

With respect to its online feedback portal, Alectra Utilities' actively encouraged all customers to participate in this engagement process using a comprehensive digital promotion campaign. Alectra Utilities leveraged its approximately 370,000 customer email contact list, social media platforms, and promotional advertising embedded on its corporate and legacy websites.

Alectra Utilities' also conducted a total of six telephone surveys in the Enersource and PowerStream RZs among Residential and General Service customers (both GS<50kW and GS>50kW) to provide a quantitative assessment of customer needs and preferences related to various service delivery trade-offs.

The customer engagement associated to this Application also built on the previous customer consultations undertaken by Alectra Utilities' predecessor utilities. Alectra Utilities' previously established understanding of customer needs and priorities helped inform its initial investment plan, and the general framework for this most recent customer engagement process. Because of the ongoing nature of its customer engagement, Alectra Utilities was able to build on the research of the past, improve the processes and complete a comprehensive customer consultation.

Gathering customer input on their preferences and needs through the online feedback portal and telephone surveys required no longer than the **three weeks** documented in the report (May 3 to May 26, 2017). The length of direct customer consultation - through the aforementioned engagement approaches - would have covered the same time span, regardless of when Alectra Utilities' filed its application with the OEB.

b) Alectra Utilities' and its predecessor organizations maintain an ongoing dialogue with customers. In addition, Customer Engagement consultation was undertaken to further inform application with respect to customers' priorities and outcomes. Once the customer consultation was complete, Alectra Utilities' considered the results against the list of proposed projects and revised its capital expenditure plans. There was more than sufficient time to undertake this consideration, given Alectra Utilities' pre-existing dialogue with customers and the nature of the issues: consideration of the Enersource RZ DSP and ICM funding.

ERZ-Staff-34

Reference(s): E3/T1/S1 – Innovative Customer Engagement Report, Page 2

Alectra Utilities 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 Utilities 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.**

Response:

a) Yes, as part of developing the Online Feedback Portal, which informed the design of the customer telephone surveys, Innovative Research Group conducted a series of focus groups with low-volume customers in the Enersource RZ. Two rounds of randomly selected low volume (i.e., Residential and Small Business) focus groups were conducted prior to launching the Online Feedback Portal. *See Customer Engagement Report, Testing the Online Feedback Portal, Page 5 for additional details*.

b) Yes, the response rates are acceptable for the Enersource RZ as a basis for measuring customer satisfaction, wants, and preferences. Through both the Online Feedback Portal and telephone surveys, 3,411 Enersource RZ customers participated in the customer engagement – both voluntarily and through random selection. A detailed breakdown of the total engagement in the Enersource RZ is included below.

Table 1 – Overall Customer Engagement

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**
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**
Total Enersource Engagement	**3,411**				

All low-volume Enersource RZ customers were encouraged to complete the Online Feedback Portal and had equal opportunity to be randomly selected to participate in the telephone surveys. In total, 17,595 unique visitors completed the online feedback form, making this the largest online consultation undertaken by an Ontario electricity utility.

The statistically significant telephone surveys, which engaged a representative sample of Residential, GS < 50 kW and GS > 50 kW customers had the following margins of error:

Residential telephone survey | n=504; margin of error ±4.4%, 19 times out of 20

GS < 50 kW telephone survey | n=200; margin of error ±6.8%, 19 times out of 20

GS > 50 kW telephone survey | n=200; margin of error ±6.7%, 19 times out of 20

An online survey instrument was also designed to engage with Enersource RZ Large Users (5MW+). Among these customers, a census was achieved with seven of the Large Users responding to the online survey.

c) Customer preferences and feedback attained via the customer engagement initiative for the Enersource Rate Zone were first incorporated into the 2017-2022 Capital Investment Plan. Based on this feedback, Alectra Utilities' revised its 2018 capital forecast from $83.118MM to $77.233MM. Once adjustments were made to the 2018 expenditures, the ICM request was revised from $28.643MM to $24.247MM. Please refer to Alectra Utilities' response to ERZ-Staff-38 for a priority listing of proposed ICM projects.

As Alectra Utilities' considers the road widening project at the QEW from Evans to Cawthra, as well as the replacement of leaking transformers, mandatory to meet regulatory compliance, these projects were prioritized first. Considering that the majority of customers were satisfied with the current level of reliability they experience and that customers expect Alectra Utilities to do what is necessary to maintain it, investments related to the system renewal which are designed to maintain overall system reliability were prioritized next. To reflect customer preference for system renewal investments over system service expansion projects as well as interest in conservation initiatives, Alectra Utilities' deferred the construction of Webb MS and removed the project from the proposed ICM request. Additional detail of how Alectra Utilities' incorporated customer feedback can be found in Section 3.1.6 of the Alectra Utilities' DSP for the Enersource Rate Zone (Attachment 50, Pages 282 to 285).

d) The referenced page does not refer to customers' views of Alectra Utilities' performance. As indicated at Exhibit 3, Tab 1, Schedule 1, Attachment 51, p. 13, satisfaction levels across all Enersource RZ rate classes is relatively high. This ICM application is also intended to encompass capital projects, which will provide positive outcomes for customers. Finally, as shown in BOMA 41, Alectra Utilities' is committed to continuous improvement across all of its rate zones.

ERZ-Staff-35

Enersource DSP Feedback

Reference(s): E3/T1/S1 – Innovative Customer Engagement Report, Page 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".

Response:

a) In both the Online Feedback Portal and telephone surveys, Enersource RZ customers expressed the belief that some level of investment should be made to replace aging infrastructure in order to maintain current levels of reliability.

> In the Online Feedback Portal, 39% of Enersource RZ Residential customers believed that *"Enersource should look at the long-term health of the system and proactively spend what is needed to ensure costs are spread out evenly over time – even if that means higher rates"* and 43% said *"Enersource should spend only what is needed to maintain system reliability – even if that means from year to year there may be fluctuations in the rate of capital investment."*

In total, 82% of Enersource RZ Residential customers believe that some form of investments should be made in order to maintain reliability.

Similarly, in the statistically significant telephone surveys, customer support ranges from 57% to 65% in support of replacing aging infrastructure, even if that increases monthly electricity bills by a few dollars over the next few years.

Considering the customer feedback from both engagement activities, it appears that Enersource RZ customers place a high degree of emphasis on replacing aging infrastructure. The representative customer sample from the telephone surveys confirms the feedback that was initially gathered through the Online Feedback Portal.

b) While "delivering reasonable distribution rates" is a top priority for most customers in the Enersource RZ, replacing aging infrastructure and maintaining reliability remained important considerations throughout the Customer Engagement process. In fact, when presented with the proposed Enersource RZ investment plan in the Online Feedback Portal, only 8% of Residential customers selected the following option with regards to the Enersource RZ forecasted plan for replacing aging infrastructure:

Question D3 - Thinking about Enersource's forecasted plan for replacing aging infrastructure, which of the following statements best represents your point of view?

Enersource should focus on keeping rates as low as possible in the near-term and only spend the bare minimum on replacing aging infrastructure – even if that means higher replacement costs in the future.

[Appendix 5.0, Alectra Utilities' Online Feedback Portal Layout, Question D3, Page 28]

Based on this feedback, it appears that customers in the Enersource RZ believe that Alectra Utilities' should spend at least what is needed to maintain reliability in order to not incur higher replacement costs in the future.

ERZ-Staff-36

Large Use Customer Feedback on Enersource's ICM Projects

Reference(s): E3/T1/S1 – Innovative Customer Engagement Report, Page 24

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.

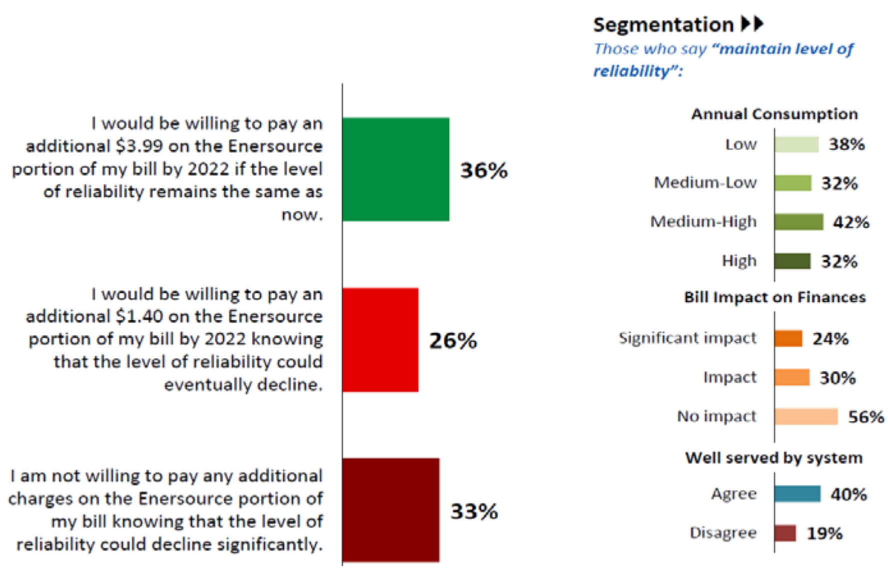
Response:

a) Alectra Utilities' regularly engages with Large Use customers as part of ongoing customer service efforts. With reference to Appendix 3.0 – Enersource Large Use Online Survey Report, 6/7 customers agreed that "Enersource staff are easily accessible to my organization", with the remaining customer neither agreeing nor disagreeing. Additionally, the online survey provided Large Use customers with the opportunity to anonymously provide additional comments or feedback to share with Alectra Utilities'. Of the seven Large Use customers in the Enersource RZ, three respondents provided additional comments, none of which referred to the desire to receive additional information on the proposed rate increase in 2018.

ERZ-Staff-37

Reference(s):_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?

Response:

a) In principle, most customers indicate some level of support for investment in system renewal, general plant, system service and modernizing the distribution system. However, when it comes to financing these investments, many customers pushback when they further understand the potential impacts on their distribution rates.

Pages 17-20 demonstrate that Residential Enersource RZ customers believe that, in principle, investments should be made to maintain reliability. The results on page 21 demonstrate that 62% of these customers are willing to pay more (i.e. between $1.40 and

$3.99) for these proposed investments. However, as demonstrated throughout the engagement, rate frustration appears to be a primary driver of customer pushback.

b) Please see section 3.1.6 Customer Engagement Activities (5.4.1.f) of Alectra Utilities' Distribution System Plan for the Enersource RZ (Exhibit 3, Tab1, Schedule 1, p. 285) for an overview of the customer engagement efforts and detailed explanation on how customer feedback and preferences have been reflected the five year capital investment plan for the Enersource RZ. Based on customer priorities and preferences, deferral and pacing of expansion-related projects were incorporated over the 2017 to 2022 investment period. The total impact of these adjustments, is a reduction of $6.81MM over the forecast period.

ERZ-Staff-38

Reference(s): 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?

Response:

ai) Table 1 below provides a ranked list of proposed ICM projects for the Enersource Rate zone. The table must be understood in the context of Alectra Utilities' Asset Management Practice and Capital Investment Plan Optimization process. Pursuant to this process, Alectra Utilities' evaluates each project in the capital investment plan, to pace and prioritize investments based on business values, objectives and risks. The portfolio of projects presented, that is, those in Table 144 of the Alectra Utilities' DSP for the Enersource RZ, reflect prudent investment needs and the most cost effective option for ratepayers. They are all necessary and produce positive outcomes for ratepayers.

Table 1: Ranked List of Proposed ICM projects for the Enersource Rate Zone

Rank	Project
1	Road Widening Project – QEW (Evans to Cawthra)
2	Leaking Transformer Replacement Project
3	Substation Upgrade – York MS
4	Subdivision Rebuild - Glen Erin & Battleford
5	Subdivision Rebuild – Glen Erin & Montevideo
6	Subdivision Rebuild – Credit Woodlands Crt/Wiltshire
7	City Centre Drive Cables

8	Tenth Line Main Feeder
9	Folkway & Erin Mills Main Feeder
10	Overhead Rebuild – Church
11	Overhead Rebuild - Lake/John

a ii) Not applicable. Please see Alectra Utilities' response to part a i), above.

a iii) In the event the OEB were to approve only a portion of the ICM expenditure, Alectra Utilities' would have to consider that decision at the time along with any further direction provided by the OEB in that decision. It would also have to consider its existing circumstances in the Enersource RZ. Alectra Utilities' cannot say today, beyond the first two projects, both of which are deemed mandatory, whether the ranking following receipt of the Decision would be the same as set out above.

b) Yes, Alectra Utilities' has considered deferring lower priority projects. As part of the Asset Management Practice and Capital Investment Plan Optimization processes, Alectra Utilities' has evaluated each project in the capital investment plan to pace and prioritize investments, based on business values, objectives and risks. The portfolio of projects presented, which also includes the projects listed in Table 144 (E2/T4/S11/Page31) in the Alectra Utilities' DSP for the Enersource RZ, incorporates prudent investment needs and the most cost effective option for ratepayers.

c) Alectra Utilities' has not incorporated any allowances or placeholders for unanticipated system access investments in the Enersource RZ.

d) A description of each of the project's need and prudence is included in the Application at Exhibit 2, Tab 4, Schedule 11, beginning at page 33. The project-related business cases for the Enersource Rate Zone are found in Attachment 47. Drivers of the projects are provided in Table 2, below

Table 2: Proposed ICM Projects and Primary Drivers

Project	Driver
Road Widening Project – QEW (Evans to Cawthra)	Enersource Hydro Mississauga became aware of the preliminary scope and timing of project upon the release of the

	Transportation Environmental Study Report in January 2016, hence the scope and timing of the project was not known to Enersource in 2013.
Overhead Rebuild - Lake/John	Through its recent 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) that were not known in 2013.
Overhead Rebuild - Church	
Leaking Transformer Replacement Project	Through rigorous inspections in 2013 to 2016, a large number of transformers were found to exhibit signs of oil leaks or contain PCB, which could lead to significant liabilities, in the event of spills. The scope and volume of the number of transformers that require replacement was not known in 2013. The project scope which is based on the backlog of transformers to be replaced was known in January 2017. Additional details are available in Exhibit 2, Tab 4, Schedule 11, p. 43.
Subdivision Rebuild - Credit Woodlands Crt/Wiltshire	From 2014 to 2016, increasing failures on early generation underground cables are leading to a rising numbers of outages, having an adverse impact on reliability.
Subdivision Rebuild - Glen Erin & Montevideo (Section 1)	
Subdivision Rebuild - Tenth Line Main Feeder	
Subdivision Rebuild - Folkway & Erin Mills Main Feeder	
Subdivision Rebuild - Glen Erin & Battleford	
City Center Driver Rebuild	Inspections completed in 2016 identified

	problems with the underground infrastructure that were not known in 2013. The issues with the underground infrastructure include rusted lids, spalling of the concrete, access restrictions and separation of foundation. More details can be found in Attachment 47 in pages 36 to 43.
Substation Upgrade – York MS	Station capacity upgrade and equipment renewal is required to address growth in the area. Reliability issues associated with cable egress and substandard station protection configuration are also driving this renewal. The project is required in 2018 to address growth and sub-standard equipment and configuration. Details can be found at Exhibit 2, Tab 4, Schedule 11, p. 45.

e) Alectra Utilities' capital investment plan includes both underground cable and transformer replacement programs. For underground cable, Alectra Utilities' investment plan includes the Underground System Distribution Renewal & Sustainment program, as well as the Emergency Replacement Program. Investment requirements for both programs are provided in Table 51 in the Alectra Utilities' ERZ DSP, at Exhibit 3, Tab 1, Schedule 1, p.260. Further, Table 52 provides the breakdown of proactive discrete projects with adequate design and scheduling consideration from reactive and ad hoc replacements due to equipment failure as well as emergency replacement due to external influences such as vehicle accidents.

For the transformer replacement program, Alectra Utilities' investment plan includes the both an Underground Transformer & Equipment Renewal as well as Overhead Transformer & Equipment Renewal program. 2017-2022 investment requirements for both programs are listed in Table 55 in the Alectra Utilities' DSP for the Enersource RZ (Exhibit 3, Tab 1, Schedule p.274-275). Where the multi-year project to replace the backlog of transformers exhibiting signs of oil leaking, the transformer replacement program address the investment needs to replace damaged, faulted as well as rusted transformers on a reactive basis.

The transformer replacement project is different from the transformer replacement program in that the project addresses a backlog of known transformer found to exhibit signs of leaking where the transformer replacement program addresses immediate need to replace damaged, faulted and rusted transformers that pose a safety hazard to employees and the public.

Each 2018 underground system renewal project was reviewed as part of the Asset Management Practice and Capital Investment Plan Optimization processes. Alectra Utilities has evaluated each renewal project in the plan to pace and prioritize investments based on business values, objectives and risks. All underground system renewal projects were determined to be required and were prioritized for 2018 implementation. Further, the list of 2018 underground projects presented in Table 55 found in the Alectra Utilities DSP for the Enersource RZ reflects prudent investments needs and the most cost effective option for ratepayers.

Some of the underground cable rebuilds proposed for ICM are evaluated higher priority and some are evaluated to be lower priority to other underground cable rebuilds in base capital based on the Enersource rate zone project prioritization evaluations.

f) As part of the Asset Management Practice and Capital Investment Plan Optimization processes, Alectra Utilities has evaluated each renewal project in the capital investment plan to pace and prioritize investments based on business values, objectives and risks. The portfolio of renewal projects presented, in the Alectra Utilities' (Enersource Rate Zone) DSP reflects prudent investments needs and most cost effective option for ratepayers. Alectra utilities incorporated customer input into the capital investment plan, customer feedback identified a preference for system renewal over system expansion through the pacing and deferral of $6.8MM of expenditures over the capital investment forecast period.

ERZ-Staff-39

Reference(s): 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.***

Reference(s): 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?**

Response:

a) This project does not involve transformer upgrades. The transformer replacement project is a multi-year capital project to replace transformers that have been identified as showing signs of oil leaks and/or containing PCBs, in a well-planned and paced manner until 2021.This multi-year project addresses the remaining backlog of 2,244 transformers requiring timely replacements. This project has a unique scope, budget and end date. The statement as provided in evidence was a typo that should have stated:

"Each project is distinct, unrelated to recurring annual capital **program**, and has been evaluated in the asset management and capital planning process as required in 2018." (Emphasis added)

b) In order to be eligible for incremental capital, an ICM claim must satisfy the eligibility criteria of materiality, need and prudence. The leaking transformer replacement project exceeds Alectra Utilities' project materiality threshold of $589,950 for the Enersource RZ. The OEB applies the Means Test to assess the need for the ICM project. The Means Test states that if a distributor's regulated return exceeds 300 basis points above the deemed ROE, the funding will not be allowed. The ROE for the Enersource RZ was calculated to be 6.13%, 280 basis points below its approved ROE of 8.93%. Please see part a) of the response which addresses the discrete nature of the project, which is unrelated to a recurring annual capital program. This project has been evaluated in the asset management and capital planning process and represents the most cost effective option for rate payers.

ERZ-Staff-40

Reference(s): 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.**

Response:

The method used to calculate the SAIDI for each subdivision is based on the total customer minutes of outage for all outages which the transformers in the rebuild area was affected by divided by the number of customers in the rebuild area.

a) The SAIDI and SAIFI results for the Glen Erin and Battleford rebuild areas are provided in the table below

Year	2011	2012	2013	2014	2015	2016
SAIDI (minutes)	1053.41	526.28	289.90	27.44	797.72	2361.65
SAIFI	34.23	66.16	21.32	12.56	87.70	48.04

b) i) The SAIDI and SAIFI results for the Glen Erin and Montevideo rebuild area is provided in the table below.

Year	2011	2012	2013	2014	2015	2016
SAIDI (minutes)	79.42	11.06	305.11	256.85	189.39	798.83
SAIFI	2.78	0.14	3.59	2.68	3.70	4.68

ii) The SAIDI and SAIFI results for the Credit Woodlands and Wiltshire rebuild area is provided in the table below..

Year	2011	2012	2013	2014	2015	2016
SAIDI (minutes)	14.55	56.17	78.83	0.00	56.00	94.60
SAIFI	1.89	1.28	0.88	0.00	5.00	2.23

iii) The SAIDI and SAIFI results for Tenth Line Main Feeder rebuild is provided in the table below.

Year	2011	2012	2013	2014	2015	2016
SAIDI (minutes)	8.15	33.98	4.01	23.16	63.83	21.26
SAIFI	0.81	2.91	1.38	4.51	5.31	5.55

iv) The SAIDI and SAIFI results for Folkway & Erin Mills rebuild is provided in the table below.

Year	2011	2012	2013	2014	2015	2016
SAIDI (minutes)	87.75	197.72	119.23	90.89	581.89	218.56
SAIFI	4.11	9.69	11.55	4.77	25.02	7.26

v) The SAIDI and SAIFI results for City Centre Drive rebuild is provided in the table below. This project was selected based on the condition of the civil infrastructure and the age of the cables not the cable failure history.

Year	2011	2012	2013	2014	2015	2016
SAIDI (minutes)	0.00	0.00	0.00	0.00	0.00	0.00
SAIFI	0.00	0.00	0.00	0.00	0.00	0.00

c) i) In addition to the subdivision rebuild projects included in the ICM request, the following subdivisions are also included in the 2018 Capital Forecast:

- Gananoque Section 1
- Boughbeeches Section 1
- Copenhagen Section 1
- Appledore Section 1

ii) The needs and drivers of the ICM projects are similar to those in based capital. What Alectra Utilities has determined is that all these projects are required, there is not sufficient capital in base revenue and therefore an ICM is required. Please see response to BOMA 112 (aii) for details on how the ICM projects rank to base capital projects.[

iii) The SAIDI and SAIFI for the Appledore rebuild area is provided in the table below..

Year	2011	2012	2013	2014	2015	2016
SAIDI (minutes)	82.97	99.54	140.14	100.59	162.63	179.78
SAIFI	10.40	20.10	10.34	11.44	14.68	19.58

The SAIDI and SAIFI for the Gananoque rebuild area is provided in the table below..

Year	2011	2012	2013	2014	2015	2016
SAIDI (minutes)	220.47	167.98	225.44	448.42	24.41	336.46
SAIFI	7.65	7.55	11.75	7.28	3.99	16.37

The SAIDI and SAIFI for the Copenhagen rebuild area is provided in the table below.

Year	2011	2012	2013	2014	2015	2016
SAIDI (minutes)	45.41	5.95	58.81	49.06	103.78	499.61
SAIFI	11.42	3.31	23.48	17.06	15.56	15.53

The SAIDI and SAIFI for the Boughbeeches rebuild area is provided in the table below.

Year	2011	2012	2013	2014	2015	2016
SAIDI (minutes)	61.31	58.92	252.97	307.85	235.20	331.75
SAIFI	15.60	16.30	24.07	25.01	30.05	44.40

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Reference(s): E2/T4/S11, p.41-42

At the above reference, the following statement is made:

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

Project Description and Drivers

- ***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.***

Project Description and Drivers

- ***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.***

Church St. Area Overhead Rebuild
System Renewal: $1.02MM

Project Description and Drivers

- ***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.***

Project Description and Drivers

- ***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?

Response:

a) There were no pole failures during that period. However, there was a reliability impact in the Lake/John area from a failed insulator that resulted in a fallen wire, which posed a public safety concern. Alectra Utilities takes a proactive approach to replacing poles in poor condition due to worker and public safety concerns.

b) Pole related failures are not currently causing an exceptional level of outages. Poles in poor condition may result in failure and lengthy outages compared to proactive replacement.

c) Common reasons for premature failure of wood poles include:
- Surface and/or internal rot
- Major Cracks to ground line
- Insect infestation
- Mechanical damage
- Hollow heart, voids

One or more of the conditions above will result in a lower condition score from the pole inspection maintenance program. The business cases for Lake/John (Exhibit 3, Tab 1, Schedule 1, Attachment 47, p.44) and Church St (Exhibit 3, Tab 1, Schedule 1, Attachment 47, p.51) identify that poles in these areas have some of the above mentioned conditions.

d) i) Yes, there are other areas with similar conditions and vintages in the Enersource RZ. Enersource began resistograph testing of wood poles in 2015. The poles in the Lake/John and Church St areas were some of the first poles tested, and which failed resistograph testing. Due to the condition of these assets, these areas were prioritized as rebuild areas in the City of Mississauga.

ii) Alectra Utilities' would not consider these projects for deferral due to the risk to worker and public safety, not solely due to the condition of the poles, but also based on other factors including but not limited to:
- Pin-top or EPAC insulators, which can result in pole fires or falling wires;
- Cut ground wires, which impacts worker safety; and
- Open bus secondary, which is a safety risk to both workers and the public

These are also discussed in the Lake/John and Church Street business cases.

ERZ-Staff-42

Reference(s): E2/T4/S11, p.43-44

At the above reference, the following statement is made:

> ***Transformer Replacement Project***
> ***System Renewal: $8.45MM***
> ***Project Description and Drivers***
> - ***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?

Response:

a) Starting in 2013 Alectra Utilities' inspection methodology in the Enersource RZ was changed to capture improved condition parameters. The transformer inspection practice was updated to include opening of the transformer door and to inspect the internal components of the device where deemed necessary by the inspector. This method of inspection provided greater detail regarding the internal condition of oil containment features, levels of corrosion and cable and connection issues. The transformers replaced were still in service and providing electrical supply to customers; however, the oil containment features were jeopardized and the transformers were found to be leaking oil into the environment. The response was carried out in proactive manner to mitigate environmental contamination and to minimize the cost of remediation and loss of enjoyment of property by Alectra Utilities' customers.

b) The transformer inspection practice implemented in 2013, resulted in more detailed and comprehensive transformer condition data. Prior to this, only external inspections were performed, which revealed external oil leaks, but did not indicate oil leaking from the internal compartment. The improved inspection process was initiated after replacing units and finding major oil contamination in the transformer foundation, which was not evident from the external inspection.

c) $5.6M in environmental remediation costs were treated as expense at the time when it was determined that the liability existed to remediate the contaminated sites.

d) The information provided in table 67 (correction to reference - Table 67 on pg. 342) of the DSP includes costs of overhead and underground transformer replacements from oil leaks at 103 sites, totaling $19.4 MM; the annual overhead and underground transformer replacement program totaling $7.9 MM; and the cost of spare transformers totaling $8.8MM.

e) The percentage of leaking in-service transformers at the end of 2016 was approximately 8.3%.

   i. This value has declined since 2013 by approximately 4.3 as a result of the replacement of leaking transformer's completed from 2013 to 2016.

f) Other problematic transformers refer to units found after January 1, 2017, where the transformer is damaged from vehicle collisions, compromised from an oil containment perspective or from a public safety perspective. This includes conditions where corrosion has advanced to a degree such that the transformer is leaking oil, where the locking mechanism is no longer secure, or where corrosion has advanced to a degree on the access door or skirt such that the high voltage and low voltage components are no longer secure from tampering or probing. These transformers are evaluated and replaced under the on-going annual reactive replacement program as they are found and as a result they cannot be treated in a pre-emptive manner.

g) The transformer ICM project constitutes a project designed to replace the backlog of transformers identified from the 2013 to 2016 inspections. These 2244 transformers are a fixed base of units that were identified in previous years and remain in service as of Dec 31, 2016 constituting the backlog project.

The reference to "base capital PCB & Leaking Transformer Replacement Project" relates to the annual transformer replacement program and is not deemed a project. It is an ongoing program intended to address transformers found defective or no longer suitable for service due to public safety concerns due to physical damage, corrosion, oil leaks or faulted windings and irreparable bushing inserts after January 1, 2017. This annual program is not limited to PCB and leaking transformers only.

.

h) Please see Alectra Utilities' response to part g).

ERZ-Staff-43

Reference(s): 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.

Response:

a) Table 145 summarizes the ICM revenue requirement calculation. Alectra Utilities' relied on the Board's Capital Module Applicable to ACM and ICM ("Capital Module") to calculate the incremental revenue requirement. The detailed calculation can be found in Tab 11. Incremental Capital Adj of the Board's Capital Module, filed as Attachment 45, and reproduced below. The calculation is consistent with the Board's Model.

Incremental Capital Adjustment

Current Revenue Requirement					
Current Revenue Requirement - Total			$	117,989,982	**A**

Return on Rate Base					
Incremental Capital			$	24,247,022	**B**
Depreciation Expense			$	589,204	**C**
Incremental Capital to be included in Rate Base			$	23,657,818	**D = B - C**
Deemed ShortTerm Debt %	4.0%	**E**	$	946,313	**G = D * E**
Deemed Long Term Debt %	56.0%	**F**	$	13,248,378	**H = D * F**
Short Term Interest	2.08%	**I**	$	19,683	**K = G * I**
Long Term Interest	5.09%	**J**	$	674,342	**L = H * J**
Return on Rate Base - Interest			$	694,026	**M = K + L**
Deemed Equity %	40.00%	**N**	$	9,463,127	**P = D * N**
Return on Rate Base -Equity	8.93%	**O**	$	845,057	**Q = P * O**
Return on Rate Base - Total			$	1,539,083	**R = M + Q**

Amortization Expense					
Amortization Expense - Incremental		**C**	$	589,204	**S**

Grossed up PIL's					
Regulatory Taxable Income		**O**	$	845,057	**T**
Add Back Amortization Expense		**S**	$	589,204	**U**
Deduct CCA			$	1,895,165	**V**
Incremental Taxable Income			-$	460,904	**W = T + U - V**
Current Tax Rate	26.5%	**X**			
PIL's Before Gross Up			-$	122,140	**Y = W * X**
Incremental Grossed Up PIL's			-$	166,176	**Z = Y / (1 - X)**

Incremental Revenue Requirement					
Return on Rate Base - Total		**Q**	$	1,539,083	**AA**
Amortization Expense - Total		**S**	$	589,204	**AB**
Incremental Grossed Up PIL's		**Z**	-$	166,176	**AC**
Incremental Revenue Requirement			$	1,962,111	**AD = AA + AB + AC**

1

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Reference(s): E2/T4/S11, p.49

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

Rate Class	Unit	kWh	kW	ICM Rate Rider incl. HST	% 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%

Reference(s): 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.

Response:

a) 'Total Bill' in Table 148 includes energy and transmission and global charge. Further, the 'Total Bill includes the distribution delivery component, taxes and the 8% provincial rebate.

b) The factors that were included when calculating the bill impacts shown in Table 149 are: monthly service charge; distribution volumetric rate, ICM rate rider and the LRAMVA rate rider. The Distribution Bill Impacts correspond to 'Sub-Total A (excluding pass through) on Tab 21. Bill Impacts of Attachment 39, IRM Model Enersource RZ.

The bill impacts in Table 148 were calculated by dividing the proposed ICM bill amount for each rate class, determined by multiplying the ICM rate rider by the respective kWh or kW consumption/demand value, inclusive of HST and the 8% provincial rebate, where applicable, by the total current bill for each rate class as shown on Tab 21. Bill Impacts of Attachment 39 IRM Model Enersource RZ.

ERZ-Staff-45

Reference(s): 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.**

Response:

a) The $6.81MM adjustment is the total net reductions over the 2017 to 2022 period from pacing and deferral adjustments that incorporate customer priorities and preferences, including the deferral of the Webb MS ICM project. The 2018 maximum eligible incremental capital or base capital envelope, presented in Table 136 (Exhibit2/Tab4/Schedule 11 pg. 24) of the Application, of $39,624,419 was calculated based on a 2018 capital forecast of $83,118,772, before incorporating customer preferences, and a materiality threshold of $43,494,353. The 2018 portion of the $6.81MM adjustment is $5.89MM. As stated in Alectra Utilities' response to ERZ-Staff-29, the 2018 capital forecast adjustments includes pacing adjustments to 2018 project expenditures that include both Webb MS and as well as other distribution capital investments.

As stated in the above reference, the capital forecast in the DSP was driven by growth in various areas of Mississauga, infrastructure projects, aging infrastructure and environmental concerns. Alectra Utilities' incorporated customer preferences from customer engagement, and paced and deferred investments during the 2017 to 2022 period based on customer feedback.

b) The magnitude and rate of asset deterioration was not fully known in 2012. With the implementation of a formal asset management practices, Alectra Utilities' predecessor, Enersource made improvements to asset inspection programs and data collection, including more frequent and detailed inspections, more rigorous review of outage data and the use of additional analytical methods.

From 2014 to 2016, Enersource RZ has experienced an increasing number of underground cable failures as illustrated in Figure 2 of E2/T4/S11 Page 12. In order to address this increasing trend of underground cable failures, Alectra Utilities' utilizes an analytical method to map overlay maps using data attained from the outage management system to identify and target the worst performing areas of the system (i.e. with multiple historical failure, cable types that are prone to failure, and potential need to concurrently renew other assets). The enhanced analytical methods used to provide the overlay map of the worst performing areas of the system is illustrated in Figure 3 of E2/T4/S11 Page 13.

There has been an increase in the failure involving magnetic air circuit breakers (two failures in the past 15 months) and given the scarcity of spare parts as well as risk of asbestos in arc chutes, Alectra Utilities has put in plans to renew certain substation assets over the DSP plan period. Details regarding substation asset renewals are described in detail in Section 3.5.2.3.1.2 Substation Upgrades of the Alectra Utilities DSP for the Enersource RZ (E3/T1/S1).

In 2014 and 2015, Alectra Utilities' predecessor, Enersource completed a full inspection of the entire overhead distribution system. In addition, a pole testing program was also introduced to provide supplementary inspection information on the condition of wood poles. Data from the inspection program improved the granularity of information and was utilized in the calculation of the health index in the asset condition assessments. Similar to the overlay analytical methodology utilized for underground system assets, Alectra Utilities uses an overlay methodology to address the worst performing areas of the overhead system as illustrated in Figure 4 of E2/T4/S11 Page 14.

ERZ-Staff-46

Reference(s): E3/T1/S1/A50, p.7-8

At the above reference, the following statement is made:

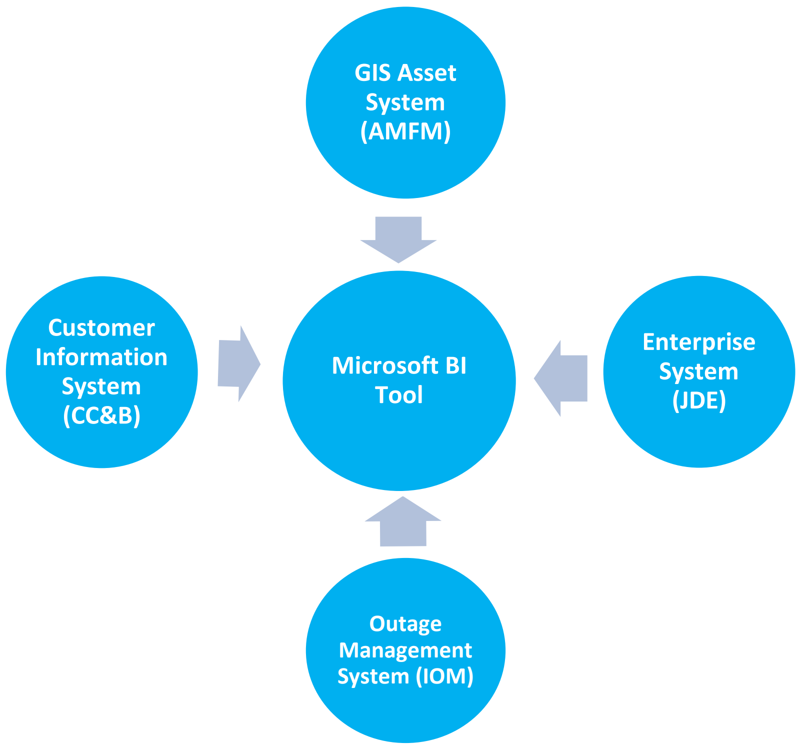
> ***5) Asset Management***
>
> ***Alectra Utilities believes that by continuously improving its asset management practices and procedures, its ability to ensure reliable distribution system performance will be enhanced while overall costs and rate impacts will be more effectively controlled. In this 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?**

Response:

a) Asset Management requires leveraging relevant data to support analysis and decision making. For Alectra Utilities', this includes data from 4 distinct and different systems in the Enersource RZ. These systems include Geographical Information System ("GIS"), Integrated Operating Model ("IOM") (outage management system), JD Edwards ("JDE")/Enterprise Resource Planning ("ERP") system JDE (ERP) and Customer Information System ("CIS"). A Business Intelligence (BI) solution facilitates ease of collection of data from these 4 separate systems in a digital format, compiling all relevant information needed to perform a multitude of analytic operations in support of asset management. The BI solution reduces the amount of manual effort required to source data.



b) Once assembled in a central data warehouse, a BI solution can reveal patterns and trending through the use of analytics. The BI solution reduces the amount of manual effort required to source data. The asset management decisions in the Enersource RZ DSP is based on several inputs, including customer preferences ascertained through engagement activities, asset health condition assessment, system load forecast, asset information from testing and inspection reports, as well as information from certain major information technology tools which include the Outage Management System ("OMS"), GIS, JDE/ ERP system, and CCIS.

ERZ-Staff-47

Reference(s): 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.

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

Response:

a) Alectra Utilities' utilizes Asset Condition Health Index data as an essential input in its process and leverages subject matter expertise in developing its project portfolio and business cases. Further, Alectra Utilities' completes an analysis of expected failures, risks and consequences and incorporates a replacement strategy that considers potential synergies among asset types being replaced.

b) Prioritization of the project portfolio and optimization and pacing of investment is described in sections 2.1.2.1.5 (pages 81-82) and 2.1.2.2 (page 83) of the DSP, respectively.

ERZ-Staff-48

Reference(s): 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?**

Response:

The OM&A savings projected for each year of the planning period of the DSP, were estimated in the project business cases for renewal investments as well as replacement of specific general plant assets. Alectra Utilities estimates approximately $300,000 in annual OM&A savings from system renewal investments as well as $110,000 in OM&A savings from replacement of specific general plant assets in the Enersource RZ.

System Access

As system access investments relate to upgrades of the distribution system necessary to provide access to electrical service for customers as well as asset relocations for road widening, there are no estimated OM&A savings associated with such investments.

System Renewal

The projected $300,000 in annual OM&A savings are attributed to timely system renewal investments related to underground system rebuilds, overhead system rebuilds as well as investments in sub-transmission renewals. The savings are projected for each year of the planning period of the DSP and were estimated in the project business cases for renewal investments. The annual savings were estimated based on the reduction to emergency replacements of failures, reduction in overtime costs, reduced emergency generator costs as well as other miscellaneous repair expenses. The capital costs associated with these investments is listed in Table 1.

Table 1: 2017-2022 System Renewal Expenditures for Underground, Overhead and Substransmission Assets

Description	2017 ($000)	2018 ($000)	2019 ($000)	2020 ($000)	2021 ($000)	2022 ($000)
Subdivision Renewal	13,802	16,102	17,252	18,502	18,502	18,502
Overhead Distribution Renewal and Sustainment	5,268	6,492	7,032	7,032	7,032	7,212
Subtransmission Renewal	3,736	3,736	3,286	3,436	4,186	4,786
Total	22,806	26,330	27,570	28,970	29,720	30,500

<u>System Service</u>

System service investments are upgrades to the distribution system to ensure that the system continues to meet operational objectives as well as addressing anticipated future customer electricity service requirements. There are no estimated OM&A savings associated with such investments.

<u>General Plant</u>

The projected $110,000 in annual savings were estimated on the reduction to unplanned fleet repair costs, reduction in building facility repair costs and certain energy efficiency initiatives to reduce facility operating costs and waste. The capital costs associated with these investments is listed in Table 2.

Table 2: 2017-2022 System Renewal Expenditures for Rolling Stock and Grounds & Buildings

Description	2017 ($000)	2018 ($000)	2019 ($000)	2020 ($000)	2021 ($000)	2022 ($000)
Rolling Stock	2,427	2,520	2,796	3,101	2,428	1,887
Grounds & Buildings	2,855	2,400	3,325	3,575	3,050	2,295
Total	**5,282**	**4,920**	**6,121**	**6,676**	**5,478**	**4,182**

iii) As the savings are projected for each year of the planning period of the DSP and were estimated in the project business cases for renewal investments as well as replacement of specific general plant assets, project reviews are completed to verify that all projects outcomes including expected OM&A savings are realized.

ERZ-Staff-49

Reference(s): 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?

Response:

a) Alectra Utilities' identified 2,074 leaking transformer locations, (Table 74, page 371 of the DSP). If these transformers remain in service the oil leak will continue to degrade and the environmental impact will increase. The scope of environmental remediation increases proportionally to the degree of oil that has spilled. Alectra Utilities' transformer replacement program has identified the number of transformers that will need to be replaced in the Enersource RZ.

b) During the period from 2012 to 2016 Alectra incurred $5.6MM in environmental remediation costs. All costs associated with this effort were mapped to specific work orders which were then analyzed to establish an average remediation cost of $50,000 per site.

ERZ-Staff-50

Reference(s): 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?

Response:

a) The Capital Investment Plan is developed based on Asset Management processes that require business case development for each project, which describe defined outcomes and justify the project cost estimates. As identified in Figure 19 – Asset Management Flow Diagram in Alectra Utilities' DSP for the Enersource RZ(E3/T1/A50A Page 76), a prudency review of each discretionary investment is undertaken to ensure investment levels are appropriate.

b) Alectra Utilities' does not have a policy for setting contingency for capital investments in the Enersource RZ. The approach taken is to estimate project costs as accurately as possible based on known information at the time of business case development. Internal monitoring and controls of capital expenditures are in place to ensure cost efficiency.

ERZ-Staff-51

Reference(s): 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?

Response:

a) The increase in SAIDI during the 2011 and 2012 period was related to higher than normal equipment failures from cable faults, splices and overhead equipment as shown in Table 9 of Alectra Utilities DSP for the Enersource RZ (E3/T1/S1/A50, pg.66). The causes of the relatively high SAIDI during 2011-2012 are provided in Alectra Utilities response to ERZ-Staff-54 b).

b) The reduction was primarily due to external factors. The number of cable failures is correlated to loading which is dependent on weather conditions. As cables continue to age the stress of high loading will continue to cause failures until older vintage (non-TR-XLPE) cables are replaced.

c) Alectra Utilities DSP for the Enersource Rate Zone proposes an increase in subdivision rebuilds to improve localized SAIDI levels while maintaining SAIDI at a system level.

ERZ-Staff-52

Reference(s): 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.

Response:

In 2015, six general plant projects were delayed due to the proposed merger. These included Asset Management Software ($0.27 MM), HR Performance Tool ($0.05 MM), CC&B Customer Web Self Service ($0.221 MM), Primeread IMS Synchronization ($0.08 MM), Mavis Kitchen & Women's Locker Room ($0.55 MM), and the Mavis Building Envelope ($0.3 MM).

In 2016, general plant capital investments related to rolling stock ($2.455 MM), computer equipment renewal ($ 0.474 MM), Enterprise Resource Planning (ERP) system ($2.110 MM), Customer Information System (CIS) development ($2.470 MM) as well as investment in Grounds & Building ($ 0.980 MM) were deferred.

None of the deferred general plant investments were included in the incremental capital funding request.

Investments related to rolling stock and grounds & building have been incorporated, paced and prioritized into the 2018-2022 capital investment plan.

Investments related computer equipment renewal, ERP system and CIS development initially planned by Enersource as a stand-alone utility will instead be evaluated, prioritized and executed by Alectra Utilities' as a consolidated entity. As a result, these investments are no longer specific to the Enersource rate zone and therefore have been excluded from the Alectra Utilities' (Enersource Rate Zone) DSP and investment plan.

ERZ-Staff-53

Reference(s): E3/T1/S1/A50, p.62

Figure 12 - Per-Unit Cost of Transformation Installation

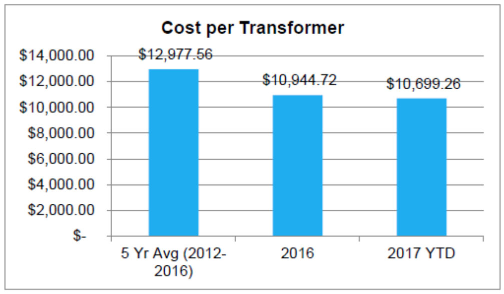
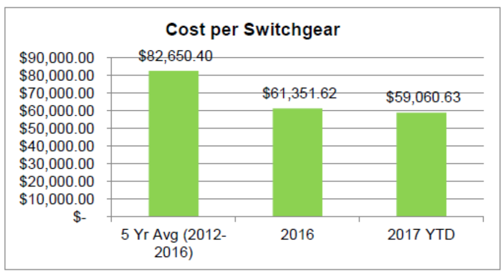


Figure 13 - Per-Unit Cost of Switchgear Installation



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

Response:

Transformer & Switchgear savings were attained primarily due to lower contractor costs. These savings are attributable to the efficiencies realized due to grouping or bundling of transformers and/or switchgear installation from a scheduling standpoint, made possible by the Outage Management System (OMS) that was implemented in early 2016. Historically, equipment was replaced based on priority. Currently, transformer and switchgear replacements in a particular area are grouped and worked on concurrently resulting in savings in contractor costs.

ERZ-Staff-54

Reference(s): 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

Response:

a) The trend of decreasing failures for underground cables is primarily due to external factors. Underground cables tend to fail during high loading which is consistent with persistent hot temperatures. During hot summers, the probability of failure increases due to additional loading on the system which stresses the aged cables. For example, in 2016, Mississauga along with GTA experienced persistent hot weather that led to a record number of underground cable failures in the Enersource RZ.

b) i) The decreasing trend being referred to for overhead equipment from 2011 to 2016 is due to a single event increasing the 2011 values. In 2011 a pole came down which resulted in a significant outage of about 550,000 customer minutes. In 2016, there were no significant overhead equipment outages.

ii) The decreasing trend in splice failures is the result of an anomaly in 2012. In 2012, the Enersource RZ experienced 3 major splices failures on main feeder cables that resulted in an outage duration of approximately 600,000 customer minutes. Further, the majority of heat shrink splices in poor condition failed prior to 2015.

iii) The decreasing trend in switch failures is due to a lower number of failures during 2015 and 2016. In 2012, a switch failure resulted in approximately 200,000 customer minutes of outage. In 2013, 3 switches failures resulted in approximately 150,000 customer minutes of outage. In 2014, 1 switch failure resulted in approximately 200,000 customer minutes outage.

ERZ-Staff-55

Reference(s): 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.**

Response:

Alectra Utilities' does not rate public safety concerns on a scale when using the number of Public Safety Concerns to assess trends in asset and system performance.

ERZ-Staff-56

Reference(s): 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.**

Response:

'Greatest impact' is determined by a project score, derived from quantifiable inputs incorporated into project business cases. Capital projects are scored by identifying their risks and benefits as they relate to business values through the use of the project evaluation criteria outlined in Tables 25 to 27 in Section 2.1.2.11 of the Alectra Utilities' DSP for the Enersource RZ (E3/T1/S1/A50, Pages 113 to 115). Examples of scoring on business values for each project can be found in each business case in Appendix E – Business Cases of Alectra Utilities' (Enersource Rate Zone) DSP (E3/T1/S1/Attachment 50, Page 403).

For a detailed explanation on the project scoring methodology in the Enersource RZ please refer to response to BOMA 112. For a breakdown of the scoring criteria, please refer to response to ERZ-Staff-22.

ERZ-Staff-57

Reference(s): E3/T1/S1/A50, p.91

At the above reference, the following statement is made:

> ***<u>Switchgear</u>***
>
> ***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.

Response:

a) 29% of units (170/587) have reached end-of-life.

b) For this particular reference, switchgear failure is a flashover or catastrophic/explosive failure resulting in loss of functionality of one or more switch positions.

c) The primary consequence associated with switchgear failure is a customer outage. There may be customers with radial supplies (no second supply) from the switchgear that would remain out if it was not replaced. In other circumstances switchgear can be isolated from the system but with these units not in service it would reduce the operational switching flexibility should further outages occur, i.e. the system would be in an N-1 state, which means that one supply in a loop is no longer available so only 1 supply remains. Systems are generally only built to N-1 so further outages may result in customers being out of power for an extended period of time.

ERZ-Staff-58

Reference(s): 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?**

Response:

As described in response to ERZ-Staff-56, capital projects are scored by identifying their risks and benefits as they relate to business values through the use of the project evaluation criteria outlined in Tables 25 to 27 in Section 2.1.2.11 of the Alectra Utilities' DSP for the Enersource RZ (E3/T1/S1/A50, Pages 113 to 115). Examples of scoring on business values for each project can be found in each business case in Appendix E – Business Cases of Alectra Utilities' (Enersource Rate Zone) DSP (E3/T1/S1/Attachment 50, Page 403).

ERZ-Staff-59

Reference(s): E3/T1/S1/A50, p.133-134

Table 32 - Asset Health Index Summary

Asset Category		Population	Average Health Index	Health Index Distribution: Very Poor (< 25%)	Poor (25 - <50 %)	Fair (50 - <70 %)	Good (70 - <85 %)	Very Good (>= 85%)	Average Age
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.

Response:

a) For underground cables, the results were derived from the asset age demographics, asset situation (i.e. tree retardant, non-tree retardant, directly buried or laid in duct), the empirical survival rate based on cable age and asset situation and derating factor for HI based on cable failure history. After calculating the health index of the cable based on its probability of survival, which is 1 minus probability of failure, the health index is de-rated based on cable failure history within the last five years. All cables that experienced 1 fault within the last five years will be de-rated by 90%, 2 faults = 70%, 3 faults=50% and >3 faults=25%.

b) For wood poles, the results were derived from the condition parameters of, pole strength, physical condition, pole accessories and service record which includes the pole age. Weighting given to pole strength is highest among all the condition parameters i.e. 38% for pole strength, 31% for physical condition, 23% for service record and 8% for pole accessories. The sub-condition parameter of service record is age which is based on probability of survival, which is 1 minus probability of failure. The health index calculation is finalized with the inclusion of a de-rating factor which is based on the minimum of overall pole condition assessment.

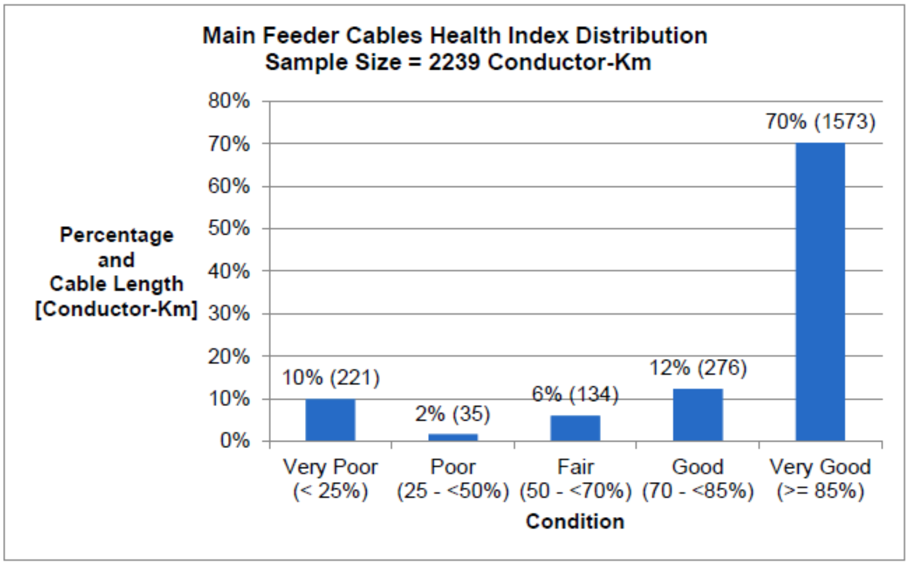
c) There are 12 transformers which are kept as spares; one in very poor condition; 7 in very good condition; and 4 in good condition. The health index calculation for spare transformers is based solely on age. The age of the unit that is in very poor condition was 59 years. Although 59 years is close to the expected end of life of a transformer in service, the spare unit was not subjected to the stresses and degradations that operating transformer experience, hence, may still be maintained as spare.

d) This trend is due to the fact that when asset reaches its typical useful life (i.e. when asset crosses the 20% probability of failure), there is a sharp decline in the survival rate of the asset. Because of this steep decline, comparatively few assets fall in the category of poor condition.

ERZ-Staff-60

Reference(s): 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.**

Response:

a) Age as well as whether the cable is direct buried or in duct are the only criteria used as condition parameters for health indexing the feeder cables. Cables aged more than 34 years fall in the category of very poor condition. Cables aged 31 to 33 fall in the category of poor condition and any poor condition cable which experienced any fault in the past is de-rated to very poor condition. The Health Index distribution is also based on the demographic profile of feeder cables. 29.7km out of 2239km cables are aged 31 to 33 which represent only 1.3% of total feeder cables and 219.5km out of 2239km cables are aged 34 and higher representing 9.8% of total feeder cables. Some of these cables aged 31 to 33 fell in very poor condition because of their failure history which de-rated their health index. Similarly some relatively younger cables fell in poor category because of their failure history.

b) Figure 62 cannot be plotted based solely on performance. The cable age as well as whether the cable is direct buried or in duct are the only criteria used for cable health indexing and a derating factor is introduced to modify the overall cable health index based on the past history of failures of cable.

ERZ-Staff-61

Reference(s): 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?

Response:

a) The presence of PCBs in mineral oil does not impact the asset's performance. PCB presence was incorporated as a de-rating factor to prioritize PCB transformers for replacement, based on the PCB content.

b) PCB content was not a condition parameter used in the determination of asset Health Index. It was used as a de-rating factor based on the PCB content after the Health Index had been calculated.

ERZ-Staff-62

Reference(s): 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.

Response:

The Table 42 contains information on the non-coincident daily peaks that occurred in 2011 and 2016.

It is not possible to classify feeder loading and associated condition that lead to the number of feeders to be over the 350/450 A. However Alectra Utilities' Enersource RZ monitors feeder loading and proposes measures to bring the loading within the planning and contingency guidelines.
The general reasons could have also been load transfers for substation work or overhead work or Emergency load transfers due to power outages.

ERZ-Staff-63

Reference(s): 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.

Response:

The use of the term 'improved lifecycle' of switchgear refers to:

- Longer lifespan based on material construction of solid dielectric switches over air-insulated switches.
- Reduced operating cost on dry ice cleaning as these units are self contained.

ERZ-Staff-64

Reference(s): 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?**

Response:

a) The samples were taken from transformers that were decommissioned.

b) Alectra Utilities' is not proposing to replace transformer solely upon asset age. The parameters used for Power Transformers Health Index calculations include: Visual inspection record, yearly oil/gas analysis, Doble testing, ratio/megger tests, age, historical events and loading.

c) Transformer replacement is not based solely upon the age of the transformer. Please refer to part b) of the response.

a) Alectra Utilities' does not have a policy but rather a practice which incorporates utilization as one of many components in determining the Health Index for the power transformer asset class. Please refer to response to ERZ-SEC-16 for the 2016 Kinectrics Asset Condition Assessment report, page 34 for explanation of the Health Index methodology.

ERZ-Staff-65

Reference(s): 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.

Response:

a) Synergies as defined here include the efficiency gains that may be achieved by replacing all components within the station which are at or near end of life and by coordinating with other drivers so as to develop integrated investments or projects and/or reduce impact to customers due to fewer outages.

Older stations typically contain a number of components that may reach end of life at about the same time.

The potential benefits of bundling include the following:

- Lower costs due to increase efficiency (e.g. lower mobilization/demobilization costs)
- Fewer outages, hence less outage coordination and reduced impact to customers and improved customer satisfaction.
- Minimized need to revisit a station
- Reduced overall travel time for field staff
- Improved overall reliability
- Reduced cost in Isolating and Energizing a station

- Reduced testing and commissioning cost

b) Alectra Utilities' has not developed a distinct business case recommending that all station work is bundled however, on a case by case basis, depending on the asset and other factors, bundling of the work is suggested at stations.

ERZ-Staff-66

Reference(s): 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?

Response:

a) Over 80% of equipment failures in 2016 were cable faults.

b) In 2013 the impact of cable failures on customer minutes of interruption was consistent with previous years. From 2014 to 2016 cable failures were increasing from 1.6MM customer minutes of interruption to almost 5MM customer minutes of interruption (Table 73 of DSP pg 363). The data over the 2014 to 2016 three year period indicates a rise in the number of cable failures and their impact on customer outage minutes in the Enersource RZ..

c) The health index calculation does include a de-rating factor based on cable failure trends, therefore the health index would justify cable replacement for areas with high rates of failure. This aligns with the justification for projects involving cable replacement.

d) In the Kinectrics Health Index, an additional de-rating factor based on cable failure trends was included, which would worsen the condition of cables, where this de-rating factor was applied.

e) Yes, based on the cable failure report that included 124 cable faults, 95.2% of cable failures were unjacketed, direct buried cables. Furthermore, 62.1% of these cables were solid core construction, which cannot be injected.

ERZ-Staff-67

Reference(s): 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?

Response:

a) No, poles are not replaced solely on age. Please see Alectra Utilities' response to ERZ-Staff 41 (c) for a listing of factors that would trigger proactive replacement based on inspection. Furthermore, failure of resistograph testing will trigger a replacement of the pole.

b) No, poles are not an asset that are 'run to failure' due to the risk and impact of a pole failure to public safety. Failure of a single pole could cascade and bring down multiple poles increase outage length. Poles could also fall on public and private property, posing an employee and public safety risk.

c) The consequence of a pole failure is similar for all poles. Poles with additional equipment such as transformers or switches will have an increased risk during evaluation due to criticality.

ERZ-Staff-68

Reference(s): E3/T1/S1/A50, p.249-257

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

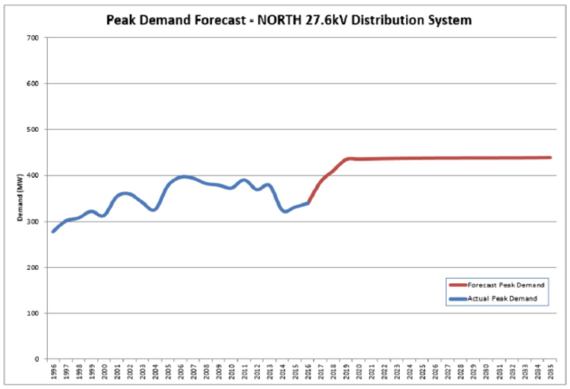


Figure 95 - Enersource RZ Peak Demand Forecast - South 27.6kV Distribution System – Extreme Weather Scenario (1996-2035)

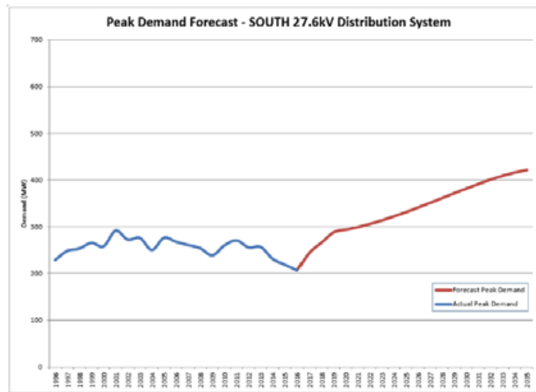


Figure 97 - Enersource RZ Peak Demand Forecast - West 44kV Distribution System – Extreme Temperature Scenario

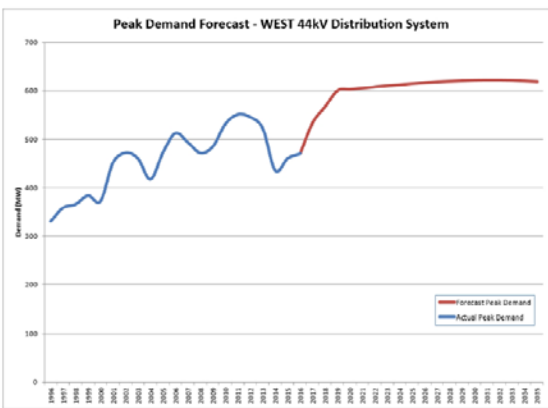
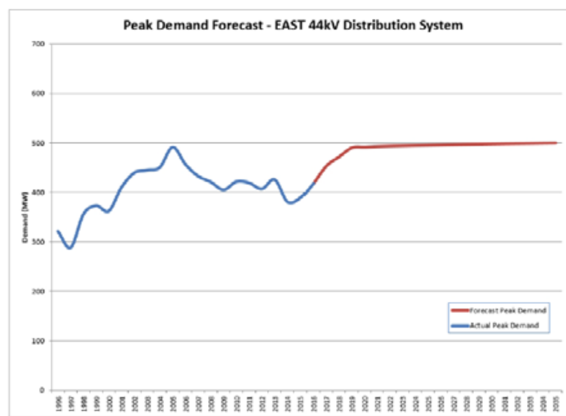


Figure 101 - Enersource RZ Peak Demand Forecast - East 44kV Distribution System – Extreme Weather Scenario (1996-2035)



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?

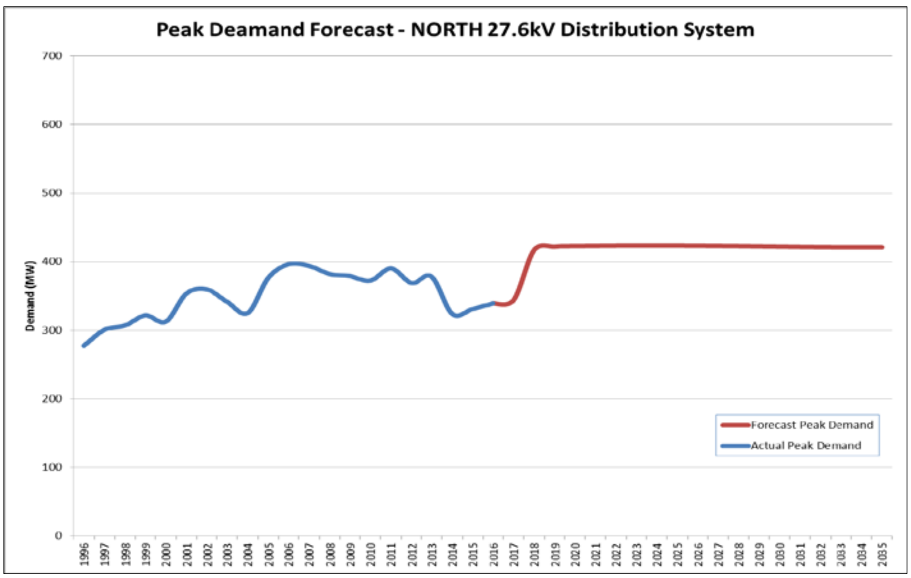
Response:

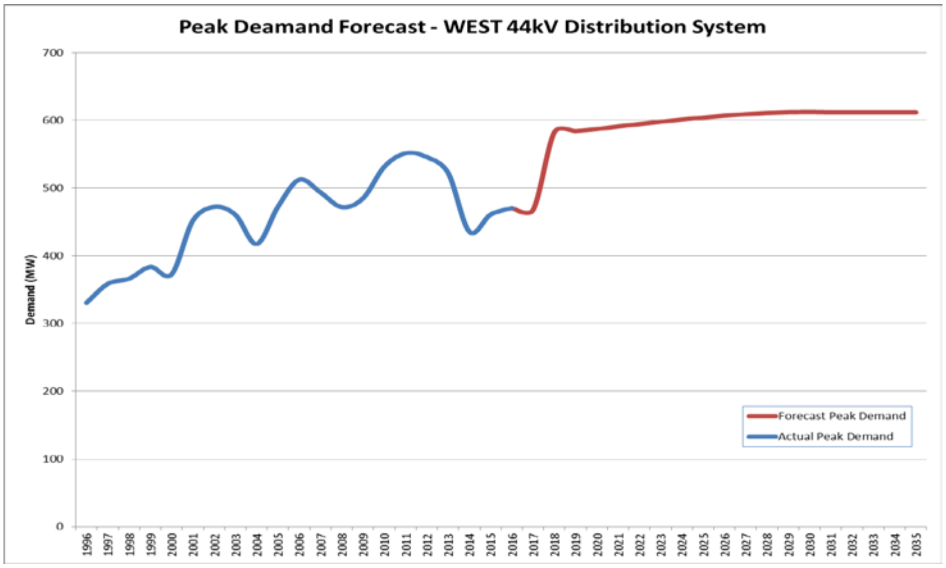
a) The forecasted and actual system peak for Year to date September 25th 2017 is provided in Table 1:

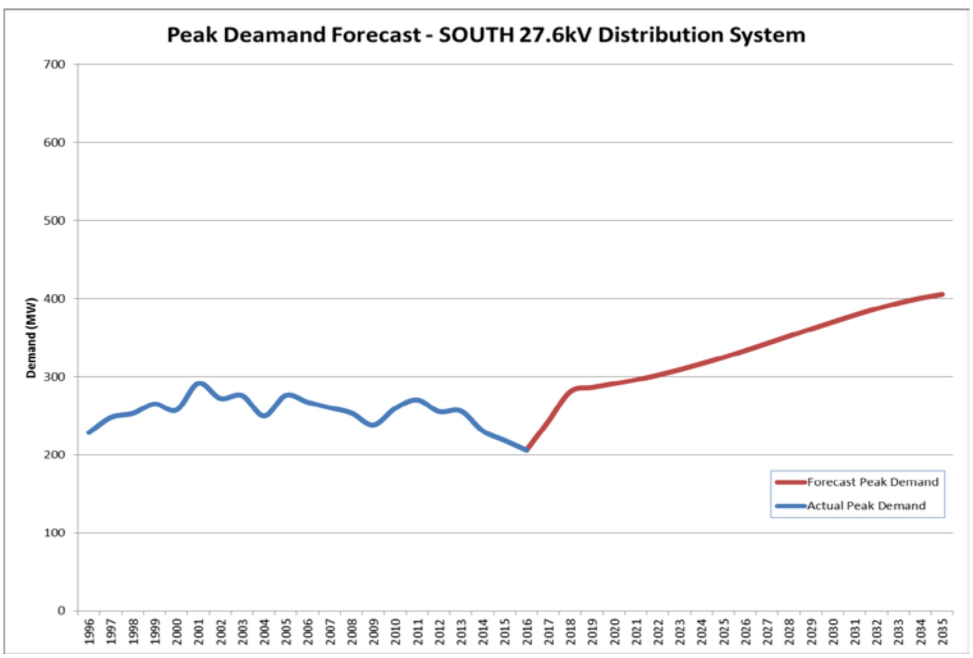
Table 1 – Actual and forecasted system peak

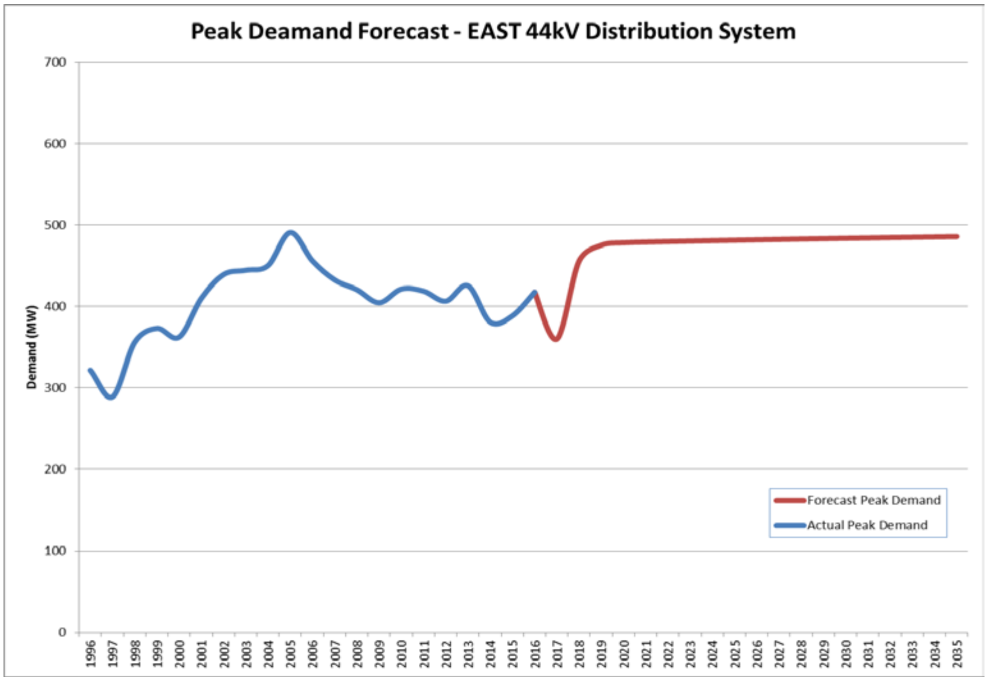
	2017 Peak Demand Forecast YTD Sept 25 2017 (MW)	2017 Actual Demand Forecast YTD Sept 25 2017 (MW)
NORTH	386	374
SOUTH	244	167
WEST	534	428
EAST	453	422

Please see the updated figures with the latest summer peak information




Peak Deamand Forecast - WEST 44kV Distribution System
Demand (MW)
0
100
200
300
400
500
600
700
1996 1997 1998 1999 2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035
Forecast Peak Demand
Actual Peak Demand


Peak Deamand Forecast - SOUTH 27.6kV Distribution System
Demand (MW)
0
100
200
300
400
500
600
700
1996 1997 1998 1999 2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035
Forecast Peak Demand
Actual Peak Demand



b) The existing 44KV infrastructure in the East system planning zone, namely the subtransmission feeders connected to Hydro One transmission stations, have sufficient capacity to accommodate the system peak over the forecast period.

ERZ-Staff-69

Reference(s): 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.

Response:

a) The basis of the anticipated future growth is the increase in customer connection request from the expected revitalization of the area. Details on the growth in the area is provided below.

Existing developments include:

The existing post office on the south-west corner of Stavebank and Lakeshore is being rebuilt and service moved from a single phase 54kW to a 3 phase 750kVA service.

Waterside Inn was upgraded in 2016 from 4.16kV-500kVA to 27.6kV-750kVA and other existing 300kVA service increased to 500kVA.

Townhomes at St. Lawrence have previously been converted to the 27.6kV voltage and the loop extended into the developing area.

Future developments:

The now closed No Frills grocery store lands at 99 Lakeshore are converting into a 10 storey condominium and 4 storey commercial building.

Stavebank road at Lakeshore is being realigned to address congestion and provide for future growth.

Inspiration Port Credit Development is proposing nine 3-10 storey buildings totalling 1200-1500 units.

Further intensification is expected as the above developments occur, including the apartment at 30 Port street. The old Texaco Petro Lands development is also occurring to the west and has a very conservative projection of 3000 units. (Mississauga Masterplan D10-149-003). Further, proposed 3 storey townhomes on the lakefront may become condos based on changes seen in other areas.

This list is not exhaustive, but addresses some of the larger developments in the area.

b) Alectra Utilities' confidence on the major revitalization in the area is very high. Several meetings have been held with contractors and consultants. The Inspiration Port Credit master plan was approved June 8, 2016, and latest plan amendment occurred on August 2, 2017.

Other projects such as the No Frills redevelopment have been made public by City of Mississauga's planning department in June 2012. The Texaco Petro Lands development plans were also provided in 2016.

ERZ-Staff-70

Reference(s): 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?

Response:

a) Enersource Hydro Mississauga became aware of this project prior to 2015, however the initial design details were provided to by Metrolinx in the fall/winter of 2015. A preliminary review of the project was started shortly after. Additionally, the necessary agreements were established in November 2016 and the preparation of draft designs was initiated afterwards.

b) Yes, Alectra Utilities' requires certain conditions prior to work being carried out. The design deposits were provided to Alectra to ensure costs associated with engineering and design are addressed. Similarly, any preparatory work for LRT relocations will be carried out after appropriate deposits are provided to Alectra Utilities' prior to start of construction.

ERZ-Staff-71

Reference(s): 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?

Response:

a) System renewal involves the identification and replacement of assets that are near or at the end of their useful lives based on inspection and condition assessments. The function of this is to maintain in service asset performance at acceptable levels while managing risk, to maintain system reliability levels and to manage asset replacement programs in a paced manner. Alectra Utilities' is focused on learning from past events in order to improve practices and the customer experience moving forward. For example, failure rates experienced in air insulated switchgear have resulted in a change of practice such that expansion projects requiring switchgear now utilize new solid di-electric units not prone to tracking. Another example involves porcelain insulators, which have been replaced with polymer insulators on all overhead expansion projects. This change was based on Alectra

Utilities' experience with the performance of porcelain insulators and wood pole fires. Similar approaches have been followed with respect to regulatory requirements to comply with federal regulations. This relates to the transformer backlog replacement project.

b) Asset condition assessments (ACA) have been completed annually since 2011. The ACA has not resulted in Alectra Utilities evaluating its assets to be in better or worse condition than was thought prior to the ACA evaluation.

c) Alectra Utilities' has not changed the useful life of its assets in the Enersource RZ.

ERZ-Staff-72

Reference(s): 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?

Response:

a) The pacing and deferral of system service expansion projects, which include Webb MS, Mini-Britannia MS and Duke MS construction, were made in order to incorporate the identified customer priorities and preferences attained from the customer engagement process. To address customer priorities, Alectra Utilities' will focus on Conservation Demand Management (CDM), particularly in the service areas to be supplied by the proposed new municipal stations.

The start of expansion investments related to the Light Rapid Transit has been deferred by a six month period in 2018 based on the readiness of Metrolinx to begin construction of the Hurontario Light Trail Transit project.

b) CDM programs are voluntary and not presently designed to be promoted to specific areas of a service area. The present CDM programs are designed to meet energy saving targets and not peak demand targets. It is possible that with low program uptake by customers,, Alectra Utilities may require to run the distribution system above the system planning criteria during peak demand times, thereby introducing risks of outages. By deferring the construction of new municipal stations, Alectra Utilities' will focus and invest in CDM programs specific to these areas, in order to pace peak demand growth in its service area, to accommodate a deferred construction date of the municipal stations.

c) Yes, throughout the engagement, Enersource RZ customers were asked to comment on their preferences in relation to the various investment categories (System Access, System Service, System Renewal and General Plant). By identifying customer preferences in relation to these investment categories, it was concluded that Enersource RZ customers expect Alectra Utilities' to uphold a robust capital investment program that ensures current reliability levels are maintained.

That said, Alectra Utilities' is mindful that most customers have identified electricity rates as a key priority. By identifying key customer priorities (lower rates) and preferences (investments to maintain reliability), the Alectra Utilities' is pacing or deferring certain system expansion projects in the Enersource DSP. Additionally, in the Enersource RZ Telephone Survey, fewer customers in all three rate classes supported System Service investments versus the other investment categories (Customer Engagement Report, Page 18).

ERZ-Staff-73

Reference(s): E3/T1/S1/A50, p.363-364

Figure 110 - Trend of Cable Failures in Number of Failures

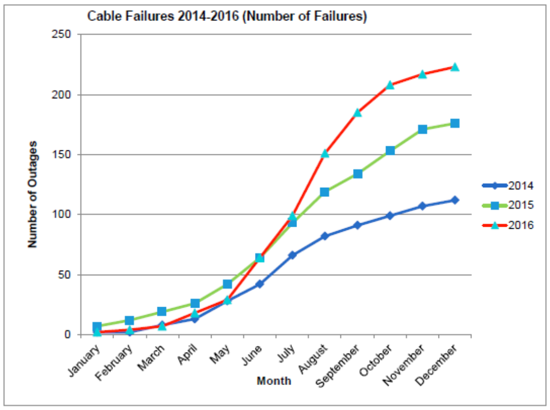
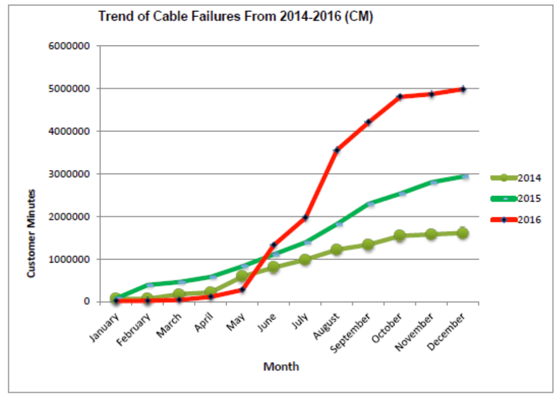


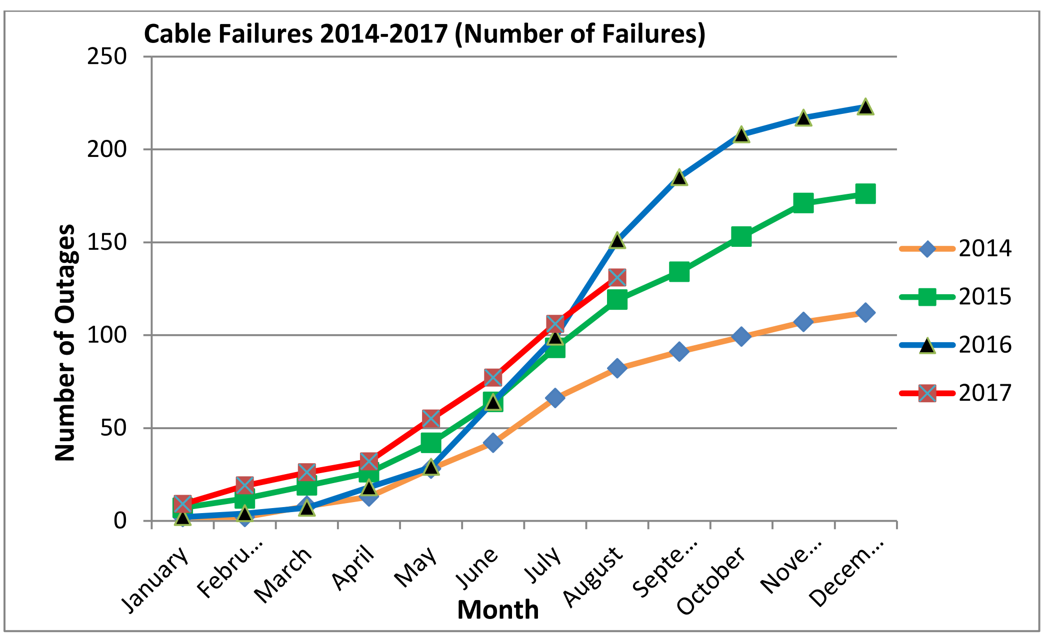
Figure 111 - Trend of Cable Failures in Customer Minutes

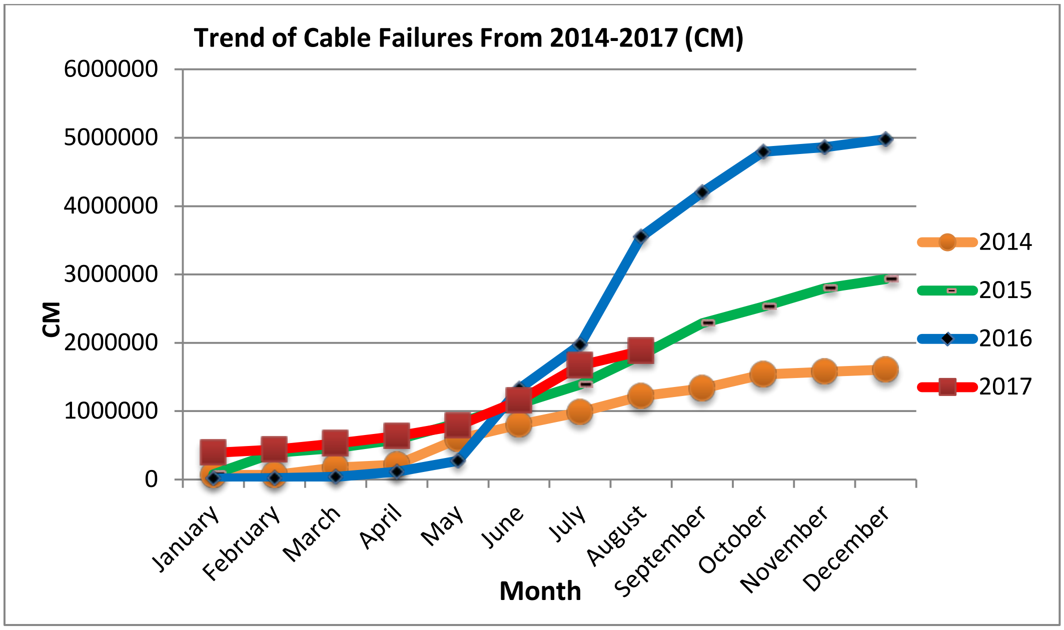


Please provide updated Figures 110 and 111 showing how 2017 cable failures are trending to date.

Response:

Figures 110 and 111 have been updated with data up to August 2017.



1 
Trend of Cable Failures From 2014-2017 (CM)
6000000
5000000
4000000
3000000
2000000
1000000
0
CM
January
February
March
April
May
June
July
August
September
October
November
December
Month
2014
2015
2016
2017

ERZ-Staff-74

Reference(s): 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.

Response:

a) Using the overlay methodology (referenced in the question E3/T1/S1/A50, p364) other assets in need of replacement, or other needs are bundled to generate synergies i.e. one truck role. Transformer characteristics are used to further prioritize a subdivision cable rebuild. For example, if two subdivisions had a similar number of cable faults, and one had 3 leaking transformers and the other none, the subdivision with the leaking transformers would be prioritized higher than that subdivision with no leaking transformers.

b) Based on the 6 ICM Subdivision rebuild projects, the estimated remaining useful life of the cable assets at the time they will be replaced are as follows:

- Folkway & Erin Mills – No useful life remaining
- Tenth Line – 3 sections of cable will have 4 years of useful life remaining but are financially fully depreciated.
- City Centre Drive – No useful life remaining
- Credit Woodlands – No useful life remaining
- Glen Erin and Montevideo – 3 cable segments will have 1 year of useful life but are financially fully depreciated.

- Glen Erin and Battleford – 1 cable segment with 1 year of useful life but is fully depreciated, 4 segments with 3 years of useful life but are fully depreciated, and 5 segments with 13 years of useful life remaining and they are not fully depreciated (2 years remaining).

ERZ-Staff-75

Reference(s): 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?).

Response:

a) Proactive switchgear replacements would be completed if the following conditions are apparent:
- Flashover/failure of a position (loss of operation or loss of equipment)
- Tracking and pitting along the fibreboards or switches (safety of staff, may lead to failure)
- Rusting on internal components related to switch operation which cannot easily be replaced (safety of staff, may lead to failure)
- Major rusting of the enclosure which has caused holes to appear that afford access to the public (safety of public)

b) Please see Alectra Utilities response to part a).

ERZ-Staff-76

Reference(s): 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**

Reference(s): _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?

Response:

a) The adoption of cold shrink splices occurred during 2000-2002.

b) Table 72 refers to cable failures, not heat shrink splice failures. Heat shrink splice related failures for the 2014 -2016 period are provided in Table 1.

Table - Heat shrink splice failures 2014-2016

Year	Heat Shrink Failures
2014	11
2015	3
2016	0

HRZ-Staff-1

Reference(s): 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.**

Response:

Alectra Utilities' is not requesting recovery of the remaining balance of stranded meter assets. The requested recovery on page 3 item e, should be excluded from the list of relief sought. Alectra Utilities' confirms that the 2018 Proposed Tariff of Rates and Charges for the Horizon Utilities RZ do not include a proposed rate rider for recovery of stranded meter assets.

HRZ-Staff-2

Reference(s): 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.**

Response:

a) Alectra Utilities’ provides the Cost of Power 2018 Annual Filing calculation as HRZ-Staff-2_Attach 1_2018 Annual Filing COP calculation
b) The Cost of Power calculation provided in Table 22, incorporates the reduction to the Rural Rate Protection charge of $0.0003/kWh and the new RPP rates effective July 1, 2017.
c) The number of customer used in the calculation of the Smart Meter Entity charge is the 2016 actual customer count for the residential and GS<50 kW classes, as filed in Horizon Utilities 2016 Annual Reporting and Record Keeping Requirements (“RRR”) 2.1.2 Filing.

HRZ-Staff-3

Reference(s): 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.

Response:

(a) The approved 2016 asset continuity schedule and the actual 2016 asset continuity schedule is provided as HRZ-Staff-3_Attach 1_2016 actual and approved continuity schedules.

(b) Table 1 below provides a list of capital projects completed in 2016 compared to a list of planned capital projects.

Table 1 – Comparison of Actual to Planned Capital Projects

Project ID	Project Name	2016 Approved Budget	2016 Actual Results
System Access			
SA-1	Customer Connections	$ 3,599,103	$ 9,239,493
SA-2	Road Relocations	$ 2,339,675	$ 3,015,979
SA-3	Meters	$ 2,101,174	$ 2,080,926
System Access Total		**$ 8,039,952**	**$ 14,336,398**

System Renewal			
4kV & 8kV Renewal			
SR-1	Central S/S	$ 1,556,000	$ 1,810,670
	Grantham S/S	$ 2,633,000	$ 2,920,716
	Strouds S/S	$ 1,533,000	$ 1,833,373
	Vine S/S	$ 2,472,000	$ 2,034,524
	Whitney S/S	$ 1,966,000	$ 709,291
	4kV & 8kV Renewal Subtotal	**$ 10,160,000**	**$ 9,308,573**
U/G (XLPE) Renewal			
SR-2	Ancaster/Flamborough/Dundas	$ 1,269,000	$ 1,728,048
	Hamilton Mountain	$ 1,996,000	$ 1,416,466
	St. Catharines	$ 1,661,000	$ 889,140
	U/G (XLPE) Renewal Subtotal	**$ 4,926,000**	**$ 4,033,654**
SR-3	**Reactive Renewal**	**$ 4,339,000**	**$ 5,101,302**
SR-4	**Substation Infrastructure Renewal**	**$ 473,000**	**$ 194,989**
Other Renewal			
SR-5	Pole Residual Replacements	$ 694,000	$ 1,400,333
SR-6	LDBS Renewal	$ 334,000	$ 273,982
SR-7	Proactive TX Replacements	$ 361,000	$ 341,876
SR-8	Gage TS Egress Feeder Renewal	$ 4,793,000	$ -
SR-9	Rear Lot Conversion	$ 542,000	$ 1,698,557
SR-OT	Other System Renewal	$ 303,649	$ 459,719
	Other Renewal Subtotal	**$ 7,027,649**	**$ 4,174,467**
System Renewal Total		**$ 26,925,649**	**$ 22,812,987**

System Service			
SS-2	Distribution Automation	$ -	$ 327,483
SS-3	Waterdown 3rd Feeder	$ -	$ 1,166,471
SS-9	Mohawk/Nebo T/S Upgrade	$ -	$ 373,146
SS-OT	Other System Service*	$ 294,732	-$ 398,291
System Service Total		**$ 294,732**	**$ 1,468,809**

General Plant			
Information Systems Technology ("IST")			
GP-1	Annual Corporate Computer Replacement	$ 324,000	$ 383,000
GP-5	Capital Lease - IBM	$ 900,000	$ -
	IST Sub-Total	**$ 1,224,000**	**$ 383,000**
Buildings			
GP-6	Building Renovations - John and Hughson Street	$ 1,600,000	$ 2,048,000
GP-7	Building Renovations - Stoney Creek	$ -	$ 102,000
GP-8	Building Security Replacement	$ 200,000	$ 74,000
GP-9	John Street Roof Replacement	$ -	$ 210,000
GP-11	John Street Window Replacement	$ 300,000	$ -
	Buildings Sub-Total	**$ 2,100,000**	**$ 2,434,000**
GP-12	**Vehicle Replacement**	**$ 780,000**	**$ 614,882**
GP-13	**Tools, Shop and Garage Equipment**	**$ 567,600**	**$ 297,719**
GP-OT	**Other General Plant**	**$ 1,215,600**	**$ 1,947,471**
General Plant Total		**$ 5,887,200**	**$ 5,677,072**
Total		**$ 41,147,533**	**$ 44,295,265**

* Note: System Service includes the Hydro One CCRA payment reduction adjustment for $504K

(c) Table 2 below provides a comparison of the approved capital expenditures to actual expenditures for each investment category.

Table 2 – Comparison of Approved to Actual Capital Expenditures

Investment Category	Approved Expenditures	Actual Expenditures	Actual vs. Budget
System Access	8,039,952	14,392,618	6,352,666
System Renewal	26,925,649	22,962,030	(3,963,619)
System Service*	294,732	663,692	368,960
General Plant	5,887,200	5,415,481	(471,719)
Total	**41,147,533**	**43,433,820**	**2,286,287**

* Note: System Service includes the Hydro One CCRA payment reduction adjustment for $504K

Electricity Distribution Operations

Fixed Asset Continuity Schedule

December 31, 2016

Company 11			Cost				Accumulated Depreciation						
Useful Life	Component	Component Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value	Proceeds on Disposal	Gain (Loss) on Disposal
NA	1805	Land - Substations	414,741.45	-	-	414,741.45	-	-	-	-	414,741.45	-	-
40	1808	Buildings - Substations	850,332.86	-	-	850,332.86	333,558.04	54,822.33	-	388,380.37	461,952.49	-	-
5	1810	Leasehold Improvements	0.01	-	-	0.01	0.01	-	-	0.01	-	-	-
40	1821	Substation Transformers	1,278,581.65	182,939.71	-	1,461,521.36	166,447.95	37,740.03	-	204,187.98	1,257,333.38	-	-
40	1822	Substation Switchgear and Other Elements	6,416,231.94	129,922.13	-	6,546,154.07	545,127.45	163,295.28	-	708,422.73	5,837,731.34	-	-
40	1823	Substation Breakers and Reclosures	4,956,726.30	114,085.09	-	5,070,811.39	372,124.85	128,448.20	-	500,573.05	4,570,238.34	-	-
50	1831	Poles, Towers and Fixtures - Concrete	22,778,992.87	5,492,922.00	(83,019.09)	28,188,895.78	1,881,563.71	521,979.85	(10,553.50)	2,392,990.06	25,795,905.72	-	(72,465.59)
40	1832	Poles, Towers and Fixtures - Wood	58,783,720.95	4,323,534.50	(435,533.17)	62,671,722.28	6,720,334.40	1,678,492.28	(69,912.03)	8,328,914.65	54,342,807.63	240,072.62	(125,548.52)
50	1836	Overhead Conductors and Devices Secondary and Service	24,651,267.00	2,657,510.28	(361,869.37)	26,946,907.91	2,116,456.56	552,869.01	(45,089.55)	2,624,236.02	24,322,671.89	-	(316,779.82)
40	1837	Overhead Conductors and Devices Switches	22,647,644.36	2,198,893.02	(184,574.46)	24,661,962.92	2,712,390.19	684,658.50	(31,783.69)	3,365,265.00	21,296,697.92	-	(152,790.77)
30	1838	Overhead Conductors and Devices Capacitor Banks	110,744.54	22,425.57	-	133,170.11	14,480.79	4,084.38	-	18,565.17	114,604.94	-	-
50	1839	Overhead Conductors and Devices Primary	14,057,212.89	1,564,199.64	(739,339.27)	14,882,073.26	1,380,247.50	324,245.49	(96,731.34)	1,607,761.65	13,274,311.61	-	(642,607.93)
40	1843	Underground Conduit Chanmbers and Other Elements	75,538,753.45	6,014,564.89	(31,301.83)	81,522,016.51	10,411,203.16	2,483,259.76	(5,079.59)	12,889,383.33	68,632,633.18	-	(26,222.24)
70	1844	Underground Conductors and Devices Primary PILC	34,682,109.31	3,438,906.54	(63,766.67)	38,057,249.18	2,711,500.26	603,238.25	(5,918.50)	3,308,820.01	34,748,429.17	-	(57,848.17)
40	1846	Underground Conductors and Devices Primary XLPE	24,065,833.70	4,511,716.11	(406,200.01)	28,171,349.80	3,391,675.76	805,220.06	(70,079.23)	4,126,816.59	24,044,533.21	-	(336,120.78)
40	1847	Underground Conductors and Devices Secondary and Service in	23,112,650.68	3,664,830.67	(15,710.02)	26,761,771.33	1,983,189.01	676,747.10	(2,870.93)	2,657,065.18	24,104,706.15	-	(12,839.09)
25	1848	Underground Conductors and Devices Secondary and Service Di	3,643,051.20	336,010.01	(35,643.60)	3,943,417.61	1,505,923.35	221,439.05	(10,210.57)	1,717,151.83	2,226,265.78	-	(25,433.03)
25	1849	Underground Conductors and Devices Switches and Switchgear	10,752,004.24	1,983,924.89	(122,075.33)	12,613,853.80	2,930,875.53	553,611.32	(37,555.71)	3,446,931.14	9,166,922.66	-	(84,519.62)
40	1851	Line Transformers Overhead	40,469,833.85	3,758,147.71	(763,182.51)	43,464,799.05	5,211,585.74	1,253,680.02	(115,005.78)	6,350,259.98	37,114,539.07	277,087.62	(371,089.11)
30	1852	Line Transformers Underground	34,720,260.71	3,707,467.73	(232,208.22)	38,195,520.22	6,234,717.64	1,471,597.31	(53,493.83)	7,652,821.12	30,542,699.10	-	(178,714.39)
50	1856	Services	20,627,714.61	1,399,045.00	-	22,026,759.61	2,089,689.22	470,479.50	-	2,560,168.72	19,466,590.89	-	-
25	1860	Meters - Wholesale and Interval	17,713,130.86	501,817.59	-	18,214,948.45	2,978,342.73	796,252.07	-	3,774,594.80	14,440,353.65	-	-
15	1862	Meters - Smart Meters Residential	20,065,729.92	31,665.99	(310,000.20)	19,787,395.71	7,769,965.51	1,595,665.42	(147,014.97)	9,218,615.96	10,568,779.75	-	(162,985.23)
15	1863	Meters - Smart Meters Commercial	6,538,513.85	358,478.99	(89,558.34)	6,807,434.50	1,418,591.96	447,506.55	(42,429.34)	1,823,669.17	4,983,765.33	-	(47,129.00)
25	1865	Meters - CT and PT	-	1,188,963.88	-	1,188,963.88	-	11,761.30	-	11,761.30	1,177,202.58	-	-
25	1869	Meters - Stranded Meters	7,291,816.65	-	-	7,291,816.65	2,430,605.76	2,430,605.76	-	4,861,211.52	2,430,605.13	-	-
NA	1905	Land	1,067,629.41	-	-	1,067,629.41	-	-	-	-	1,067,629.41	-	-
50	1906	Land Rights	90,487.12	-	-	90,487.12	16,684.20	3,336.84	-	20,021.04	70,466.08	-	-
30	1908	Buildings and Fixtures	28,692,804.44	3,333,584.96	-	32,026,389.40	5,474,754.31	1,177,642.63	-	6,652,396.94	25,373,992.46	-	-
5	1910	Leasehold Improvements	-	-	-	-	-	-	-	-	-	-	-
10	1915	Office Furniture and Equipment	4,136,931.31	31,900.95	-	4,168,832.26	1,529,401.86	436,757.29	-	1,966,159.15	2,202,673.11	-	-
3	1920	Computer Equipment - Hardware 3 years	3,928,948.22	554,172.53	-	4,483,120.75	2,419,789.31	803,710.98	-	3,223,500.29	1,259,620.46	-	-
5	1921	Computer Equipment - Pre March 2004	9,520.91	-	-	9,520.91	9,520.91	-	-	9,520.91	-	-	-
5	1922	Computer Equipment - Hardware 5 years	4,540,128.72	99,224.00	-	4,639,352.72	3,243,786.50	610,662.06	-	3,854,448.56	784,904.16	-	-
15	1930	Transportation Heavy and Trailers	6,848,654.83	276,368.82	(0.03)	7,125,023.62	3,649,992.08	514,962.77	(0.03)	4,164,954.82	2,960,068.80	29,809.20	29,809.20
8	1931	Transportation Light vehicles	2,349,823.02	309,977.00	(0.04)	2,659,799.98	1,825,616.47	211,419.02	(0.04)	2,037,035.45	622,764.53	3,862.80	3,862.80
5	1932	Transportation Passenger vehicles	264,417.66	28,536.00	(0.01)	292,953.65	161,912.25	38,147.56	(0.01)	200,059.80	92,893.85	-	-
10	1935	Stores Equipment	421,165.68	166,178.00	-	587,343.68	260,881.47	51,366.32	-	312,247.79	275,095.89	-	-
10	1940	Tools, Shop and Garage Equipment	4,236,039.54	297,718.85	-	4,533,758.39	1,830,265.01	427,214.35	-	2,257,479.36	2,276,279.03	-	-
10	1945	Measurement and Testing Equipment	1,133,254.02	219,310.70	-	1,352,564.72	563,892.56	109,007.92	-	672,900.48	679,664.24	-	-
10	1950	Power Operated Equipment	35,360.08	-	-	35,360.08	35,360.08	-	-	35,360.08	-	-	-
10	1955	Communications Equipment	1,861,336.22	17,622.57	-	1,878,958.79	1,024,588.40	218,726.81	-	1,243,315.21	635,643.58	-	-
8	1970	Load Management Controls - Customer Premises	312,338.08	-	-	312,338.08	258,012.60	48,824.42	-	306,837.02	5,501.06	-	-
20	1975	Solar PV - Panels and Racking	-	-	-	-	-	-	-	-	-	-	-
20	1976	Solar PV - Invertors	-	-	-	-	-	-	-	-	-	-	-
15	1981	System Supervisory Protection and control	300,312.95	-	-	300,312.95	133,904.75	24,214.54	-	158,119.29	142,193.66	-	-
15	1982	System Supervisory Protection	689,392.89	-	-	689,392.89	337,171.21	51,894.08	-	389,065.29	300,327.60	-	-
8	1985	Sentinel Lighting Rental Units	-	-	-	-	-	-	-	-	-	-	-
	1995	Contributions and Grants	(34,882,612.16)	-	552,948.00	(34,329,664.16)	(8,104,787.11)	(1,607,579.88)	88,472.00	(9,623,894.99)	(24,705,769.17)	-	464,476.00
	1996	S/S Contribution	7,956,729.52	-	-	7,956,729.52	1,861,520.72	357,112.18	-	2,218,632.90	5,738,096.62	-	-
	2050	Completed Construction Not Classified - Electric	825,340.65	(825,340.65)	-	-	-	-	-	-	-	-	-
		Total tangible assets	510,985,602.96	52,091,225.67	(3,321,034.17)	559,755,794.46	83,842,864.66	21,449,118.71	(655,256.64)	104,636,726.73	455,119,067.73	550,832.24	(2,114,945.29)
		Intangible Assets											
	1609	Substation contributions	19,045,847.30	(504,000.00)	-	18,541,847.30	2,252,757.93	985,321.79	-	3,238,079.72	15,303,767.58	-	-
3	1611	Software - 3 years	5,709,761.57	276,948.84	-	5,986,710.41	4,230,089.21	797,124.47	-	5,027,213.68	959,496.73	-	-
5	1612	Software - 5 years	8,894,770.55	65,528.85	-	8,960,299.40	4,270,593.15	1,342,491.02	-	5,613,084.17	3,347,215.23	-	-
		Total Intangible Assets	33,650,379.42	(161,522.31)	-	33,488,857.11	10,753,440.29	3,124,937.28	-	13,878,377.57	19,610,479.54	-	-
		Leased Assets											
3	2005	Leased equipment	1,283,363.37	-	-	1,283,363.37	820,130.00	139,109.16	-	959,239.16	324,124.21	-	-
		Total Leased Assets	1,283,363.37	-	-	1,283,363.37	820,130.00	139,109.16	-	959,239.16	324,124.21	-	-
		Total Capital Additions	545,919,345.75	51,929,703.36	(3,321,034.17)	594,528,014.94	95,416,434.95	24,713,165.15	(655,256.64)	119,474,343.46	475,053,671.48	550,832.24	(2,114,945.29)
		Work in Process											
	2055	Work in process - distribution	6,140,224.15	(1,424,344.77)	-	4,715,879.38	-	-	-	-	4,715,879.38	-	-
	2055	Work in process - other	408,415.02	(261,591.48)	-	146,823.54	-	-	-	-	146,823.54	-	-
	2055	WIP transferred to Completed construction 2055	(825,340.65)	825,340.65	-	-	-	-	-	-	-	-	-
		Total Intangible Assets	5,723,298.52	(860,595.60)	-	4,862,702.92	-	-	-	-	4,862,702.92	-	-
		Total Fixed, Intangible and Leased Assets	551,642,644.27	51,069,107.76	(3,321,034.17)	599,390,717.86	95,416,434.95	24,713,165.15	(655,256.64)	119,474,343.46	479,916,374.40	550,832.24	(2,114,945.29)
		Capital contributions - Distribution	(31,800,938.80)	(7,426,568.45)	-	(39,227,507.25)	(2,062,696.30)	(933,365.86)	-	(2,996,062.16)	(36,231,445.09)	-	-
		Capital Contributions - Fit	-	(207,870.41)	-	(207,870.41)	-	-	-	-	(207,870.41)	-	-
		Capital contributions - Total	(31,800,938.80)	(7,634,438.86)	-	(39,435,377.66)	(2,062,696.30)	(933,365.86)	-	(2,996,062.16)	(36,439,315.50)	-	-

Appendix 2-BA2
Fixed Asset Continuity Schedule - Approved

Year **2016**

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
43.1	1675	Standby Generators	0	0	0	0	0	0	0	0	0
47	1609	Capital Contributions	12,419,847	0	0	12,419,847	-2,370,303	-818,588	0	-3,188,891	9,230,957
N/A	1805	Land - Substations	414,741	0	0	414,741	0	0	0	0	414,741
1	1808	Buildings - Substations	879,005	0	0	879,005	-372,728	-55,897	0	-428,625	450,381
13	1810	Leasehold Improvements	0	0	0	0	-0	0	0	-0	0
47	1820	Substation transformers	13,526,403	902,070	0	14,428,473	-1,082,264	-344,767	0	-1,427,032	13,001,442
47	1830	Poles, towers and fixtures - concrete	83,011,520	8,995,690	-463,325	91,543,885	-8,762,710	-2,307,642	37,537	-11,032,815	80,511,070
47	1835	Overhead conductors and devices - secondary service	61,446,615	5,206,255	-915,942	65,736,928	-6,361,865	-1,595,451	63,459	-7,893,857	57,843,071
47	1840	Underground conduit chambers and other elements	75,336,655	5,146,835	-68,980	80,414,511	-10,397,269	-2,456,831	5,541	-12,848,559	67,565,952
47	1845	Underground conductors and devises primary PILC	85,783,560	5,121,047	-781,865	90,122,742	-12,278,077	-2,557,013	69,740	-14,765,351	75,357,391
47	1850	Line transformers - Overhead	79,830,690	8,537,311	-659,995	87,708,005	-11,817,685	-2,966,019	64,410	-14,719,294	72,988,711
47	1855	Services	23,695,272	3,904,951	0	27,600,224	-2,204,204	-574,137	0	-2,778,342	24,821,882
47	1860	Meters	44,713,517	2,101,174	-114,831	46,699,860	-12,434,488	-2,794,014	24,940	-15,203,562	31,496,297
N/A	1905	Land	1,067,629	0	0	1,067,629	0	0	0	0	1,067,629
CEC	1906	Land Rights	90,487	0	0	90,487	-16,684	-3,337	0	-20,021	70,466
1	1908	Buildings & Fixtures	27,483,949	1,995,000	0	29,478,949	-5,873,133	-1,154,568	0	-7,027,701	22,451,248
13	1910	Leasehold Improvements	0	0	0	0	0	0	0	0	0
8	1915	Office Furniture & Equipment	3,756,896	69,000	0	3,825,896	-1,603,373	-442,132	0	-2,045,505	1,780,391
52	1920	Computer - Hardware	8,994,274	825,500	0	9,819,774	-5,605,527	-1,595,149	0	-7,200,676	2,619,098
12	1611	Computer - Software	16,008,579	455,500	0	16,464,079	-9,797,234	-3,157,219	0	-12,954,453	3,509,626
10	1930	Transportation Equipment	9,672,000	780,000	0	10,452,000	-6,315,539	-1,106,815	0	-7,422,353	3,029,647
8	1935	Stores Equipment	417,864	0	0	417,864	-260,331	-47,431	0	-307,762	110,102
8	1940	Tools, Shop & Garage Equipment	4,107,395	567,600	0	4,674,995	-1,859,061	-447,470	0	-2,306,530	2,368,465
8	1945	Measurement & Testing Equipment	1,283,648	89,600	0	1,373,248	-614,408	-141,131	0	-755,538	617,710
8	1950	Power operated Equipment	35,360	0	0	35,360	-35,354	0	0	-35,354	6
10	1955	Communications Equipment	1,997,055	5,000	0	2,002,055	-1,039,496	-230,472	0	-1,269,968	732,087
8	1970	Load Management controls	312,338	0	0	312,338	-258,038	-48,856	0	-306,894	5,444
8	1980	System Supervisory Protection and Control	1,682,817	200,000	0	1,882,817	-520,184	-126,853	0	-647,037	1,235,780
47	1996	Hydro One S/S Contribution	7,956,730	0	0	7,956,730	-1,862,612	-357,384	0	-2,219,996	5,736,733
47	1995	Contributions & Grants	-34,882,612	0	0	-34,882,612	8,104,787	1,607,580	0	9,712,367	-25,170,245
10	2005	Capital Lease	820,130	900,000	-820,130	900,000	-820,130	-300,000	820,130	-300,000	600,000
		Sub-Total	**531,862,367**	**45,802,533**	**-3,825,068**	**573,839,833**	**-96,457,911**	**-24,021,596**	**1,085,758**	**-119,393,749**	**454,446,084**
		Less Socialized Renewable Energy Generation Investments (input as negative)				0				0	0
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				0				0	0
	2440	***Less Capital Contributions 2011 and future years***	29,688,078	4,655,000	0	34,343,078	-2,037,379	-884,000	0	-2,921,379	31,421,700
		Total PP&E	**502,174,289**	**41,147,533**	**-3,825,068**	**539,496,754**	**-94,420,532**	**-23,137,596**	**1,085,758**	**-116,472,370**	**423,024,384**
		Work in Process	3,164,006	0		3,164,006	0	0	0	0	3,164,006
		Total PP&E Including WIP	**505,338,295**	**41,147,533**	**-3,825,068**	**542,660,760**	**-94,420,532**	**-23,137,596**	**1,085,758**	**-116,472,370**	**426,188,390**

HRZ-Staff-4

Reference(s): Table 24 – Impact to Revenue Requirement due to Update of Cost of Capital Parameters – Horizon Utilities RZ

Reference(s): 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

Response:

a) Table 24 – Impact to Revenue Requirement due to Update of Cost of Capital Parameters Horizon Utilities RZ, was not updated to reflect the Cost of Power update presented in Table 22 – Cost of Power 2018 Annual Filing vs. Custom IR – Horizon Utilities RZ. Alectra Utilities has provided an update to Table 24 below. The rate base in the update to Table 24 below of $526,629,152 reconciles to the rate base presented in the revenue requirement work from model.

Table 24 - Impact to Revenue Requirement due to Update of Cost of Capital Parameters Horizon Utilities RZ (Updated)

Description	%	2018 Custom IR Application EB-2014-0002	%	2018 Annual Filing After COP Update	%	2018 Annual Filing After COP and COC Parameter Update	Increase/ (Decrease) in Revenue Requirement due to Cost of Power Update	Increase/ (Decrease) in Revenue Requirement due to Cost of Capital Parameters
Rate Base		$532,017,706		$526,629,152		$526,629,152	($5,388,554)	$0
Rate Base Breakdown								
Short Term Debt	4.00%	$21,280,708	4.00%	$21,065,166	4.00%	$21,065,166	($215,542)	$0
Long Term Debt	56.00%	$297,929,915	56.00%	$294,912,325	56.00%	$294,912,325	($3,017,590)	$0
Deemed Equity	40.00%	$212,807,082	40.00%	$210,651,661	40.00%	$210,651,661	($2,155,422)	$0
Revenue Requirement Components								
Deemed Interest - Short Term Debt	2.16%	$459,663	2.16%	$455,008	1.76%	$370,747	($4,656)	($84,261)
Deemed Interest - Long Term Debt	3.62%	$10,791,992	3.62%	$10,682,685	3.62%	$10,682,685	($109,307)	$0
Return on Equity	9.30%	$19,791,059	9.30%	$19,590,604	8.78%	$18,495,216	($200,454)	($1,095,389)
PILs Gross-Up	26.50%	$7,135,552	26.50%	$7,063,279	26.50%	$6,668,343	($72,273)	($394,936)
Total Revenue Requirement before OM&A and Deprn	**7.18%**	**$38,178,265**	**7.18%**	**$37,791,576**	**6.88%**	**$36,216,990**	**($386,689)**	**($1,574,585)**

HRZ-Staff-5

Reference(s): 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.

Response:

a) The opening balance in the '2016 actuals ESM' column excludes the Earning Sharing Mechanism ("ESM") amount as this column is used to calculate actual 2016 ROE. The 2016 actual ROE is compared to Horizon Utilities approved ROE to determine the ESM amount, as provided in Exhibit 2, Tab 1, Schedule 6, Table 28 – Summary of ESM Calculation - Horizon Utilities RZ, p.7.

b) The $33,508 difference is due an error in the amount included for interest in the ESM calculation at year end. This amount should have been excluded from the calculation at that time.

HRZ-Staff-6

Reference(s): 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.

Response:

a) On September 28, 2017, the Ontario Energy Board issued its Decision and Order on Hydro One Networks Inc. application for electricity transmission revenue requirement and related charges to the Uniform Transmission Rates beginning January 1, 2017 and January 1, 2018. The OEB ordered Hydro One Networks Inc. to file the draft revenue requirement/charge determinant order and the draft UTR rate order no later than October 10, 2017. The 2017 UTRs have not been finalized at the time of this filing.

HRZ-Staff-7

Reference(s): Attachment 6a - Bill Impact Tariff Sheet
Table 45 - Distribution Bill Impacts by Rate Class
Table 46 - Distribution Bill and Rate Rider Impacts by Rate Class
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

Response:

a) The difference in the bill impacts between Tables 45, 46 and 47 and Attachment 6a, is due to the rounding of the LRAMVA rate rider for the residential class. The ‘Round’ function was used in Attachment 6a for all rates. This should have been applied to the LRAMVA rate used to calculate the bill impacts presented in Tables 45, 45 and 47. The total bill impact for GS<50 class in Table 47 was presented as $1.22. This is a typo in the table and should have been presented as $1.12.

An update to Table 45, Table 46 and Table 45 is provided below. Alectra Utilities’ notes minor changes to Table 47 for all classes due to the rounding of the retail transmission service rates.

Table 45 - Distribution Bill Impacts by Rate Class (updated)

Distribution Bill Impacts				
Customer Class	Billing Units	Average Monthly Volume	2018 vs. 2017 $	2018 vs. 2017 %
Residential	kWh	750	$ (1.65)	(5.85)%
GS<50	kWh	2,000	$ (2.40)	(3.68)%
GS>50	kW	250	$ (2.80)	(0.27)%
Large User	kW	5,000	$ 898.45	2.92%
Large User with Dedicated Assets	kW	20,000	$ (64.42)	(0.53)%
Street Lighting	kW	4,974	$ (3,694.87)	(3.49)%

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

Table 46 - Distribution Bill and Rate Rider Impacts by Rate Class (updated)

Distribution Bill and All Rate Rider Bill Impacts				
Customer Class	Billing Units	Average Monthly Volume	2018 vs. 2017	
			$	%
Residential	kWh	750	$ (0.41)	(1.40)%
GS<50	kWh	2,000	$ 0.70	1.04%
GS>50	kW	250	$ (235.52)	(24.27)%
Large User	kW	5,000	$ 6,002.35	25.73%
Large User with Dedicated Assets	kW	20,000	$ 19,325.58	(133.82)%
Street Lighting	kW	4,974	$ (7,017.65)	(6.73)%

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

Table 47 – Total Bill Impacts by Rate Class (before HST) (updated)

Total Bill Impacts				
Customer Class	Billing Units	Average Monthly Volume	2018 vs. 2017	
			$	%
Residential	kWh	750	$ (0.26)	(0.25)%
GS<50	kWh	2,000	$ 1.12	0.40%
GS>50	kW	250	$ (210.70)	(1.36)%
Large User	kW	5,000	$ 6,570.85	1.87%
Large User with Dedicated Assets	kW	20,000	$ 21,599.58	1.67%
Street Lighting	kW	4,974	$ (6,630.21)	(1.96)%

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

HRZ-Staff-8

Reference(s): 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.**

Response:

Alectra Utilities' has updated the continuity schedule for the Horizon Utilities Rate Zone to include the correct LRAMVA balances. The update is identified in the table below under the "RRR Filing" column and is included in the IRM Model filed with Alectra Utilities' response to HRZ-Staff-18.

The reconciliation from the "RRR filing" to the "IRM LRAMVA claim" by year is shown in the table below. Also detailed in the table below is the "Updated IRM LRAMVA claim" which varies from the "IRM LRAMVA claim" as a result of the IESO's Final CDM verified report for 2016 and the timing of revenue recognition.

Attachment 6b- IRM Model Horizon Utilities RZ
Continuity Schedule- 1568

Ending Balance in Year	RRR filing ($)	IRM LRAMVA Claim ($)	Updated IRM LRAMVA Claim ($)
2011			
2012	- 237,493	- 237,493	
2013	- 240,980	- 240,980	293,429
2014	- 304,338	- 304,338	895,317
2015	25,006	25,006	1,330,593
2016	329,027	329,027	1,344,977

HRZ-Staff-9

Reference(s): 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).**

Response:

a) In the Horizon RZ LRAMVA model tab 3. Distribution Rates, historical rates have been manually adjusted by ($0.0001) to reflect a rate rider for Application of Tax Change not previously captured in the LRAMVA work form.

b) Alectra Utilities' withdraws the recovery of 2011 persistence amounts in the 2012 lost revenue. The Horizon LRAMVA model tab 4. 2011-2014 LRAM has been updated accordingly.

c) As per the response in part b) above the associated carrying charges arising from the 2011 persistence savings have been excluded from 2013-2015.

d) As explained above in response to part b) the 2012 amounts have been excluded.

HRZ-Staff-10

Reference(s): Tab 1 of LRAMVA Work Form
Tab 1-a of LRAMVA Work Form
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.

Response:

a) In 2015, the City of Hamilton commenced a multi-year project to replace existing high intensity discharge streetlights with LED streetlights. This followed a small pilot project involving the installation of 103 new LED streetlights in late 2014. The first phase of the multi-year project was completed from May to December 2015 and involved the installation of 10,319 new fixtures.

The new LED streetlights installed in both the pilot and the first phase of the multi-year project were eligible for incentives under the Save on Energy Equipment Replacement Incentive Initiative (now known as the Retrofit Program), funded by the Ontario Power Authority (now the IESO).

b) Horizon RZ received persistence information from the IESO related to this Street Lighting Project. The persistence information was included on Tab “5. 2015-2020 LRAM” on row 84”. Please see attached spreadsheet (Ref: IESO Streetlighting Project Verified Result) as backup According to the Chapter 3 Incentive Rate-Setting Applications of the OEB “Filing Requirements For Electricity Distribution Rate Applications – 2017 Edition for 2018 Rate Applications”, on Page 15, the requirements include “A statement confirming whether additional documentation or data was provided in support of projects that were not included in the LDC’s Final CDM Annual Report (i.e., street lighting projects). This data can be added to the work form in Tab 8 as applicable.” Therefore as per the requirements, Tab “8. Streetlighting” in the LRAMVA Work Form includes the demand savings that were not included in Horizon’s Final CDM Annual Report.

c) According to the IESO support on the Street Lighting Project (Ref: IESO Streetlighting Project Verified Result), Street Lighting savings were reported in both Gross and Net savings in kWh. The total gross saving reported was 12,983,154 kWh, and the net energy saving of 10,067,645 kWh was adjusted by multiplying Net to Gross Ratio of 77.5%.

d) Changes have made to the street light savings to show the savings separately in the work form based on the IESO Streetlight Project Verified result.

HRZ-Staff-11

Reference(s): Tab 2 of LRAMVA Work Form
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.**

Response:

a) The breakdown of the 2011 LRAMVA threshold of 28,142,000 kWh was consistent with the breakdown allocation on the EB-2014-0002 for LRAMVA disposition.

Horizon Utilities Corporation
EB-2014-0002
Exhibit 9
Tab 5
Schedule 1
Page 3 of 4
Filed: April 16, 2014

Table 9-19 – LRAMVA for 2011 - 8 months, aligning with 2011 CoS Effective Rates

	2011 OEB Approved CDM Incld in Load Forecast (A)		2011 OPA Results Eligible for LRAMVA (B)		*2011 Variances OPA Results Eligible for LRAMVA / OEB Approved CDM Incld in Load Forecast (B - A)*		2011 OEB Approved Distribution Rates		2011 LRAMVA
Customer Class:	kW	kWh	kW	kWh	*kW*	*kWh*	$ / kW	$ / kWh	$
Residential	0	8,383,777	0	4,219,156		(4,164,621)		$ 0 0142	($59,138)
GS<50	0	2,928,876	0	1,128,897		(1,799,979)		$ 0 0084	($15,120)
GS>50	1,693	7,448,680	1,556	0	(137)		$ 2.0341		($3,344)
Large User	0	0	1,462	0	1,462		$ 1.3359		$23,431
TOTAL	1,693	18,761,333	3,017	5,348,053	1,325	(5,964,600)			($54,171)

Table 9-20 – LRAMVA for 2012

Customer Class:	2011 OEB Approved CDM Incld in Load Forecast (A)		2012 OPA Q3 Results - Forecasted to Dec 31, 2012 Eligible for LRAMVA (B)		2012 Variances OPA Q3 Results - Forecasted to Dec 31, 2012 Eligible for LRAMVA / OEB Approved CDM Incld in Load Forecast (B - A)		2012 OEB Approved Distribution Rates		2012 LRAMVA
	kW	kWh	kW	kWh	kW	kWh	$ / kW	$ / kWh	$
Residential		12,575,666		3,035,014		(9,540,652)		$ 0.0143	($136,431)
GS<50		4,393,315		2,898,992		(1,494,323)		$ 0.0084	($12,552)
GS>50	2,539	11,173,019	795		(1,744)	(11,173,019)	$ 2.0459		($42,817)
Large User			543		543	-	$ 1.3436		$8,755
TOTAL	2,539	28,142,000	1,339	5,787,083	(1,200)	(22,354,917)			($183,045)

b) The 2015 LRAMVA threshold did not include actual CDM savings up to 2014. It included the incremental 2015 CDM savings. In 2015, the CDM load forecast as per below Table 3-6 referenced in the EB-2014-0002.

c) The 2015 LRAMVA threshold was referenced from EB-2014-0002 Exhibit 3 Tab 1 Schedule 2, Page 10 of 33, Table 3-6, per below.

Table 3-6 Estimated CDM Savings by Customer Class (kWh)

Year	Residential	GS < 50 kW	GS > 50 kW	Total
2014	12,575,666	4,393,315	11,173,019	28,142,000
2015	3,350,520	928,649	15,255,036	19,534,205
2016	3,103,523	846,487	15,255,036	19,205,046
2017	3,027,867	846,487	15,255,036	19,129,390
2018	3,027,867	846,487	15,255,036	19,129,390
2019	3,027,867	846,487	15,255,036	19,129,390

HRZ-Staff-12

Reference(s): 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.**

Response:

a) The effective implementation dates of the approved rate orders that correspond with Horizon RZ's rate years have been updated.

b) Based on the effective implementation dates of Horizon RZ's approved rates, the number of months entered in row 16 is accurate.

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Reference(s): Tabs 4 of LRAMVA Work Form
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.

Response:

a) A table that summarizes the allocation of program savings by year and initiative to Horizon's rate classes has been provided as an attachment, "Horizon RZ Allocation by Rate Class".

b) The IESO performs evaluations for all of its programs, which includes examining gross energy savings from the programs and the net-to-gross ratio (NTGR). From these evaluations the IESO calculates net energy savings by initiative within a program group (residential, business, industrial and low income). Peak load savings are also calculated, and reported the same way. For initiatives implemented under the Residential and Low Income Programs, they were 100% attributed to the Residential Rate Class. For initiatives implement under the Commercial and Industrial programs that apply to more than one rate class, the savings were estimated by rate class, drawing on participant-specific information where available.

Horizon Utilities 2011 Verified Results

#	Program	Results: 2011 kWh	2011 Adjustment (kWh)	2011 kW	2011 Adjustment (kW)	Allocation: Res	GS<50	GS>50	LU1	LU2	% Split: Res	GS<50	GS>50	LU1	LU2
	Residential Program														
1	Appliance Retirement	1,238,865		172		1,238,865	-	-	-	-	100%				
2	Appliance Exchange	21,438		18		21,438	-	-	-	-	100%				
3	HVAC Incentives	3,070,047	(545,322)	1,693	(298)	2,524,725	-	-	-	-	100%				
4	Conservation Instant Coupon Booklet	810,293	11,144	50	1	821,437	-	-	-	-	100%				
5	Bi-Annual Retailer Event	1,188,091	88,271	68	4	1,276,362	-	-	-	-	100%				
6	Residential Demand Response	2,830		1,093		2,830	-	-	-	-	100%				
	Sub-total - Residential Program	**6,331,564**	**(445,907)**	**3,094**	**(293)**	**5,885,657**	**-**	**-**	**-**	**-**					
	Commercial & Institutional Program														
7	Retrofit	4,805,916	615,841	857	112	-	-	514	455	-			53%	47%	
8	Direct Install Lighting	1,693,346	60,847	661	28	-	1,754,193	-	-	-		100%			
9	Building Commissioning	-		-		-	-	-	-	-					
10	New Construction	-		-		-	-	-	-	-					
11	Energy Audit	-	263,983	-	54	-	263,983	-	-	-		100%			
12	Small Commercial Demand Response	-		-		-	-	-	-	-					
13	Small Commercial Demand Response (IHD)	-		-		-	-	-	-	-					
14	Demand Response 3	20,936		536		-	-	-	-	-					
	Sub-total - Commercial & Institutional Program	**6,520,198**	**940,671**	**2,054**	**194**	**-**	**2,018,176**	**514**	**455**	**-**					
	Industrial Program														
15	Process & System Upgrades	-		-		-	-	-	-	-					
16	Monitoring & Targeting	-		-		-	-	-	-	-					
17	Energy Manager	-		-		-	-	-	-	-					
18	Retrofit	402,527		70		-	-	37	33	-			53%	47%	
19	Demand Response 3	205,346		3,498		-	-	-	-	-					
	Sub-total - Industrial Program	**607,873**	**-**	**3,568**	**-**	**-**	**-**	**37**	**33**	**-**					
	Low Income Program														
20	Home Assistance Program	-		-		-	-	-	-	-	100%				
	Sub-total - Low-Income Program	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**					
	Pre-2011 Programs completed in 2011														
21	Electricity Retrofit Incentive Program	17,700,219		3,066		-	-	1,625	1,441	-			53%	47%	
22	High Performance New Construction	1,244,589	1,668,716	242	295	-	-	537	-	-			100%		
						-	-	-	-	-					
						-	-	-	-	-					
	Sub-total - Pre-2011 Programs completed in 2011	**18,944,808**	**1,668,716**	**3,308**		**-**	**-**	**2,162**	**1,441**	**-**					
	Other														
23	Program Enabled Savings	-				-	-	-	-	-					
24	Time of Use Savings	-				-	-	-	-	-	100%				
25	LDC Pilots	-				-	-	-	-	-					
	Sub-total - Other	**-**		**-**		**-**	**-**	**-**	**-**	**-**					
	Total	**32,404,443**	**2,163,480**	**12,024**	**(99)**	**5,885,657**	**2,018,176**	**2,713**	**1,929**	**-**					

Horizon Utilities 2012 Verified Results

#	Program	Results: 2012 kWh	2012 Adjustment (kWh)	2012 kW	2012 Adjustment (kW)	Allocation: Res	GS<50	GS>50	LU1	LU2	% Split: Res	GS<50	GS>50	LU1	LU2
	Residential Program														
1	Appliance Retirement	669,778		96		669,778	-	-	-	-	100%				
2	Appliance Exchange	33,812		19		33,812	-	-	-	-	100%				
3	HVAC Incentives	1,843,136	33,877	1,091	18	1,877,013	-	-	-	-	100%				
4	Conservation Instant Coupon Booklet	56,527		9		56,527	-	-	-	-	100%				
5	Bi-Annual Retailer Event	1,082,743		60		1,082,743	-	-	-	-	100%				
6	Residential Demand Response	13,650		2,699		13,650	-	-	-	-	100%				
	Sub-total - Residential Program	**3,699,646**	**33,877**	**3,974**	**18**	**3,733,523**	**-**	**-**	**-**	**-**					
	Commercial & Institutional Program														
7	Retrofit	9,600,471	1,846,854	1,659	273	-	-	947	985	-			49%	51%	
8	Direct Install Lighting	1,875,038		550		-	1,875,038	-	-	-		100%			
9	Building Commissioning	-		-		-	-	-	-	-					
10	New Construction	1,331	224,538	-	85	-	-	85	-	-			100%		
11	Energy Audit	75,529	28,592	16	6	-	-	22	-	-			100%		
12	Small Commercial Demand Response	33		6		-	-	-	-	-					
13	Small Commercial Demand Response (IHD)	-		-		-	-	-	-	-					
14	Demand Response 3	7,718		531		-	-	-	-	-					
	Sub-total - Commercial & Institutional Program	**11,560,120**	**2,099,984**	**2,762**	**364**	**-**	**1,875,038**	**1,054**	**985**	**-**					
	Industrial Program														
15	Process & System Upgrades	-		-		-	-	-	-	-					
16	Monitoring & Targeting	-		-		-	-	-	-	-					
17	Energy Manager	479,921	5,452	60	7	-	-	67	-	-			100%		
18	Retrofit					-	-	-	-	-					
19	Demand Response 3	155,311		6,445		-	-	-	-	-					
	Sub-total - Industrial Program	**635,232**	**5,452**	**6,505**	**7**	**-**	**-**	**67**	**-**	**-**					
	Low Income Program														
20	Home Assistance Program	286,839	13,531	24	1	300,370	-	-	-	-	100%				
	Sub-total - Low-Income Program	**286,839**	**13,531**	**24**	**1**	**300,370**	**-**	**-**	**-**	**-**					

Pre-2011 Programs completed in 2011														
21 Electricity Retrofit Incentive Program	-		-		-	-	-	-	-					
22 High Performance New Construction	582,164	2,639,394	146	296	-	-	442	-	-			100%		
					-	-	-	-	-					
					-	-	-	-	-					
Sub-total - Pre-2011 Programs completed in 2011	**582,164**	**2,639,394**	**146**	**296**	**-**	**-**	**442**	**-**	**-**					
Other														
23 Program Enabled Savings	-				-	-	-	-	-					
24 Time of Use Savings	-				-	-	-	-	-					
25 LDC Pilots	-				-	-	-	-	-					
Sub-total - Other	**-**		**-**		**-**	**-**	**-**	**-**	**-**					
Total	**16,764,001**	**4,792,238**	**13,411**	**686**	**4,033,893**	**1,875,038**	**1,563**	**985**	**-**					

Horizon Utilities 2013 Verified Results

	Results				Allocation					% Split				
	2013 kWh	2013 Adjustment (kWh)	2013 kW	2013 Adjustment (kW)	Res	GS<50	GS>50	LU1	LU2	Res	GS<50	GS>50	LU1	LU2
Residential Program														
1 Appliance Retirement	373,209		57		373,209	-	-	-	-	100%				
2 Appliance Exchange	65,760		37		65,760	-	-	-	-	100%				
3 HVAC Incentives	1,639,842	95,215	974	55	1,735,057	-	-	-	-	100%				
4 Conservation Instant Coupon Booklet	311,606	953	21		312,559	-	-	-	-	100%				
5 Bi-Annual Retailer Event	694,555		48		694,555	-	-	-	-	100%				
6 Residential Demand Response	11,153		3,738		11,153	-	-	-	-	100%				
Sub-total - Residential Program	**3,096,125**	**96,168**	**4,875**	**55**	**3,192,293**	**-**	**-**	**-**	**-**					
Commercial & Institutional Program														
7 Retrofit	16,367,574	1,570,842	2,948	320	-	-	3,007	261	-			92%	8%	
8 Direct Install Lighting	1,442,489		453		-	1,442,489	-	-	-		100%			
9 Building Commissioning	-		-		-	-	-	-	-					
10 New Construction	20,831	3,201,970	6	581	-	3,222,801	-	-	-		100%			
11 Energy Audit	387,606	97,223	71	18	-	484,829	-	-	-		100%			
12 Small Commercial Demand Response	18		13		-	-	-	-	-					
13 Small Commercial Demand Response (IHD)	-		-		-	-	-	-	-					
14 Demand Response 3	9,571		597		-	-	-	-	-					
Sub-total - Commercial & Institutional Program	**18,228,089**	**4,870,035**	**4,088**	**919**	**-**	**5,150,119**	**3,007**	**261**	**-**					
Industrial Program														
15 Process & System Upgrades	-		-		-	-	-	-	-					
16 Monitoring & Targeting	-		-		-	-	-	-	-					
17 Energy Manager	178,203	(153,586)	23	(21)	24,617	-	-	-	-	100%				
18 Retrofit					-	-	-	-	-					
19 Demand Response 3	331,641		13,261		-	-	-	-	-					
Sub-total - Industrial Program	**509,844**	**(153,586)**	**13,284**	**(21)**	**24,617**	**-**	**-**	**-**	**-**					
Low Income Program														
20 Home Assistance Program	4,634,362	716,808	808	200	5,351,170	-	-	-	-	100%				
Sub-total - Low-Income Program	**4,634,362**	**716,808**	**808**	**200**	**5,351,170**	**-**	**-**	**-**	**-**					
Pre-2011 Programs completed in 2011														
21 Electricity Retrofit Incentive Program	-		-		-	-	-	-	-					
22 High Performance New Construction	-	-	-	-	-	-	-	-	-					
					-	-	-	-	-					
					-	-	-	-	-					
Sub-total - Pre-2011 Programs completed in 2011	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**					
Other														
23 Program Enabled Savings	-		-		-	-	-	-	-					
24 Time of Use Savings	-		-		-	-	-	-	-					
25 LDC Pilots	-		-		-	-	-	-	-					
Sub-total - Other	**-**		**-**		**-**	**-**	**-**	**-**	**-**					
Total	**26,468,420**	**5,529,425**	**23,055**	**1,153**	**8,568,080**	**5,150,119**	**3,007**	**261**	**-**					

Horizon Utilities 2014 Verified Results

	Results				Allocation					% Split				
	2014 kWh	2014 Adjustment (kWh)	2014 kW	2014 Adjustment (kW)	Res	GS<50	GS>50	LU1	LU2	Res	GS<50	GS>50	LU1	LU2
Residential Program														
1 Appliance Retirement	263,320		39		263,320	-	-	-	-	100%				
2 Appliance Exchange	74,996		42		74,996	-	-	-	-	100%				
3 HVAC Incentives	2,035,819	-	1,109	-	2,035,819	-	-	-	-	100%				
4 Conservation Instant Coupon Booklet	1,153,159	-	86		1,153,159	-	-	-	-	100%				
5 Bi-Annual Retailer Event	4,968,775		325		4,968,775	-	-	-	-	100%				
6 Residential Demand Response	1,510		4,457		1,510	-	-	-	-	100%				
Sub-total - Residential Program	**8,497,579**	**-**	**6,058**	**-**	**8,497,579**	**-**	**-**	**-**	**-**					
Commercial & Institutional Program														
7 Retrofit	19,282,049	-	2,594	-	-	-	2,049	545	-			79%	21%	
8 Direct Install Lighting	2,940,240		852		-	2,940,240	-	-	-		100%			
9 Building Commissioning	157,250		133		-	157,250	-	-	-		100%			
10 New Construction	521,315	-	151	-	-	521,315	-	-	-		100%			
11 Energy Audit	1,305,471	-	267	-	-	1,305,471	-	-	-		100%			

12 Small Commercial Demand Response	-		12		-	-	-	-	-							
13 Small Commercial Demand Response (IHD)	-		-		-	-	-	-	-							
14 Demand Response 3	-		595		-	-	-	-	-							
Sub-total - Commercial & Institutional Program	**24,206,325**	**-**	**4,604**	**-**	**-**	**4,924,276**	**2,049**	**545**	**-**							
Industrial Program																
15 Process & System Upgrades	-		-		-	-	-	-	-							
16 Monitoring & Targeting	-		-		-	-	-	-	-							
17 Energy Manager	1,056,692	-	41	-	1,056,692	-	-	-	-		100%					
18 Retrofit					-	-	-	-	-							
19 Demand Response 3	-		17,093		-	-	-	-	-							
Sub-total - Industrial Program	**1,056,692**	**-**	**17,134**	**-**	**1,056,692**	**-**	**-**	**-**	**-**							
Low Income Program																
20 Home Assistance Program	4,387,048	-	717	-	4,387,048	-	-	-	-		100%					
Sub-total - Low-Income Program	**4,387,048**	**-**	**717**	**-**	**4,387,048**	**-**	**-**	**-**	**-**							
Pre-2011 Programs completed in 2011																
21 Electricity Retrofit Incentive Program	-		-		-	-	-	-	-							
22 High Performance New Construction	-	-	-	-	-	-	-	-	-							
					-	-	-	-	-							
					-	-	-	-	-							
Sub-total - Pre-2011 Programs completed in 2011	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**							
Other																
23 Program Enabled Savings	-		-		-	-	-	-	-							
24 Time of Use Savings	-		2,487		-	-	-	-	-							
25 LDC Pilots	-		-		-	-	-	-	-							
Sub-total - Other	**-**		**2,487**		**-**	**-**	**-**	**-**	**-**							
Total	**38,147,644**	**-**	**31,000**	**-**	**13,941,319**	**4,924,276**	**2,049**	**545**	**-**							

Horizon Utilities 2015 Verified Results

	Results				Allocation						% Split					
	2015 kWh	2015 Adjustment in 2016 (kWh)	2015 kW	2015 Adjustment in 2016 (kW)	Res	GS<50	GS>50	LU1	LU2	SL	Res	GS<50	GS>50	LU1	LU2	SL
2011-2014+2015 Extension Legacy Framework Programs																
Residential Program																
1 Coupon Initiative	585,232	3,141	38		588,373	-	-	-	-		100%					
2 Bi-Annual Retailer Event Initiative	1,375,807		102		1,375,807	-	-	-	-		100%					
3 Appliance Retirement Initiative	86,849		13		86,849	-	-	-	-		100%					
4 HVAC Incentives Initiative	1,477,035	37,584	783	20	1,514,619	-	-	-	-		100%					
5 Residential New Construction and Major Renovation Initiative	219,469	807,475	62	42	1,026,944	-	-	-	-		100%					
Sub-total - Residential Program	**3,744,392**	**848,200**	**998**	**62**	**4,592,592**	**-**	**-**	**-**	**-**							
Commercial & Institutional Program																
6 Energy Audit Initiative	499,499	338,247	106	72	-	-	178	-	-				100%			
7 Efficiency: Equipment Replacement Incentive Initiative (Retrofit)	15,756,998	679,088	2,370	139	-	15,313,856	340	-	-			81%	19%			
8 Direct Install Lighting and Water Heating Initiative (allocation as per CDM 2016 forecast)	4,901,161		1,178	-	-	-	1,178	-	-				100%			
9 New Construction and Major Renovation Initiative (allocation as per CDM 2016 forecast)	58,323	878,463	39	364	-	-	403	-	-				100%			
10 Existing Building Commissioning Incentive Initiative (allocation as per CDM 2016 forecast)	596,676		250	-	-	-	250	-	-				100%			
Sub-total - Commercial & Institutional Program	**21,812,657**	**1,895,798**	**3,943**	**575**	**-**	**15,313,856**	**2,349**	**-**	**-**	**-**						
Industrial Program																
11 Process and Systems Upgrades Initiatives - Project Incentive Initiative (Air Liquide)	29,092,220		3,348		-	-	-	-	3,348						100%	
12 Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative	-		-		-	-	-	-	-					100%		
13 Process and Systems Upgrades Initiatives - Energy Manager Initiative (LU1)	1,382,502		116		-	-	-	116	-					100%		
Sub-total - Industrial Program	**30,474,722**		**3,464**	**-**	**-**	**-**	**-**	**116**	**3,348**							
Low Income Program																
14 Low Income Initiative	237,547	21,591	20	2	259,138	-	-	-	-		100%					
Sub-total - Low-Income Program	**237,547**	**21,591**	**20**	**2**	**259,138**	**-**	**-**	**-**	**-**							
Pilot Program																
15 Loblaws Pilot	-		-		-	-	-	-	-							
16 Social Benchmarking Pilot	2,978,654		505		2,978,654	-	-	-	-		100%					
17 Conservation Fund Pilot - SEG	-		-		-	-	-	-	-							
18 Conservation Fund Pilot - EnerNOC	-		-		-	-	-	-	-							
Sub-total - Pilot Program	**2,978,654**		**505**		**2,978,654**	**-**	**-**	**-**	**-**							
Other																
19 Efficiency:Equipment Replacement Incentive Initiative (Streetlight project)	10,067,645		-		-	-	-	-	-							100%
20 Program Enabled Savings	417,923		-		417,923	-	-	-	-		100%					
21 Adjustments to 2015 Legacy Framework Verified Results	-		-		-	-	-	-	-							
Sub-total - Other	**10,485,568**		**-**		**417,923**	**-**	**-**	**-**	**-**							
Sub-total - 2011-2014+2015 Extension Legacy Framework	**69,733,540**	**2,765,589**	**8,930**	**639**	**8,248,307**	**15,313,856**	**2,349**	**116**	**3,348**	**-**						
2015-2020 Conservation First Framework Programs																
Residential Province-Wide Program																
22 Save on Energy Coupon Program	3,913,143	388,248	252	25	4,301,391	-	-	-	-		100%					
23 Save on Energy Heating and Cooling Program	1,587,453	172,830	837	90	1,760,283	-	-	-	-		100%					
24 Save on Energy New Construction Program	-		-	-	-	-	-	-	-							
25 Save on Energy Home Assistance Program	-		-	-	-	-	-	-	-							
Sub-total - Residential Province-Wide Program	**5,500,596**	**561,078**	**1,089**	**115**	**6,061,674**	**-**	**-**	**-**	**-**							
Business Province-Wide Program																
26 Save on Energy Audit Funding Program	-	76,159	-	16	-	-	16	-	-				100%			

27 Save on Energy Retrofit Program	1,883,044	3,004,373	260	475	-	4,887,417	-	-	-			100%				
28 Save on Energy Small Business Lighting Program	-		-		-	-	-	-	-							
29 Save on Energy High Performance New Construction Program	-		-		-	-	-	-	-							
30 Save on Energy Existing Building Commissioning Program	-		-		-	-	-	-	-							
31 Save on Energy Process & Systems Upgrades Program	-		-		-	-	-	-	-							
32 Save on Energy Monitoring & Targeting Program	-		-		-	-	-	-	-							
33 Save on Energy Energy Manager Program	-		-		-	-	-	-	-							
Sub-total - Business Province-Wide Program	**1,883,044**	**3,080,532**	**260**	**491**	**-**	**4,887,417**	**16**	**-**	**-**							
Local & Regional Program																
34 Business Refrigeration Local Program	n/a		n/a		n/a	n/a	n/a	n/a	n/a							
35 First Nation Conservation Local Program	n/a		n/a		n/a	n/a	n/a	n/a	n/a							
36 Social Benchmarking Local Program	n/a		n/a		n/a	n/a	n/a	n/a	n/a							
Sub-total - Local & Regional Program	**-**	**-**	**-**		**-**	**-**	**-**	**-**	**-**							
Pilot Program																
37 Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - Conservatio	n/a		n/a		n/a	n/a	n/a	n/a	n/a							
38 EnWin Utilities Ltd. - Building Optimization Pilot	n/a		n/a		n/a	n/a	n/a	n/a	n/a							
39 EnWin Utilities Ltd. - Re-Invest Pilot	n/a		n/a		n/a	n/a	n/a	n/a	n/a							
40 Horizon Utilities Corporation - ECM Furnace Motor Pilot	n/a		n/a		n/a	n/a	n/a	n/a	n/a							
41 Horizon Utilities Corporation - Social Benchmarking Pilot	n/a		n/a		n/a	n/a	n/a	n/a	n/a							
42 Hydro Ottawa Limited - Conservation Voltage Regulation (CVR) Leveraging AMI Data Pilot	n/a		n/a		n/a	n/a	n/a	n/a	n/a							
43 Hydro Ottawa Limited - Residential Demand Response Wi-Fi Thermostat Pilot	n/a		n/a		n/a	n/a	n/a	n/a	n/a							
44 Kitchener-Wilmot Hydro Inc. - Pilot - DCKV	n/a		n/a		n/a	n/a	n/a	n/a	n/a							
45 Niagara-on-the-Lake Hydro Inc. - Direct Install Energy Efficiency Measures for the Agricultural Sect	n/a		n/a		n/a	n/a	n/a	n/a	n/a							
46 Oakville Hydro Electricity Distribution Inc. - Direct Install - Hydronic	n/a		n/a		n/a	n/a	n/a	n/a	n/a							
47 Oakville Hydro Electricity Distribution Inc. - Direct Install - RTU Controls	n/a		n/a		n/a	n/a	n/a	n/a	n/a							
48 Toronto Hydro-Electric System Limited - Direct Install - Hydronic (Pilot Savings)	n/a		n/a		n/a	n/a	n/a	n/a	n/a							
49 Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)	n/a		n/a		n/a	n/a	n/a	n/a	n/a							
50 Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)	n/a		n/a		n/a	n/a	n/a	n/a	n/a							
Sub-total - Pilot Program	**-**		**-**		**-**	**-**	**-**	**-**	**-**							
Other																
51 Adjustments to 2015 CFF Verified Results	n/a		n/a		n/a	n/a	n/a	n/a	n/a							
52 Adjustments to 2016 CFF Verified Results	n/a		n/a		n/a	n/a	n/a	n/a	n/a							
53 Adjustments to 2017 CFF Verified Results	n/a		n/a		n/a	n/a	n/a	n/a	n/a							
54 Adjustments to 2018 CFF Verified Results	n/a		n/a		n/a	n/a	n/a	n/a	n/a							
55 Adjustments to 2019 CFF Verified Results	n/a		n/a		n/a	n/a	n/a	n/a	n/a							
Sub-total - Other	**-**		**-**		**-**	**-**	**-**	**-**	**-**							
Sub-total - 2015-2020 Conservation First Framework	**7,383,640**	**3,641,610**	**1,349**	**606**	**6,061,674**	**4,887,417**	**16**	**-**	**-**	**-**						
Total	**77,117,180**	**6,407,199**	**10,279**	**1,245**	**14,309,981**	**20,201,273**	**2,365**	**116**	**3,348**	**-**						

HRZ-Staff-14

Reference(s): 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.

Response:

a) Please find attached an updated LRAMVA Work Form for Horizon RZ as a result of changes made from responses to interrogatories and also inclusive of the Final Verified 2016 Annual LDC CDM Program Results Report, recently published by IESO. The impact as a result of these changes in the LRAMVA claim is $78,044.

b) Please find attached the excel copies of Horizon's 2014 and 2015 Final CDM Annual Report, and the 2011-2015 Persistence Savings Report issued by the IESO.

HRZ-Staff-15

Reference(s): 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.

Response:

Alectra Utilities' calculated a fixed rate rider for the Residential customer class for Account 1508, Sub-account Earnings Sharing Variance Account in the Horizon Utilities RZ. A fixed rate rider of ($0.16) is presented in Table 30 – Proposed Rate Riders to Dispose of Earnings Sharing Amount – Horizon Utilities RZ. Alectra Utilities' notes that the variable rate rider shown in Table 30, is zero. Alectra Utilities' also submitted Attachment 10 – ESM Rate Rider Model_Horizon Utilities RZ which provides the detailed calculation of the ESM rate rider for the Residential class. Total ESM revenue of $426,578 for the residential class is divided by the total number of residential customers of 225,981, over 12 months, to derive the fixed rate of ($0.16).

HRZ-Staff-16

Reference(s): 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.**

Response:

a) Alectra Utilities' confirms that no entry was made in the Capital Investment Variance Account ("CIVA") since the 2016 actual capital additions were greater than the approved level. Please see Alectra Utilities' response to HRZ-Staff-3 a) for Horizon Utilities 2016 actual and approved continuity schedules.

b) Please see Alectra Utilities' response to a).

HRZ-Staff-17

Reference(s): 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.

Response:

In the Settlement Agreement for Alectra Utilities' predecessor Horizon Utilities (EB-2014-0002), the cohort ranking identified for Horizon Utilities was cohort III. Alectra Utilities' is required to update the evidence for changes to the cohort ranking, as a result of the 2017 Benchmarking Update. In the 2017 Benchmarking Update, Horizon Utilities is identified in Cohort III. As there is no change to the cohort ranking, no Efficiency Adjustment update is required.

HRZ-Staff-18

Reference(s): 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.

Response:

a) Alectra Utilities' confirms that in the Horizon RZ there were a total of 3 new Class A customers, effective July 1, 2016.

b) The IRM Model has been updated and submitted as HRZ-Staff-18_Attach 1_IRM Model Horizon Utilities RZ, to reflect 3 new Class A customers under tabs 6A. and 7A. As a result, Alectra Utilities proposes that the additional Class A customer receive an adjustment for GA and CBR allocation for the period preceding their transfer to Class A. The Class B rate riders for GA and CBR should be revised to incorporate this adjustment.

Alectra Utilities' requests disposition of its GA balance of ($77,456) and its CBR balance of ($2,060) related to its three new Class A customers and two new Class B customers (effective 23 July 1, 2016), respectively, through the bill adjustments identified in the revised IRM Model. Table 34 of Exhibit 2, Tab 1, Schedule 7 has been revised as follows to incorporate the above-mentioned changes.

Table 34 REVISED – Disposition of GA and CBR Balances – Horizon Utilities RZ

Description	Amount (Original)	Amount (Revised)
Global Adjustment - Non-RPP Class B Customers Jan 1/2016-Dec 31/2016	($2,968,042)	($2,968,042)
Global Adjustment - New Class A Customers July 1/2016	($47,208)	($54,671)
Global Adjustment - New Class B Customers July 1/2016	($22,785)	($22,785)
Class B Non-RPP Customers Only - GA Rate Rider/Bill Adjustment	($3,038,034)	($3,045,498)
Capacity Based Recovery - Non-RPP Class B Customers Jan 1/2016-Dec 31/2016	($186,982)	($186,982)
Capacity Based Recovery - New Class A Customers July 1/2016	($1,256)	($1,454)
Capacity Based Recovery - New Class B Customers July 1/2016	($606)	($606)
Class B Non-RPP Customers Only - CBR Rate Rider/Bill Adjustment	($188,843)	($189,042)

The disposition of Class B GA and CBR balances through rate riders, which was provided in Exhibit 2, Tab 1, Schedule 7, Table 37, has been revised below.

Table 37 REVISED – Disposition of GA and CBR Balances – Horizon Utilities RZ

Customer Class	Global Adjustment Rate Rider Non-RPP Class B Jan 1 - Dec 31, 2016 ORIGINAL		CBR Rate Rider Class B Consumer Jan 1 - Dec 31, 2016 ORIGINAL		Global Adjustment Rate Rider Non-RPP Class B Jan 1 - Dec 31, 2016 REVISED		CBR Rate Rider Class B Consumer Jan 1 - Dec 31, 2016 REVISED	
	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW
RESIDENTIAL	(0.0018)		(0.00005)		(0.0018)		(0.00005)	
GENERAL SERVICE < 50 KW	(0.0018)		(0.00005)		(0.0018)		(0.00005)	
GENERAL SERVICE > 50 KW	(0.0018)			(0.01721)	(0.0018)			(0.01719)
LARGE USE (1)	(0.0018)			(0.02598)	(0.0018)			(0.02595)
LARGE USE (2)	0.0000			0.00000	0.0000			0.00000
UNMETERED & SCATTERED LOADS	(0.0018)		(0.00005)		(0.0018)		(0.00005)	
SENTINEL LIGHTS	(0.0018)			(0.01728)	(0.0018)			(0.01727)
STREET LIGHTING	(0.0018)			(0.01717)	(0.0018)			(0.01715)

HRZ-Staff-19

Reference(s): 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.**

Response:

a) Alectra Utilities' clarifies that the total amount to be disposed of by rate rider is ($7,298,317) as presented in Table 36 – Group 1 Disposition by Customer Group – Horizon Utilities RZ. No change is required to the Group 1 balances.
b) Alectra Utilities' clarifies that the debit amount of $588,675 under IRM 14 shown for Account 1588, should have been shown for Account 1595. Alectra Utilities' confirms that this is a typo in Table 36 – Group 1 Disposition by Customer Group – Horizon Utilities RZ. Attachment 6b – IRM Model Horizon Utilities RZ, Tab 3. Continuity Schedule, accurately presents the residual balance in Account 1595 as $588,675. This residual 1595 balance is being disposed to all customer classes.
c) The calculation of the rate rider for 'All Customers – DVA Rate Rider 1' is provided in Exhibit 3, Tab 1, Schedule 1, Attachment 6b – IRM Model Horizon Utilities RZ, Tab 8. Calculation of Def-Var RR. The rate rider calculations included in this tab relate to both the 'All Customers – DVA Rate Rider 1' and 'All customers ex WMPs – DVA Rate Rider 2'.

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.

Response:

Please see Alectra Utilities' response to G-Staff-1.

HRZ-Staff-21

Reference(s): 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.

Response:

1) In booking expense journal entries for Charge Type 1142 (formerly 142), and charge type 148 from the IESO invoice, the Horizon Utilities RZ used approach a) above.

2) a) With regards to the balances in Account 1589 as at December 31, 2016, the revenues, expenses and true-ups related to RPP settlements are based on estimates/accruals at year end.

b) Alectra Utilities' does not have any reconciling amounts recorded under items and 1a and 1b of the GA Analysis Workform, and has not included any adjustment to Account 1589 in the DVA Continuity Schedule for the Horizon Utilities RZ.

3) a) With regards to the balances in Account 1588 as at December 31, 2016, the revenues, expenses and true-ups related to RPP settlements are based on estimates/accruals at year end.

b) Alectra Utilities' has included an adjustment to Account 1588 in the DVA Continuity Schedule which relates to item (i) Revenues, as unbilled revenues were trued up based on actual consumption for the true-up period (August to December 2016) in the first five months of 2017. The total amount of this true-up was a credit of $988,885 for the Horizon Utilities RZ.

c) The credit adjustment of $988,885 shown in the column "Principal Adjustments During 2016" for Account 1588 represents RPP settlement true-up claims pertaining to the August to December 2016 but settled with the IESO in January to May of 2017. This adjustment aligns with the guidance provided by the OEB in a letter dated May 23, 2017 titled "*Guidance on the Disposition of Accounts 1588 and 1589*" in which the OEB states:

"The balances in distributors' RSVA Power (1588) and Global Adjustment (1589) variance accounts that are requested for disposition by distributors must reflect RPP settlement amounts pertaining to the period that is being requested for disposition. This means that RPP settlement true-up claims made with the IESO in the period subsequent to the fiscal year for which disposition is being requested must be reflected in the balances being requested for disposition."

PRZ-Staff-1

Reference(s): 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."

Response:

Alectra Utilities' ensured that annual consumption was used when determining the 10th percentile level, i.e. 12 months of consumption on the account. Accordingly inactive accounts and accounts that were active for only a part year were excluded. This is what is meant by "active residential customers who consumed electricity at the location for a minimum of twelve months."

PRZ-Staff-2

Reference(s): 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.

Response:

Alectra Utilities' would not change its application based on this information.

As shown in PowerStream Inc.'s 2016-2020 Custom IR rate application (EB-2015-0003) filed May 22, 2015, Section VI, Tab 30, Schedule 1, Page 2 of 7 (reproduced below), the amount of $266,079 represents the recovery of an investment in renewable energy net fixed assets of $2,394,161 over the life of these assets.

In the absence of the Green Energy Plan Electricity and Rate Protection Benefit and Charge, these assets would have been added to rate base in PowerStream's 2017 cost of service rate application without a materiality threshold. As these were not added to rate base, there is no funding to recover the remaining investment of $2,394,161and no way for Alectra Utilities' to mitigate this cost.

PRZ-Staff-3

Reference(s): 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

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.

Response:

The current application before the OEB for the PowerStream RZ is a one-year Incremental Capital Module ("ICM") for electricity distribution rates ("EDR") effective January 1, 2018; whereas the referenced Decision and Order relates to PowerStream's Custom IR Application (EB-2015-0003) for EDR effective January 1, 2016 to December 31, 2020. While both rate applications follow the OEB's October 2012 *Report of the Board: Renewed Regulatory Framework for Electricity: A Performance Based Approach* ("RRFE", now "RRF"), the threshold for customer engagement is different. Notably, customer engagement for ICM applications does not specifically require customer input into the development of the business plans. The *Filing Requirements for Electricity Distributors and Transmitters: Chapter 5 Consolidated Distribution System Plan Filing Requirements* at page 8 that the "*The Board may also require a*

DS Plan to be filed in relation to leave to construct, Incremental Capital Module or Z-factor applications". Further, customer engagement for ICM applications looks only at capital investments, whereas for a rebasing application it looks at both capital and OM&A.

That notwithstanding, in light of the OEB's Decision regarding the PowerStream Custom IR Application, Alectra Utilities has made the following changes to the way in which it approaches customer engagement:

Scope of Customer Consultation: In the 2014-15 PowerStream customer engagement, n=1,533 low-volume customers provided input on the proposed plan through the online feedback portal vs. n=7,093 for the present application. Additionally, GS > 50 kW customers were surveyed by telephone in the PowerStream RZ in the present application; an approach not undertaken in the 2014-15 PowerStream customer engagement. This broader rate-class coverage has provided for a more complete understanding of customer needs and preferences in the PowerStream RZ.

Customer Expectations: Unlike the 2014-15 PowerStream customer engagement, Alectra Utilities' customer engagement included a focus on the *customer journey touchpoints* and *customer outcomes*. The purpose of this new focus was to help Alectra Utilities set priorities that are aligned with customer expectations in the PowerStream RZ.

Customer Preferences and Trade-offs: The 2017 customer engagement sought greater customer input on the trade-offs associated with individual capital project investments. This approach presented customers with the immediate need for project investments, addressed the associated project costs and bill impact, and asked customers to consider the trade-offs between reliability and costs related to these projects.

While the 2014-15 customer engagement presented customers with the need for project investments, it did not adequately seek customer input on the trade-offs between costs and reliability associated with individual groups of investment projects (i.e. rear-lot conversion, underground cable replace, etc.). Instead, customers were asked to provide feedback on the proposed capital investment and OM&A plan in aggregate through a single ballot question. In hindsight, this “all-or-nothing” approach to the trade-offs between costs and reliability was not adequate in providing useful input into the development of PowerStream’s business plan and overall Custom IR rate application.

In contrast, the 2017 approach to customer engagement clearly articulates the value proposition of individual proposed capital projects and better balances customer concerns with the costs and reliability associated with these projects.

PRZ-Staff-4

Reference(s): E2/T3/S10, p.13, Table 98

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	Rate Class		
		Residential (750kWh)	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.

Response:

Yes, information on an individual project basis was provided for each project category in the Online Feedback Portal. Details of these projects can be found on pages 42-45 of Appendix 5.0 – Alectra Utilities Online Feedback Portal Layout.

Additionally, in the Telephone Surveys, PowerStream RZ customers were provided the opportunity to learn more about how the request for increased rates was going to be invested. *Page 18 - Appendix 2.0 – PowerStream Telephone Survey Report* indicates that 25% of Residential PowerStream RZ customers sought this additional information. In total, 58% of PowerStream RZ Residential customers were provided a detailed breakdown of proposed investments (See pages 21-25 of Appendix 2.0 for detailed findings).

PRZ-Staff-5

Reference(s): 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.**

Response:

a) Alectra Utilities' completed an assessment of the reliability impact for the three scenarios presented in the Customer Engagement for customer input and feedback. The scenario that the level of reliability would eventually decline was assessed under the approach 50% of the proposed ICM projects would be approved. The assessment of the impact was over the five year period 2018-2022. The term decline was determined relative to the intent to maintain the overall system reliability levels which the proposed ICM projects are expected to achieve.

   Table 1 identifies the ranges of reliability declining impacts assessed under each scenario in SAIDI minutes for the PowerStream rate zone.

b) The scenario that the level of reliability would decline significantly was assessed under the approach that none of the ICM projects would be approved, hence there was no bill impact provided for this scenario.

Table 1 – Assessment of Reliability Impact for Scenarios for SAIDI (minutes) for

Year	Reliability Eventually Declines	Reliability Could Decline Significantly
2018	2.86 - 3.01	5.79 - 6.08
2019	3.01 - 3.16	6.08 - 6.39
2020	3.16 - 3.32	6.39 - 6.71
2021	3.32 - 3.48	6.71 - 7.04
2022	3.48 - 3.80	7.04 - 7.54

Table 2 identifies the ranges of reliability declining impacts assessed under each scenario in SAIDI % relative to 2016 levels.

Table 2 – Impact to Reliability in terms of SAIDI % (relative to 2016)

Year	Reliability Eventually Declines	Reliability Could Decline Significantly
2018	5.43% - 5.70%	10.98% - 11.53%
2019	5.70% - 5.99%	11.53% - 12.11%
2020	5.99% - 6.29%	12.11% - 12.71%
2021	6.29% - 6.60%	12.71% - 13.35%
2022	6.60% - 7.21%	13.35% - 14.29%

Alectra Utilities' completed the assessment of reliability impact for the PowerStream rates zone using a two-step method. The number of asset failures (Customer Interruptions) was projected based on the historical failure rates and the number of assets considered to be replaced. The approximate numbers of customers impacted by each interruption due to the failure of the asset was estimated based on asset type. The duration of each outage due to the asset failure was estimated from historical experience. The CMI was determined from the product of each projected number of failures, number of customers impacted by each outage from failure and the minutes of each outage interruption. In order to determine the low and high scenario the failure rate was increased by 5% to project an escalating failure trend.

Once the CMI values were determined, the second step in the assessment included the conversion of Customer Minutes of Interruption to the System Average Interruption Duration Index (SAIDI) which was determined by diving the CMI impact by the total number of customers in the PowerStream rate zone. For the assessment, 369,317 customers were considered.

PRZ-Staff-6

Reference(s): 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.

Response:

a) PowerStream revised its 2018 capital forecast based on the nature of the feedback received from customers. More specifically, PowerStream considered customer preferences in respect of the type of investments proposed. In both the Online Feedback Portal and Telephone Surveys, there was marginally less support for System Renewal investments amongst PowerStream RZ customers compared to System Service investments. In the PowerStream RZ telephone survey, 48% of Residential customers in the PowerStream RZ selected "*I am not willing to accept any additional charges knowing that the level of reliability could decline significantly*" with regards to System Renewal investments [Customer Engagement Report, Page 26].

In total, 7,093 PowerStream RZ customers completed the Online Feedback Portal, which offered an explanation of the key infrastructure challenges and proposed solutions related to aging infrastructure pressures. The table below provides that explanation. [Appendix 5.0, page 45, Alectra Utilities Online Feedback Portal Layout]

Key Infrastructure Challenges	Proposed Solution
Underground cables are an important component of the power distribution system. Their failure causes long outages that can affect a large number of customers. Because the cables are underground, fixing them when they fail is time consuming and expensive. Cable failures are the leading cause of outages at PowerStream.	PowerStream will replace underground cables identified as a high risk of failure proactively, before they fail. Cables which are in poor condition, are unfit for rehabilitation and contribute to a high number of outages will be prioritized for replacement first. Upon replacing the cables, PowerStream will also update the affected section of the distribution system to present day standards.
There are many neighborhoods in the PowerStream service area that are supplied with electricity through overhead distribution lines and poles located in backyards. These overhead distribution lines are in poor condition and experience more frequent and longer outages as crews making repairs have difficulty in obtaining access to the equipment in backyards.	PowerStream will convert backyard overhead supply services to underground services at the front of the home as per present day standards. Neighbourhoods will be selected and prioritized for conversion based on the condition of the assets, risks related to environmental, health and safety issues as well as reliability impacts. With services located at the front of the home, ongoing maintenance will be more efficient and therefore less costly.
Electrical stations house large power transformers and main switches required to distribute electricity to where it is needed. They connect the main lines and can service up to 40,000 customers per station. Since failures at stations affect a large number of customers and have the risk of long outages, PowerStream needs to proactively replace station equipment that is in poor condition, obsolete or has a history of failure, in order to avoid negatively impacting reliability.	PowerStream will replace essential station equipment that is in poor condition, obsolete or with history of failure on a proactive basis. The priority in 2018 is replacing obsolete main switches at the Richmond Hill station that have a history of failure and obsolete main switches at a Bradford substation that are in poor condition.

Ultimately, this, in addition to customer feedback which identified electricity rates as the top priority, contributed to the above revision to Alectra Utilities' ICM request.

b) The views of customers directly affected by the removal of the Rear Lot Supply Remediation project at Queen/Greenway were captured through the telephone surveys conducted as part of customer engagement described in the application.

The telephone surveys in the PowerStream RZ used a stratified random sampling approach based on known characteristics of customers including region and consumption by rate class (residential, GS<50kW and GS>50kW). This sample is representative of the PowerStream RZ. Therefore, a representative sample of customers in each region (Aurora, Barrie, Bradford, Markham, Richmond Hill, Vaughan and Other) were included in the customer engagement process. This includes the Queen/Greenway customers.

PRZ-Staff-7

Reference(s): 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.**

Response:

a) Please see list of new projects that were not included in the DSP

The following four projects are new projects which were not included in the DSP

1) Road Authority YRRT Yonge Street
2) Rear Lot Supply Remediation – Royal Orchard – North
3) Cable Replacement – (M49) – Steeles and Fairway Heights
4) Cable Replacement – (V08) – Steeles Ave and New Westminster

1. Road Authority YRRT Yonge Street

On May 22, 2015, PowerStream submitted its rate application. The projects included in the DSP were corresponding to information from 2014. YRRT had not identified these projects in 2014. However, subsequent to the application, Alectra Utilities was informed of further enhancements to the transportation infrastructure and expansion on several Rapid Transit corridors. These were brought to the attention of the OEB during the custom IR proceedings and noted in the rate decision. (Refer to EB-2015-003, Page 14- excerpt included below)

PowerStream suggested that any reduction to its capital spending program was inappropriate, but that a reduction of $23.22 million was feasible, except that an additional $20.00 million may be needed for York Region Rapid Transit project (Refer EB-2015-003, Page 14).

2. Rear lot and Cable Replacement Projects

The rear lot and the cable replacement projects were previously carried out as annual programs. Following the Board decision EB-2015-0003 where the Board expressed concerns regarding PowerStream's Underground Cable Replacement Program especially related to the cost of the program. To address the concerns raised by the Board, PowerStream undertook a review of the rear lot and cable replacement programs. The review identified that the under an annual program structure, the initiatives lacked the project management structure, rigour and accountability of project discipline. Alectra Utilitis in the PowerStream rate zone has since restructured the initiatives and treats each rear lot and cable replacement as a distinct and separate project with a defined scope, schedule and cost that addresses a discrete driver. Table below summarizes the modifications including any changes in the timing and amounts of cost recovery from the DSP to the present application.

Project	DSP Timing	DSP Capital Expenditure	ICM Timing	ICM Capital Expenditure	Notes
Station Switchgear Replacement (ACA) 8th Line MS323	2017-2018	$1,519,005	2017-2018	$1,394,991	(1)
Planned Circuit Breaker Replacement - Richmond Hill (Lazenby) TS#1 - Second Bus	2019	$1,119,281	2018	$1,186,729	(2)
Rebuild 27.6kV Poleline on Warden Avenue into 4 ccts from 16th to Major Mack	2017	$2,050,441	2018	$1,372,976	(3)
Mill Street MS835 TX Upgrade - Tottenham	2016-2018	$5,993,032	2018	$1,298,572	(4)
Build 2 ccts pole line on 19th Ave from Leslie St to Bayview Ave	2017	$1,221,747	2018	$1,202,306	(5)
Double Circuit Existing 23M21 Circuit from Bayfield & Livingstone to Little Lake MS	2019	$2,395,509	2018	$1,276,180	(6)

Notes –

(1)- The cost estimate has decreased because the original estimate was based on AIS switchgear whereas the plans are now to install Siemens GIS switchgear which is less expensive.

(2) The start date for the circuit breaker replacement at Richmond Hill (Lazenby) TS#1 has been advanced by one year. Urgency has increased due to the failure of the M8 circuit breaker in May 2016. The cost estimate has increased $68k primararily due to higher equipment cost.

(3) The project had been deferred from 2017 to 2018 based on the progress of the Markham Future Urban Area (FUA) development.

The estimate in the DSP was based on replacing all existing poles with new 4 ccts poles. York Region has widened Warden Ave from 2 lane to 4 four lanes recently. Some poles were replaced under the road authority project. Therefore, the new estimate is lower than the estimate in the DSP.

(4) The DSP submission was for a new 2x5MVA, 44-8.32kV, 3 feeder municipal substation with land purchase in 2016, design and equipment procurement in 2017, and construction in 2018 at a total budget expenditure of $5,993,032. Following the DSP submission it was confirmed that only land available in the Tottenham area was at the edge of the service area. The potential substation location would result in a radial supply to the substation and would require a dual pole line along Mill Street in order to ensure reliability for the 8.32kV feeder integration.

Due to unavailability of land, an alternative solution was identified to place an additional substation transformer on existing MS835 and creating a triad configuration for substations in

Tottenham. Further review of the existing substation indicated that the leased land could not accommodate an additional transformer however the lands could accommodate an upgrade of the existing 6MVA transformer to a 10MVA transformer with a Contingency Maximum Load rating of 15.2MVA.

Upgrading the station transformer would avoid a radially supplied substation with dual pole line integration as well as avoiding the purchase of the land and is cost effective solution to meet the medium term load requirements.

The scope of the project was changed from purchasing vacant land and constructing a new 2x5MVA substation to upgrading the existing station transformer on leased land from 6MVA to 10MVA at a capital expenditure of $1,298,572, as per the ICM submission.

(5) The project had been deferred from 2017 in the DSP to 2018 based on the progress of the Leslie North development.

(6) The DSP submission was for a $2,395,509 capital expenditure in 2019 for double circuiting of the 23M21 with the 23M28 from Bayfield & Livingstone to Cundles & Duckworth and transferring Little Lake MS306 from 23M21 to 23M28 to provide supply for the new 20 MVA substation; Livingstone MS310.

Following the DSP submission, a contingency analysis of stations MS306 and MS310 was performed and it was discovered that both the stations could not be supplied from the 23M21 feeder since they would not provide reliable supply during a contingency condition. Furthermore, it was optimal to coordinate the completion of any pole line work in-front of the new substation at the same time as the new substation is being constructed, rather than have crews return the following year to rebuild the newly installed riser poles and adjacent pole line. From scheduling and resource perspective, it was determined to change the project from a single year construction into two year duration.

As a result, the timing of the construction was changed from single year in 2019 to be completed in two phases from 2017 and 2018. Phase 1(Livingstone MS inclusive) to be constructed in 2017 to coincide with the construction of Livingstone MS, and Phase 2 (east of Livingstone MS to the existing Little Lake MS306) to occur in 2018.

The capital expenditure in the ICM submission for 2018 was $1,276,180; corresponding to the construction of Phase 2 east of Livingstone MS. Phase 1 costs were incurred and capitalized in 2017.

c) Project summary reports are filed under PRZ-Staff 7c_Attach 1. The attachments can also be found under EB-2015-0003, Exhibit G, Tab 2, Appendix A: Project Investment Summaries.

d) Each of the projects for which Alectra PowerStream RZ is seeking ICM funding has a distinct driver and system need that each project will fulfill and the timing established based on the system needs. Furthermore, each of the proposed ICM projects satisfies the eligibility criteria of materiality, need and prudence. Each of these projects have been evaluated against a set of consistent value framework and have been optimized for the 2018 budget year based on system needs considering value and risk and through properly pacing the investments. Each of the rear lot and cable replacement project is treated as discrete project with specific driver, timing and scope. Alectra PowerStream (RZ) has used the same optimization methodology as referred in EB-2015-0003 Exhibit G, Tab 2, 5.3.5. Asset Lifecycle Optimization Policies and Procedures, Page 16 for the ICM projects for evaluation of these projects.

PRZ-Staff-8

Reference(s): 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.

Response:

a) The current projection of annual savings resulting from the merger over the deferral period is provided in Table 1. This is consistent with the synergy forecast provided in the Mergers, Acquisitions, Amalgamations and Divestitures ("MAADs") Application filed by Enersource Hydro Mississauga, Horizon Utilities Corporation and PowerStream Inc. on April 15, 2016 (EB-2016-0025). Investments related to merger transitional costs and synergies for general plant expenditures are included in Table 1.

Table 1- Total Net Synergies

($MMs)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Gross Synergies											
Operating	7.2	20.1	31.7	40.6	42.5	42.5	42.5	42.5	42.5	42.5	354.6
Capital	23.0	22.6	28.8	23.2	30.0	8.0	8.0	8.0	8.0	8.0	167.6
Total Synergies	30.2	42.7	60.5	63.8	72.5	50.5	50.5	50.5	50.5	50.5	522.2
Transition Costs											
Charged to Operating	20.9	11.1	8.2	2.3	0.5	-	-	-	-	-	43.0
Charged to Capital	33.7	15.2	4.4	-	-	-	-	-	-	-	53.3
Total Transition Costs	54.6	26.3	12.6	2.3	0.5	-	-	-	-	-	96.3
Net Synergies											
Operating	(13.7)	9.0	23.5	38.3	42.0	42.5	42.5	42.5	42.5	42.5	311.6
Capital	(10.7)	7.4	24.4	23.2	30.0	8.0	8.0	8.0	8.0	8.0	114.3
Total Net Synergies	(24.4)	16.4	47.9	61.5	72.0	50.5	50.5	50.5	50.5	50.5	425.9

b) Please see Alectra Utilities' response to part a).

c) Please see Alectra Utilities' response to PRZ-AMPCO-4.

PRZ-Staff-9

Reference(s): 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.

Response:

For the following two Cable Replacement projects, the budget estimates were compiled based on the individual project scope and cost experience from very similar 2017 Cable Replacement projects.

- Cable Replacement – (M49) – Steeles and Fairway Heights
- Cable Replacement – (V08) – Steeles Ave and New Westminster

Alectra Utilities’ predecessor PowerStream used a cable replacement “unit cost” concept (expressed as dollars per metre of cable replaced) in developing high level overall project cost estimates.

PowerStream realized that for cable replacement projects, due to the nature of the work and unique scope of each project, cost estimates based on a dollar per metre cable replacement unit cost were not as accurate as estimates developed based on the specific project designs.

Cable replacement project costs depend on many factors and details specific to each project. One example is the method of construction which may utilize directional bore (less expensive) or open cut trench (more expensive). This approach is dependent on available space and clearance from other utilities such as gas, water, telecommunication, and other obstructions. Another example is the location of the cable run which could be on the boulevard (less expensive), or under the roadway crossing the street (more expensive because concrete encased duct bank is required).

Cable Replacement project costs are therefore estimated based on each project’s details.

To ensure cost controls during implementation, Alectra Utilities) has implemented a cost review at each project stage: final design (difference in estimate from preliminary design estimate) and during each construction stage. Appropriate internal controls have been implemented to monitor and approve project expenditures.

PRZ-Staff-10

Reference(s): 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.

Response:

Following the OEB decision on PowerStream's 2016 to 2020 rate application (EB-2015-0003), Alectra Utilities further analyzed the impact of the rear lot project on customer reliability during the 2013 Ice storm and completed an alternative options analysis for conversion of each location, to recommend one of the four options as presented in EB-2015-0003.

Reliability Impact:

For the PowerStream rate zone, the ice storm of December 2013 caused a total of 178,831,919 CMI (Customer Minutes of Interruption) in the system. The rear lot grids accounted for 29,831,573 CMI, which represents 16.68% of the total CMI during the ice storm.

Options Analysis

PowerStream analyzed each location with respect to the following four options and completed additional analysis.

The four Options to address rear lot services include:

Option1 – Replace existing rear lot with new rear lot overhead (primary and secondary)

Option 2 – Replace existing rear lot with new front lot overhead (primary and secondary)

Option 3 – Replace existing rear lot with new Hybrid design where underground primary (primary cables and padmount transformers) is installed in the front lot, and overhead secondary (poles and secondary conductors) is installed in the rear lot

Option 4 – Replace existing rear lot with new front lot underground (primary and secondary)

The following cost items are considered during the additional analysis:

• Initial installation cost
• Frequency of failure
• Consequence of failure
• Risk cost (failure probability x consequence cost)
• Maintenance cost
• Customer Minutes of Interruption (CMI)

Based on the additional analysis as well as locational consideration, the following design options are now being considered for the 35 rear lot locations that exist within the PowerStream rate zone, instead of converting all rear lot construction to front lot underground supply.

Design Option Breakdown				
Option 1 - Rear OH	Option 2 - Front OH	Option 3 - Hybrid	Option 4 - Front UG	Total Locations
4	2	2	27	35

Customer Communication

During the first phase of conversion in March 2015, PowerStream issued letters to all impacted customers followed by an open house session in June 2015.

For the second phase of the conversion, letters were also issued to all impacted customers. Due to low attendance at the open house during the first phase, for the second phase of work, PowerStream elected to provide customers with a video on PowerStream's website to explain the scope of work, methods for customer feedback and benefits.

Cost Concerns

Alectra Utilities has now completed two projects where the rear lot supply service has been converted into the front lot underground service and has a better understanding and experience of each of the options. The budget costs are now based on the actual experience of completing the conversion of rear overhead to front underground and preliminary design.

To ensure cost control during implementation, Alectra Utilities has implemented a cost review at each project stage: final design (difference in estimate from preliminary design estimate) and as well as during each construction stage. Appropriate internal controls have been implemented to monitor and approve project expenditures in the PowerStream Rate Zone.

PRZ-Staff-11

Reference(s): 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."

Response:

a) The statement as provided in evidence was a typo that should have stated:

"Each project is distinct, unrelated to recurring annual capital **program**, and has been evaluated in the asset management and capital planning process as required in 2018." (Emphasis added)

None of the ICM Proposed projects for the PowerStream rate zone for the three investment categories of System Access, System Renewal and System Service are related to a recurring annual capital program.

Alectra Utilities' distinguishes between multi-year projects from typical annual capital programs. Multi-year projects are larger complex projects that are paced over several years with a defined scope, budget and end date. Phases of multi-year projects may be staged to meet the requirements of the municipality, region or road authority as is the case with the YRRT project.

Examples of capital investments which are part of recurring annual capital programs are as follows:

System Access:

1. New Residential Subdivision Development – North
2. New Residential Subdivision Development – South
3. New Subdivision Development – Secondary Service Lateral - South

Program investment is required in the PowerStream rate zone to meet mandatory obligations of connecting new subdivisions and developments. The scope and schedule of these investment is not within the control of Alectra Utilities. Alectra Utilities cannot pace or defer these investments to connect new developments and subdivisions. Developers and customers in the PowerStream rate zone determine the area, scope and schedule of each connection, Alectra Utilities works collaboratively with such developers to ensure connections are made within the prescribed timelines set by codes and regulations.

System Renewal:

1. Storm damage – Replacement of distribution equipment due to storm.
2. Switchgears – Unscheduled Replacement of Failed (End of Useful Life) Distribution Equipment.

Program investment is required in the PowerStream rate zone to replace failed equipment such as failed switchgears as well as equipment damaged from weather related storms. This investment program is necessary to maintain a safe and reliable electrical infrastructure and to restore customers from sustained outages. The scope and schedule of these investment is not within the control of Alectra Utilities. Alectra Utilities cannot pace or defer these investments to replace failed equipment. Alectra Utilities cannot predict the area, magnitude and timing of each storm or the location of the specific switchgear unit will fail.

System Service

None of the projects in the system service are considered as related to a recurring annual capital programs.

b) Each proposed eligible capital project has been determined to be required and necessary in 2018 based on the asset management and capital planning process used by Alectra Utilities for the PowerStream rate zone. The asset management planning process, as identified in Sections 5.3.1 – Asset Management Process Overview and 5.4.2 – Capital Expenditure Planning Process Overview in PowerStream's DSP (EB-2015-003/SII/ExG/Tab2).

For each of the proposed projects, the investment drivers, needs and timing has been evaluated through business cases, determined to provide customer value and has been prioritized, paced and optimized to be included in the 2018 capital budget portfolio.

PRZ-Staff-12

Reference(s): 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.

Response:

a) The business case for each project identifies the options considered for each project. Please refer to Alectra Utilities' response to G-Staff-3 for specific page references in Attachment 33.

b) For projects that have feasible alternative, the cost for the options is indicated in the corresponding business case in Attachment 33. Please refer to Exhibit 3. Tab 1, Schedule 1, Attachment 33 – ICM Business Cases PowerStream RZ, p. 49, 61 and 62.

PRZ-Staff-13

Reference(s): 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.

Response:

a) The reconciliation of the approved CDM reduction of 245,751,229 kWh and the LRAMVA threshold of 137,099,754 kWh is derived from the following table which was filed in PowerStream's 2013 Cost of Service Application in Undertaking JT1.1, as Table JT1.1-1 CDM Savings Breakdown by Component.

Year	OPA Programs	3rd Tranche	CDM Targets 2011-2014	Total CDM Savings
2005	0	3,130,723	0	**3,130,723**
2006	23,745,838	24,080,564	0	**47,826,403**
2007	37,320,287	33,881,792	0	**71,202,078**
2008	74,910,984	33,568,782	0	**108,479,766**
2009	118,966,981	0	0	**118,966,981**
2010	125,158,173	0	0	**125,158,173**
2011	114,674,894	0	14,637,000	**129,311,894**
2012	112,573,489	0	63,374,000	**175,947,489**
2013	112,089,533	0	141,438,000	**253,527,533**

The approved 2013 CDM reduction of 245,751,229 kWh consists of persistence of savings from the earlier OPA programs and savings from the newer CDM Targets 2011-2014 as summarized in the table 1 below.

Table 1: PowerStream 2013 CDM Adjustment to Load Forecast (kWh)

	OPA Programs	CDM Targets 2011-2014	Total
Adjustment to kWh purchases	112,089,533	141,438,000	253,527,533
Loss factor	1.03164	1.03164	1.03164
Adjustment to billing determinants	108,651,476	137,099,754	245,751,230

The reported OPA programs savings of 112,089,533 kWh were final and not subject to change. Alectra Utilities' did not include this amount in both the LRAMVA threshold and the actual savings as there will be no variance and no impact on LRAMVA for the PowerStream RZ.

Alectra Utilities' has calculated LRAMVA by comparing the forecasted CDM Targets 2011-2014 of 137,099,754 kWh built into 2013 rates with the actual savings reported by the IESO for those programs.

b) The 2013 load forecast was based on a regression model that forecasted load on a pre-CDM savings basis derived from actual kWh purchases with known CDM savings added back. Accordingly, the 2013 load forecast before the CDM adjustment was not reduced by 2011 actual savings.

PRZ-Staff-14

Reference(s): 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

Response:

a) Alectra Utilities' clarifies that the LRAMVA workform submitted for the PowerStream Rate Zone included the full year of results provided by the IESO. The note referencing a change to the formulas in the LRAMVA workform was included in error. Alectra Utilities' confirms that the savings included in the IESO verified reports for 2014 and 2015, and persistence reports, were used to calculate the LRAMVA for the PowerStream Rate Zone. Alectra Utilities' relied on the Ontario Energy Board's 2012 CDM Guidelines, 2015 CDM Guidelines and 2016 Updated Policy for the calculation of LRAMVA in respect of peak demand savings. Alectra Utilities' did not include peak demand savings from demand response programs in its lost revenue calculation, in accordance with the 2016 Updated Policy.

b) Please see Alectra Utilities' response to part a).

c) Please see Alectra Utilities' response to part a).

d) Please see Alectra Utilities' response to part a).

PRZ-Staff-15

Reference(s): 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.**.

Response:

c) Please refer to PRZ-Staff-21 where Alectra Utilities' filed an updated LRAMVA work form as a result of its responses to interrogatory. Alectra Utilities' updated row 14 in Table 3 to include the effective implementation dates of the approved rate orders that correspond with PowerStream's rate years.

d) Alectra Utilities' revised the number of months entered in rows 16 and 17 to correspond with the effective implementation dates of the approved rate orders. An updated LRAMVA work form is filed in the response to PRZ Board Staff-21.

PRZ-Staff-16

Reference(s): 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)**

Response:

a) Tables summarizing the allocation of program savings by initiative to PowerStream RZ's rate classes within each year (2011 through 2015) are presented below.

Table 1: Allocation of 2011 Programs

Program	Rate Allocations for LRAMVA			
	Res	GS<50	GS>50	Total
Consumer Program				
Appliance Retirement	100.00%			100%
HVAC Incentives	100.00%			100%
Conservation Instant Coupon Booklet	100.00%			100%
Retailer Co-op	100.00%			100%
Residential Demand Response	0.00%			0%
Residential New Construction	100.00%			100%
Business Program				
Retrofit		21.00%	79.00%	100%
Direct Install Lighting		100.00%		100%
New Construction			100.00%	100%
Energy Audit			100.00%	100%
Demand Response 3				0%
Industrial Program				
Retrofit			100.00%	100%
Demand Response 3				0%
Pre-2011 Programs completed in 2011				
Electricity Retrofit Incentive Program		0.41%	21.14%	22%
High Performance New Construction			17.00%	17%
Multifamily Energy Efficiency Rebates		27.10%		27%
LDC Custom Programs (Data Center Incentive Program)			100.00%	100%
Other				
Program Enabled Savings			100.00%	100%

1 **Table 2: Allocation of 2012 Programs**

Program	Rate Allocations for LRAMVA			
	Res	GS<50	GS>50	Total
Consumer Program				
Appliance Retirement	100.00%			100%
HVAC Incentives	100.00%			100%
Conservation Instant Coupon Booklet	100.00%			100%
Residential Demand Response				0%
Business Program				
Retrofit		21%	79%	100%
Direct Install Lighting		100%		100%
New Construction			100.00%	100%
Energy Audit			100.00%	100%
Demand Response 3				0%
Industrial Program				
Energy Manager			100.00%	100%
Demand Response 3				0%
Home Assistance Program				
Home Assistance Program	100%			100%
Pre-2011 Programs completed in 2011				
High Performance New Construction			17.00%	17%
Other				
Program Enabled Savings			100.00%	100%

Table 3: Allocation of 2013 Programs

Program	Rate Allocations for LRAMVA			
	Res	GS<50	GS>50	Total
Consumer Program	kW	-37,635	-1,313	
Appliance Retirement	100.00%			100%
HVAC Incentives	100.00%			100%
Conservation Instant Coupon Booklet	100.00%			100%
Residential Demand Response				0%
Business Program				
Retrofit		5%	95%	100%
Direct Install Lighting		100%		100%
New Construction			100.00%	100%
Energy Audit			100%	100%
Business Refrigeration Local Program		85.00%	15.00%	100%
Demand Response 3				0%
Industrial Program				
Energy Manager			100.00%	100%
Demand Response 3				0%
Home Assistance Program				
Home Assistance Program	100%			100%
Pre-2011 Programs completed in 2011				
High Performance New Construction			17.00%	17%
Other				
Program Enabled Savings			100.00%	100%

Table 4: Allocation of 2014 Programs

Program	Rate Allocations for LRAMVA			
	Res	GS<50	GS>50	Total
Consumer Program	kW	-37,635	-1,313	
Appliance Retirement	100%			100%
HVAC Incentives	100%			100%
Conservation Instant Coupon Booklet	100%			100%
Residential Demand Response				0%
Residential New Construction	100.00%			100%
Business Program				
Retrofit		14%	86%	100%
Direct Install Lighting		100%		100%
Building Commissioning			100%	100%
New Construction			100.00%	100%
Energy Audit			100%	100%
Business Refrigeration Local Program		85.00%	15.00%	100%
Demand Response 3				0%
Industrial Program				
Energy Manager			100.00%	100%
Demand Response 3				0%
Home Assistance Program				
Home Assistance Program	100%			100%
Other				
Program Enabled Savings			100.00%	100%
Time of Use Savings				0%
LDC Pilots	100.00%			100%

Table 5: Allocation of 2015 Programs

Program	Rate Allocations for LRAMVA			
	Res	GS<50	GS>50	Total
Legacy Framework				
Residential Program				
Coupon Initiative	100.00%			100%
Bi-Annual Retailer Event Initiative	100.00%			100%
Appliance Retirement Initiative	100.00%			100%
HVAC Incentives Initaitive	100.00%			100%
Residential New Construction and Major Renovation Initiative	100.00%			100%
Commercial & Institutional Program				
Energy Audit Initiative			100.00%	100%
Efficiency: Equipment Replacement Incentive Initiative		14%	86%	100%
Direct Install Lighting and Water Heating Initiative		100%		100%
New Construction and Major Renovation Initiative			100.00%	100%
Industrial Program				
Process and Systems Upgrades Initiatives - Energy Manager Initiative			100.00%	100%
Low Income Program				
Low Income Initiative	100%			100%
Other				
Program Enabled Savings			100.00%	100%
Conservation Fund Pilots				
Conservation Fund Pilot - EnerNOC			100.00%	100%
Loblaws Pilot			100.00%	100%
Conservation First Framework				
Residential Province-Wide Programs				
Save on Energy Coupon Program	100%			100%
Save on Energy Heating and Cooling Program	100%			100%
Save on Energy New Construction Program	100.00%			100%
Non-Residential Province-Wide Programs				
Save on Energy Audit Funding Program			100.00%	100%
Save on Energy Retrofit Program		14%	86%	100%

b) Many programs are specific to a particular customer class, particularly programs aimed at Residential customers. There are a few programs such as energy retrofits where there is uptake by customers in different rate classes. Allocation was performed by the CDM department based on a study performed of the types of customers and savings amounts in the various programs. Based on their knowledge, the CDM department believes that these portions have remained relatively steady and that resulting allocations are reasonably accurate. Alectra is in the process of implementing CDM tracking and reporting of program results by customer and customer class for greater accuracy.

c) Please see (b) above.

PRZ-Staff-17

Reference(s): 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.**

Response:

a) Alectra Utilities' cannot confirm that savings adjustments were applied prospectively in the workform. Alectra Utilities' confirms that savings adjustments were applied back to the year of program implementation. For example, savings adjustment identified in 2013 for 2012 programs was applied in 2012, but instead of presenting it on a separate "True-up" line, the adjustment was added to the "Verified" line. Please refer to the exhibit below that demonstrates an application of savings adjustments.

Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)								
		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
HVAC Incentives	Verified	4,380,199	5,192,089	5,192,089	5,192,089	5,192,089	5,192,089	5,192,089	5,192,089	5,192,089	5,192,089
Adjustment to 2011 savings	True-up		-811,890	-811,890	-811,890	-811,890	-811,890	-811,890	-811,890	-811,890	-811,890
	Sum	**4,380,199**	4,380,199	4,380,199	4,380,199	4,380,199	4,380,199	4,380,199	4,380,199	4,380,199	4,380,199

Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)								
		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
HVAC Incentives	Verified	5,192,089	5,192,089	5,192,089	5,192,089	5,192,089	5,192,089	5,192,089	5,192,089	5,192,089	5,192,089
Adjustment to 2011 savings	True-up	-811,890	-811,890	-811,890	-811,890	-811,890	-811,890	-811,890	-811,890	-811,890	-811,890
	Sum	**4,380,199**	4,380,199	4,380,199	4,380,199	4,380,199	4,380,199	4,380,199	4,380,199	4,380,199	4,380,199

b) Alectra Utilities' revised the presentation of savings adjustments within each year, so to meet the Board's Staff expectations. In the revised workform, Alectra Utilities' presents true-up adjustments in the rows named "True-up". This revision does not affect the work form's calculations.

c) Alectra Utilities' cannot confirm that there were no adjustments to CDM savings in 2013, 2014, 2015. Alectra Utilities' adjusted 2013 results as per *IESO's 2011-2014 Final CDM*

Report. 2013 savings adjustments identified in 2014 for 2013 programs were applied in 2013 (refer to PRZ-Staff-17(a)).

2014 results are presented in accordance with the *IESO's 2011-2014 Final CDM Report*. "Table 2: Adjustments to PowerStream Inc. Net Verified Results due to Variances" of the above mentioned report does not have adjustments to 2014 net verified results.

For the purposes of this submission, Alectra adjusted 2015 results as per *IESO's Final 2015 Annual Verified Results Report for PowerStream* issued on June 30, 2016.

PRZ-Staff-18

Reference(s): 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.

Response:

Business Refrigeration program is similar to Small Business Lighting and Retrofit programs where measures are installed that provide savings for the entire operation period. I.e. Motors are installed that run 24 hours and thereby provide continuous savings.

PRZ-Staff-19

Reference(s): Tab 5 of LRAMVA Work Form (Attachment 28)

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

Response:

Alectra Utilities' populated Tab 7. Persistence Data of the LRAMVA Workform with the verified savings results from the IESO's (or former OPA's) persistence reports.

Projects completed in 2011 can have measures that provide savings for 15 years as a result, in 2025 we would still expect to see savings from the 2011 projects assuming the equipment has a lifespan of 15 years.

PRZ-Staff-20

Reference(s): 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.

Response:

Alectra Utilities' provides five reports used to support the LRAMVA calculation for the PowerStream RZ. PRZ-Staff-20_Attach 1 is the 2011-2014 Final Verified Report. PRZ-Staff-20_Attach 2 is the 2011-2014 Persistence Report. PRZ-Staff-20_Attach 3 is the 2015 Final Verified Report. PRZ-Staff-20_Attach 4 is the 2015 Persistence Report. PRZ-Staff-20_Attach 5 is the 2016 Final Verified Report.

PRZ-Staff-21

Reference(s): 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.

Response:

Alectra Utilities' has made changes to the PowerStream rate zone LRAMVA work form as a result of its responses to interrogatories. The LRAMVA work form has been updated to include the savings related to 2015 CDM programs from the IESO's recently published Final Verified 2016 Annual LDC CDM Program Results Report. Alectra Utilities' has also updated the LRAMVA work form to include LED street light savings. This is discussed in further detail below. An updated version of the LRAMVA work form is filed as PRZ-Staff-21_Attach 1_LRAMVA Work Form PowerStream RZ. The LRAMVA claim has been revised from $1,699,829 to $2,017,001 based on these updates.

LED Street Light Replacements:

The LRAMVA claim filed is based on the Annual CDM Savings reports issued by IESO. The CDM team takes the program amounts from the reports and provides the allocation to customer class for entry into the LRAMVA Work Form.

Municipalities in the PowerStream Rate Zone ("PRZ") started to replace existing street lights with LED in 2013 and these projects are scheduled to continue into 2020. The replacement LED street lights have a smaller kW load resulting in reductions in energy consumption and kW demand of up to 60%. Street lights are billed distribution charges based on the kW demand.

There are no kW demand savings for street light LED projects ("SL LED projects") reported by the IESO in their final reports as the reduction in demand does not fall into the peak kW demand savings as defined for CDM reporting to IESO . Accordingly no kW demand savings were allocated to the street light class.

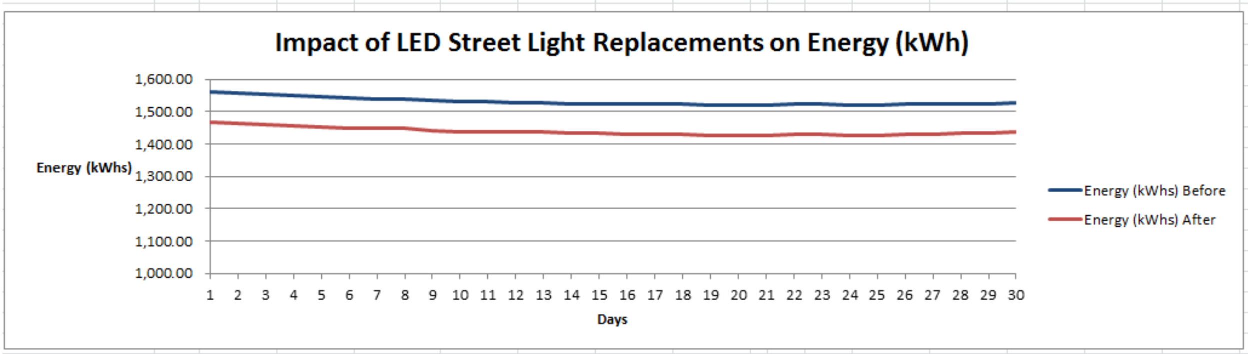
Although no kW demand savings are reported by the IESO for the SL LED projects, these projects reduce billed demand and resulted in lost revenue. The following discussion on street light billing by the PRZ is provided to assist with understanding the impact and its implications for the calculation of LRAMVA for this customer class.

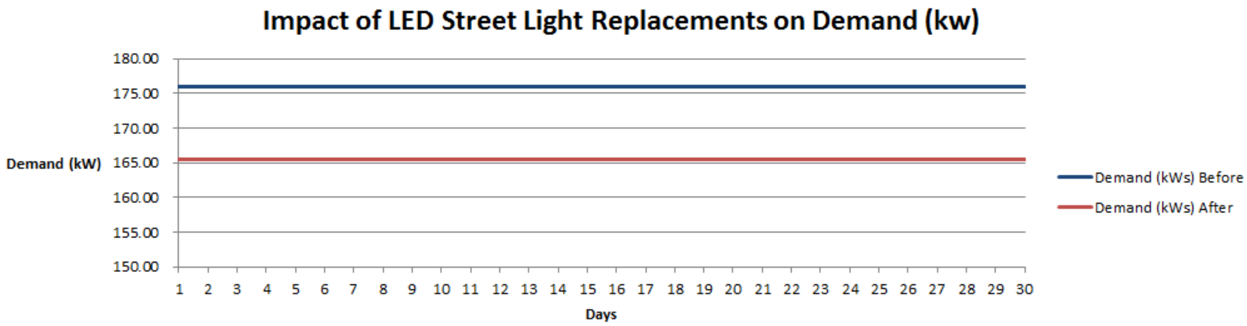
Street Lights are billed for the calendar month based on the OEB approved Street Light load profile. The Street Light profile specifies for each day of the year how many hours the streetlights are on. The energy consumed by street lights is calculated by multiplying the total street light load in kWs times the number of hours that the lights are on during the month to get the kWh energy consumption. As street lights are either on or off, the maximum kW demand for the month will be equal to the total kW load of the street lights when they are on.

The impact of the LED street lights on the energy used and the billable demand is illustrated by the following example:

- a street light customer has 1,000 street lights with a total kW load of 176 kWs
- the customer replaces 100 lights with a load of 17.6 kW with LED lights with a load of 7.0 kW
- total load after the LED replacements is 176.0-17.6+7.0 = 165.4 kW
- the street light profile indicates that there are 268 lighting hours in the month

The following charts illustrate the reduction in billing of kWh energy and demand charges for this customer as a result of the LED Street Light replacements.





The SL LED projects have reduced the kWs billed for the street lighting class. SL LED projects started in the fall of 2013 however the impacts of the reduction in billed kWs from SL LED projects has not been included in the LRAMVA amounts. The LRAMVA for the Street Lighting class needs to be updated to reflect the actual savings realized by from these retrofit projects.

Rates for the years 2013 to 2016 are underpinned by PowerStream's 2013 cost of service rates (EB-2012-0161). In setting its 2013 rates, an adjustment was made to its load forecast for the estimated impact of planned CDM activities. Planned CDM activity was by program and the uptake by rate class was not known nor forecasted. The CDM adjustment was applied to the total load and the net load was then allocated to the rate classes including the street lighting class.

As LED streetlights are installed, reports are received from the municipalities with the details of the existing street lights and load that have been removed and the replacement LED street lights installed and their load ("LED Reports"). Billing uses the LED Reports to update the monthly billing of street lights. The first billing adjustment for LED street light installation was made in 2014. PowerStream has used the reduction in billed kW demand from the LED Reports for purposes of calculating the LRAMVA adjustment in respect of the SL LED projects.

From 2013 to 2015, 22,537 street lights with a total load of 4,156 kWs have been replaced with LED street lights with a load of 1,575 kWs, for a reduction in street light billed load of 2,581 kWs. This has resulted in lost revenue as summarized in the table below.

1 **Table 1: LRAMVA Adjustment for LED street light installations**

	2014	2015	Total
LED Replacements in year	8,856	13,681	22,537
Reduction in kW demand	875	1,707	2,581
Reduction in billed kW	6,969	17,099	24,068
Revenue Reduction	$ 45,782	$ 113,786	$ 159,569
Carrying Charges	$ 212	$ 979	$ 1,191
Adjustment to Street Lighting LRAMVA	**$ 45,994**	**$ 114,765**	**$ 160,759**

2

PRZ-Staff-22

Reference(s): 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)**

Response:

A comprehensive review of activity in each of the disposition years resulted in a redistribution adjustment between principal and interest. See Table 1 and corresponding notes below.

Table 1: Summary of Adjustments to Account 1595

Year	Principal Adjustments [1)	Interest Adjustments [2]	Net total	Notes
2009	$ -	$ (21,764)	$ (21,764)	5
2010	$ 7,318	$ 153	$ 7,471	3,5
2011	$ 135,000	$ 41,188	$ 176,188	3,5
2012	$ (142,316)	$ (5,332)	$ (147,648)	3,5
2013			$ -	
2014	$ (79,150)	$ 64,903	$ (14,247)	4,5
Total	$ (79,148)	$ 79,148	$ -	

1. Please see Exhibit 3, Tab 1, Schedule 1, Attachment 26 -IRM model _PowerStream RZ_ tab 3. Continuity Schedule, column BP.

2. Please see Exhibit 3, Tab 1, Schedule 1, Attachment 26 -IRM model _PowerStream RZ_ tab 3. Continuity Schedule, column BU.

3. Refund billings were applied in error to 2012 year but should have been applied to 2010 and 2011.

4. The Accounting Procedures Handbook, Frequently Asked Question 6, outlines the sequence of how rate rider billings are to be applied to Board approved disposition

recovery/refund amounts. For the 2014 disposition year there was an over application of billings to principal. The 2014 principal balance should be zero and therefore the incremental billings needed to be applied to the board approved interest.

5. Accounting for carrying charge interest was misapplied within several of the disposition years. Adjustments were required to redistribute carrying charge to the appropriate disposition year.

PRZ-Staff-23

Reference(s): 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?**

Response:

a) The 2016 approved Class B Non-RPP GA rate rider is based on an allocation of the Class B non-RPP variance across both the interval metered and non-interval metered Class B non-RPP customers. As provided in the Application, none of the variance is attributable to the interval metered customers. Alectra Utilities' PowerStream Rate Zone (PRZ) proposes a correction to the GA rate rider for these customers at the earliest opportunity, which would be January 1, 2018.

b) As described in part (a) above, this factor was not taken into account and the GA variance was allocated across all Class B non-RPP customers in error.

c) Yes. Alectra Utilities' is proposing two separate tariffs, one to refund the over collection from the interval metered Class B non-RPP customers and a corrected one to collect the remaining amount, including a refund to the interval metered customer, from the non-interval metered customers.

d) The GA variance should not have been allocated to interval metered customers in 2016 rates.

i. Alectra Utilities' identified this issue while documenting the settlement procedures in the PowerStream RZ for this Application.

ii. Alectra Utilities' has identified this error in Alectra Utilities' 2018 Electricity Distribution Rate Application and has proposed a solution to address the error in the evidence provided at Exhibit 2, Tab 3, Schedule 5, p.6.

PRZ-Staff-24

Reference(s): 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.

a) Has Alectra PowerStream 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.

b) Please provide evidence regarding the 9 customers who transitioned to Class A in 2015 with respect to their billing adjustments for 2015 consumption.

c) Please calculate billing adjustments for the customers who transitioned from Class B to A in 2015 as well as in 2016.

d) Please correct and refile the rate rider calculations as necessary.

Response:

a) Alectra Utilities' has corrected the CBR rate rider calculations for the PowerStream RZ to include 2015 transitioned customers and April 1, 2015 to December 31, 2016 consumption kWh. The revised rate rider calculations are presented in Tab "6.2a CBR-B allocation" of the Board's 2018 IRM Rate Generator Model. The updated IRM Rate Generator Model is filed in response to G-Staff-1.

b) There were 9 new Class A customers in July 2015. Their respective 2015 and 2016 consumption and load figures are presented in Tab "6. Class A Consumption Data" of the Board's 2018 IRM Rate Generator Model. Table 1 below summarizes the adjustment for 2015 consumption.

Table 1: Adjustment to 2015 Consumption (CBR Rate Rider)

	Full 2015	**Jan-Mar 2015**	**Apr-Dec 2015**
Total Metered kWh	8,605,762,844	2,374,512,526	6,231,250,317
WMP	30,566,606	7,272,956	23,293,650
	8,575,196,237	2,367,239,570	6,207,956,667
LESS: Class A (were Class A full year)	110,569,203	35,402,015	75,167,188
LESS: Class A (ONLY Class A volumes for Transition customers)	111,281,639	8,320,985	102,960,654
	8,353,345,395	**2,323,516,570**	**6,029,828,825**

c) Billing adjustments for the customers who transitioned from Class B to A in 2015 as well as in 2016 are calculated on Tab 6.2a CBR_B Allocation of the Board's 2018 IRM Rate Generator Model.

d) CBR Class B rate rider calculations are revised and submitted as part of the Board's 2018 Rate Generator Model (Tab "6.2 CBR B"). An updated Rate Generator Model is filed with G-Staff-2.

PRZ-Staff-25

Reference(s): 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.

Response:

Alectra Utilities' confirms that the amount to be disposed of by rate riders is ($25,558,512) as provided in Exhibit 2, Tab 3, Schedule 5, Table 81 – Group 1 Disposition by Customer Group – PowerStream RZ. The amount of ($26,300,803) was stated in error.

PRZ-Staff-26

Reference(s): 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.

Response:

1) PRZ uses an approach which is very similar to that described in 1(a) above. PRZ books both Charge Type 1142 (formerly 142), and Charge Type 148 from the IESO invoice into the cost of power account 4705. The actual cost per kWh from charge type 148, Class B Global Adjustment Settlement Amount, is then applied to the Class B non-RPP kWhs for the month to calculate the Class B non-RPP GA cost. An entry is made to reduce account 4705 and charge account 4707, Global Adjustment non-RPP, for the Class B non-RPP GA cost. The Class B non-RPP GA billing are then compared to the Class B non-RPP GA cost in account 4707 and the variance is recorded in account 1589.

2)

a) At December 31, 2016, the non-RPP GA costs were based on the IESO invoice for December 2016 received in January 2017. Revenues were based on actual billings for GA with an unbilled accrual as at December 31, 2016. The resulting variance in account 1589 is the difference between the non-RPP GA revenue and cost.

b) Please see Alectra Utilities response to G-Staff-1.

3)

a) At December 31, 2016, the variances recorded in account 1588 were derived from the associated revenues and costs for energy as described below.

Energy revenues for the month are based on the actual billings in the month less the unbilled accrual from the prior month plus the month-end unbilled accrual.

Energy costs are based on the actual IESO invoices for charge types ("CT") 101, 148 and 1142 less the re-allocation of non-RPP GA cost as described above in parts (1) and (2). The costs booked at December 31, 2016 were based on the IESO invoice for

December 2016. As previous month's accrued costs had been reversed and replaced with actual invoice costs, costs for the entire year were based on actuals.

Estimates are used to calculate the settlement amount for CT 1142 within 5 business days of month end to allow time for IESO to process and include the adjustment in the invoice issued in the following month. The amounts used to calculate the CT 1142 are updated to actual three months later and the difference between the actual and estimate ("RPP settlement true-up") is included in the current month settlement.

b) PRZ has proposed adjustments to account 1588 in the DVA continuity schedule relating to subsequent adjustments related to 2016 as per the OEB's letter on the *"Guidance on the Disposition of Accounts 1588 and 1589"* dated May 23, 2017.

PRZ included an adjustment of $811,309 to Account 1588 in the DVA Continuity Schedule for the impact of RPP settlement true up related to 2016. This adjustment was entirely related to item iv. RPP Settlement (Charge Type 1142). There were no adjustments related to items i, ii, and iii. A summary of the adjustment is presented in the table below.

Table X: 2017 RPP Settlement True-ups related to 2016

Month	**Amount**	**True-up Month**	**Impact on IESO Invoice**
Jan-17	($1,504,917.59)	Oct-16	Payment to IESO
Feb-17	($614,663.47)	Nov-16	Payment to IESO
Mar-17	$2,930,890.41	Dec-16	Payment from IESO
Total	**$811,309.35**		Payment from IESO

The RPP Settlement true up amount as shown in the table above was the difference between the actual RPP Settlement of a trading month and the estimate RPP Settlement that originally submitted to the IESO for the same trading month.

Please refer to PRZ-Staff-26_Attach 1_RPP true-up PowerStream RZ for details of the estimated and actual RPP Settlement amounts and resulting RPP settlement true-ups for October, November and December 2016.

Use trading month October 2016 as an example. The estimated RPP Settlement amount for October 2016 was $5,938,011 payment from the IESO, the actual RPP Settlement amount for October 2016 was $4,433,093 payment from the IESO, resulting in an overpayment from the IESO of $1,504,918 for the trading month of October 2016, which was refunded to the IESO during the January 2017 settlement process.

PRZ estimated the October 2016 RPP Settlement amount at end of the month. The estimated RPP Settlement amount of $5,938,011 (payment from the IESO) was the difference between estimate RPP revenue of $43,657,743 and associated true cost of power of $49,595,754, which were both based on estimate consumption of RPP consumers, applied with the OEB approved RPP rates for revenue and commodity market price and second estimate Global Adjustment rate for cost, respectively.

PRZ calculated the actual October 2016 RPP Settlement amount at end of January 2017 using actual customer bills that billed for the period. The actual RPP settlement amount of $4,433,093 (payment from the IESO) was the difference between actual RPP revenue of $33,790,663, which was the production of actual consumption and RPP price, and commodity and Global Adjustment costs of $38,223,756 based on the actual consumption, a weighted average commodity price and actual Global Adjustment rate.

Subsequently, PRZ determined the October 2016 RPP settlement true up amount by comparing the actual RPP Settlement amount and the estimate RPP Settlement amount for the same period.

c) The debit adjustment of $811,309 shown in the column “Principal Adjustments During 2016” for Account 1588 is for the adjustments to the 2016 estimates made during 2017 as discussed in part 3(b) above.

PRZ-Staff-26: Details of 2017 RPP Settlement Amount True-ups re 2016

Oct-16 Estimate

TOU TIER	NUM OF CUSTOMERS	ESTIMATED KWH	ESTIMATED RPP AMOUNT	ESTIMATED TCOP AMOUNT	ESTIMATED GA AMOUNT	VARIANCE
Tier 1	20,544	22,523,950	2,319,985	269,723	2,653,330	603,068
Tier 2	-	36,624,294	4,431,540	438,575	4,314,343	321,378
On-peak	-	66,877,953	12,038,031	800,861	7,878,224	- 3,358,947
Mid-peak	-	57,420,380	7,579,488	687,607	6,764,121	- 127,761
Off-peak	324,379	198,720,712	17,288,699	2,379,673	23,409,299	8,500,273
Total	344,923	382,167,290	43,657,743	4,576,439	45,019,315	5,938,011

IESO owes us

Actual

TOU TIER	Actual NUM OF CUSTOMERS	Actual KWH	Actual RPP AMOUNT	Actual TCOP AMOUNT	Actual GA AMOUNT	Actual VARIANCE
Tier 1	21,590	22,543,637	2,322,005	294,912	2,530,749	503,655
Tier 2	-	31,102,185	3,763,361	409,926	3,491,531	138,096
On-peak	-	46,501,917	8,370,072	724,743	5,220,305	- 2,425,024
Mid-peak	-	43,720,684	5,771,083	683,030	4,908,081	- 179,972
Off-peak	326,937	155,910,908	13,564,142	2,457,925	17,502,555	6,396,338
Total	348,527	299,779,331	33,790,663	4,570,536	33,653,220	4,433,093

IESO owes us

Ture-up Jan-17

TOU TIER	TRUE UP NUM OF CUSTOMERS	TRUE UP KWH	TRUE UP RPP AMOUNT	TRUE UP TCOP AMOUNT	TRUE UP GA AMOUNT	TRUE UP VARIANCE
Tier 1	1,046	19,687	2,020	25,188	- 122,581	- 99,413
Tier 2	-	- 5,522,109	- 668,178	- 28,649	- 822,811	- 183,282
On-peak	-	- 20,376,036	- 3,667,959	- 76,118	- 2,657,919	933,922
Mid-peak	-	- 13,699,696	- 1,808,406	- 4,577	- 1,856,040	- 52,211
Off-peak	2,558	- 42,809,805	- 3,724,557	78,252	- 5,906,744	- 2,103,934
Total	3,604	- 82,387,959	- 9,867,081	- 5,903	- 11,366,095	- 1,504,918

Nov-16 Estimate

TOU TIER	NUM OF CUSTOMERS	ESTIMATED KWH	ESTIMATED RPP AMOUNT	ESTIMATED TCOP AMOUNT	ESTIMATED GA AMOUNT	VARIANCE
Tier 1	20,597	25,216,396	2,597,310	394,962	2,899,915	697,566
Tier 2	-	26,945,092	3,260,356	422,038	3,098,686	260,368
On-peak	-	47,277,856	8,510,013	740,508	5,436,953	- 2,332,553
Mid-peak	-	45,780,698	6,043,053	717,058	5,264,780	- 61,215
Off-peak	324,933	158,457,249	13,785,781	2,481,898	18,222,584	6,918,700
Total	345,530	303,677,292	34,196,514	4,756,463	34,922,918	5,482,866

IESO owes us

Actual

TOU TIER	Actual NUM OF CUSTOMERS	Actual KWH	Actual RPP AMOUNT	Actual TCOP AMOUNT	Actual GA AMOUNT	Actual VARIANCE
Tier 1	22,005	25,130,576	2,586,850	424,803	2,791,747	629,700
Tier 2	-	28,551,900	3,454,630	504,167	3,171,831	221,368
On-peak	-	44,139,485	7,934,294	777,738	4,903,455	- 2,253,101
Mid-peak	-	42,616,604	5,618,334	747,769	4,734,280	- 136,285
Off-peak	327,756	153,124,000	13,301,404	2,697,380	17,010,546	6,406,521
Total	349,761	293,562,564	32,895,514	5,151,858	32,611,859	4,868,203

IESO owes us

Ture-up Feb-17

TOU TIER	TRUE UP NUM OF CUSTOMERS	TRUE UP KWH	TRUE UP RPP AMOUNT	TRUE UP TCOP AMOUNT	TRUE UP GA AMOUNT	TRUE UP VARIANCE
Tier 1	1,408	- 85,820	- 10,460	29,842	- 108,168	- 67,866
Tier 2	-	1,606,808	194,274	82,129	73,145	- 39,000
On-peak	-	- 3,138,371	- 575,719	37,230	- 533,498	79,452
Mid-peak	-	- 3,164,095	- 424,719	30,711	- 530,501	- 75,070
Off-peak	2,823	- 5,333,249	- 484,377	215,482	- 1,212,038	- 512,179
Total	4,231	- 10,114,727	- 1,301,001	395,395	- 2,311,059	- 614,663

Dec-16 Estimate

TOU TIER	NUM OF CUSTOMERS	ESTIMATED KWH	ESTIMATED RPP AMOUNT	ESTIMATED TCOP AMOUNT	ESTIMATED GA AMOUNT	VARIANCE
Tier 1	20,332	26,008,778	2,678,920	521,637	2,047,428	- 109,855
Tier 2	-	31,059,486	3,758,198	622,935	2,445,002	- 690,261
On-peak	-	44,541,927	8,017,548	893,342	3,506,339	- 3,617,867
Mid-peak	-	44,965,879	5,935,498	901,845	3,539,712	- 1,493,941
Off-peak	326,200	154,320,934	13,425,921	3,095,091	12,148,141	1,817,311
Total	346,532	300,897,004	33,816,086	6,034,850	23,686,623	- 4,094,613

We owe IESO

Actual

TOU TIER	Actual NUM OF CUSTOMERS	Actual KWH	Actual RPP AMOUNT	Actual TCOP AMOUNT	Actual GA AMOUNT	Actual VARIANCE
Tier 1	21,489	27,892,367	2,872,931	581,958	2,428,869	137,896
Tier 2	-	31,726,623	3,838,922	670,545	2,762,754	- 405,623
On-peak	-	47,699,334	8,585,852	981,946	4,153,661	- 3,450,245
Mid-peak	-	45,102,682	5,953,515	930,689	3,927,542	- 1,095,284
Off-peak	329,022	176,999,834	15,398,946	3,635,334	15,413,147	3,649,534
Total	350,511	329,420,839	36,650,167	6,800,471	28,685,973	- 1,163,723

We owe IESO

Ture-up Mar-17

TOU TIER	TRUE UP NUM OF CUSTOMERS	TRUE UP KWH	TRUE UP RPP AMOUNT	TRUE UP TCOP AMOUNT	TRUE UP GA AMOUNT	TRUE UP VARIANCE
Tier 1	1,157	1,883,589	194,010	60,321	381,441	247,751
Tier 2	-	667,136	80,724	47,610	317,752	284,637
On-peak	-	3,157,407	568,304	88,604	647,322	167,622
Mid-peak	-	136,803	18,017	28,845	387,830	398,657
Off-peak	2,822	22,678,900	1,973,025	540,242	3,265,006	1,832,223
Total	3,979	28,523,835	2,834,081	765,621	4,999,350	2,930,890

PRZ-Staff-27

Reference(s): 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?

Response:

a) Alectra Utilities' has had ongoing communication with Metrolinx, with respect to this project. Alectra Utilities' awaits Metrolinx's further information and details regarding the timing and location of the necessary construction. Once Alectra Utilities' has this information, it can then proceed to revise the business plan for this project to match Metrolinx's proposed crossings.

b) Alectra Utilities' anticipates that it will be required to perform capital work in connection with the Metrolinx Crossings Remediation Project ("Metrolinx Project") in the PRZ in 2018. The amounts will be material and incremental to the amounts filed in the 2018 Incremental Capital Module ("ICM") Application.

Alectra Utilities’ is required to make these changes to its distribution system to accommodate the Metrolinx Project and is unable to recover these costs from Metrolinx.

The government initiative to electrify the GO train system on the major routes is an event that is outside of Alectra Utilities’ control. This is not within the normal course of business and it should not impact its distribution system plan and the necessary work required to supply customers and maintain the distribution system. This is an expenditure that a number of distributors will face. It is for this reason that Alectra Utilities’ considers separate treatment necessary – on the basis of the unknown timing and magnitude of the investment.

Alectra Utilities’ proposes to file for funding adders for the Metrolinx Project in its 2019 rate application. As indicated in the response to (a) above, the necessary information should be available then to support the setting of funding adders starting in 2019.

Once the Metrolinx Project related work is completed and the actual costs are known, Alectra Utilities will file an application for disposition of these costs, either as part of an annual rate application or as a separate stand-alone application. Please see Alectra Utilities’ response to part c), below.

c) See Alectra Utilities’ response to part b), above. Alectra Utilities’ wishes to revise the accounting orders for the PRZ and the ERZ to revise the following paragraph:

Alectra Utilities’ proposes to apply to the OEB for any cost recovery of amounts recorded in the OEB-approved deferral account during the 2019 Annual Filing.

To:

Alectra Utilities’ proposes to apply to the OEB for funding adders related to the projected cost amounts during the 2019 rate application or subsequent applications. Upon completion of the work related to the Metrolinx Project, Alectra Utilities’ proposes to seek recovery of these costs recorded in the OEB-approved deferral account through rate riders that would remain in place until the next rebasing, when the assets would then become part of rate base.

i. Alectra Utilities’ proposes that the disposition of the Metrolinx-related costs in Account 1508 would result in disposition rate riders to recover the annual cost related to the capital until rebasing and temporary rate riders to recover the annual costs for periods prior to the disposition rate riders.

ii. Alectra Utilities' observes that the OEB has disposed of other Group 2 deferral and variance accounts, as part of a Price Cap IR proceeding or as separate applications outside of a rebasing in the past. Recent examples of this include:

- 1521 Special Purpose Charge Assessment Variance Account
- 1555 Smart Meter Capital and Recovery Offset Variance Account
- 1556 Smart Meter OM&A Variance Account
- 1562 Deferred Payments In Lieu of Taxes
- 1563 Contra Asset - Deferred Payments In Lieu of Taxes
- 1568 LRAM Variance Account
- 1592 PILs and Tax Variances for 2006 and Subsequent Years, Sub-account HST/ OVAT Input Tax Credits (ITCs)

Alectra Utilities' believes that it is appropriate that these costs be reviewed and disposed of on a current basis.

iii. Alectra Utilities' does not propose to update its rate base in the 2019 Price Cap IR application; it proposes to apply for funding adders for the Metrolinx related capital expenditures. Once the project is complete, Alectra Utilities' proposes to apply for disposition rate riders as described in part c) (i.), above.