Responses to Vulnerable Energy Consumers Coalition Interrogatories

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1.0-VECC-1

Reference: All

a) Please explain what incentives, benchmarks or other efficiency metrics are used to encourage cost reductions during the proposed rate period.

b) Please explain Horizon's proposal if it over earns during the rate period.

c) Please provide Horizon's annual reporting proposal during the rate period.

Response:

a) Please see Horizon Utilities' response to 1-Staff-4.

b) In its discussion of off-ramps to the rate plan in Exhibit 1, Tab 12, Schedule 3 of the Application, Horizon Utilities has identified that it would be subject to the Board's review, should its earnings be ±300 basis points relative to the Board's regulated rate of return. In that event, Horizon Utilities expects that it may be subject to both a regulatory review and the potential termination of the rate plan, as described in the Board's RRFE Report.

c) Horizon Utilities expects to continue to provide annual reporting to the OEB through the RRR filings to which all electricity distributors are subject. The RRFE Report also contemplates that the Board may specify further reporting on capital expenditures, but such a determination has not been made by the Board to Horizon Utilities' knowledge. Horizon Utilities does not propose any additional reporting in the Application.

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1.0-VECC-2

Reference: E1/T12/S4

a) Are any costs included in this application for the elimination of long-term load transfers? If so please provide these.

b) What precludes Horizon Utilities from eliminating all or some of its load transfers through mutually agreed to service area amendments?

Response:

a) Horizon Utilities has not included any costs in this application for the elimination of long-term load transfers.

b) Horizon Utilities does not have an issue with eliminating its long-term load transfers through mutually agreed upon service area amendments so long as it is in the best interest of customers. Horizon Utilities has not included any costs in this application for the elimination of the long-term load transfers, as identified in a) above. Horizon Utilities would expect that such costs would be recoverable through rates; this could be dealt with through an annual adjustment.

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1.0-VECC-3

Reference: E1

a) Please explain how this application differs from a 5 year cost of service plan.

Response:

a) Please see Horizon Utilities' response to BOMA-7c), 1-EP-1, and SEC-1.

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1.0-VECC-4

Reference: E1

a) Please explain how variations in capital spending/rate base from proposed are to be addressed during the five year period of the plan. What is the consequence if Horizon significantly under or over spends on projected projects or spends on different projects than anticipated?

Response:

a) Please see Horizon Utilities' response to 1-Staff-3 b).

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2.0-VECC-5

Reference: E2/T1/S2

a) Please provide the salvage value of disposed assets for 2010, 2011, 2012 and 2013.

Response:

a) The proceeds from disposed assets (salvage value) are as follows: 2010 - $112,609; 2011 - $45,624; 2012 -$433,492; 2013 - $518,695.

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2.0-VECC-6

Reference: E2/T4/Appendix 2-3 Lead/Lag Study

a) Please provide the billing cycle for each customer class.

b) Please show the calculation of the service lag, by providing a table which shows for all customer class the number of customers, customer weighting, frequency of meter read, service mid-point and the resulting service lag.

c) Did Navigant sample Horizon's database to determine the billing lag? If yes please explain the size and type of sample, sample month etc. If not please explain why not.

d) Other studies have shown a payment processing lag of between 1 and 1.1 days (Ottawa Hydro, Verdian). Please provide the derivation of 1.54 days for the payment processing lag.

Response:

Subsequent to the submission of its Application, Horizon Utilities reviewed the inputs used to calculate the Revenue Lag of 27.06. It determined that some of the revenue allocations between monthly and bi-monthly billing were incorrect. Navigant Consulting Inc. recalculates the Revenue Lag to be 25.02 days, based on the correct revenue allocations. The revised Revenue Lag of 25.02 has been used to calculate a revised Working Capital Allowance. This revision results in a reduction in the Working Capital Allowance of 0.7% from 12.7% to 12.0%. Horizon Utilities has included a revised Lead/Lag Report from Navigant as an attachment to its response to 2-Staff-23a.

a) Horizon Utilities has a mix of bi-monthly and monthly billing cycles. The table below identifies the breakdown of billing cycles by rate class.

Customer billing cycles by class	
Residential	Monthly, Bi-monthly
GS < 50 kW	Monthly, Bi-monthly
GS > 50 kW to 4999 kW	Monthly
Large Use	Monthly
Sentinenel Lights	Monthly, Bi-monthly
Street Lighting	Monthly
Unmetered and Scattered	Monthly, Bi-monthly

b) Please see Horizon Utilities' response to Interrogatory 2-Staff-23a). Horizon Utilities has not provided the number of customers and customer weighting as these are not applicable. Horizon Utilities used revenue weighting to estimate the service lag not customer weighting. The customer weighting approach drew significant scrutiny in Horizon Utilities' 2011 CoS Application (EB-2010-0131). Board staff, in its submission stated that "that customer weighting overestimates the average service lag, and that revenue weighting for the service lag, as for other revenue and expense leads and lags, is appropriate"

c) Navigant Consulting Inc. sampled Horizon Utilities' data base to extract all bills issued for a particular day. A two month sample was used (January and February 2013) which comprised 41 business days. The billing lag was calculated as the difference between the date the bill was received by the customer and the meter reading date. Please also refer to Horizon Utilities' response to Interrogatory 2-EP-10b).

d) Please see Horizon Utilities' response to Interrogatory 2-EP-10f).

2.0-VECC-7

Reference: E2/T5/S1/pg.4 & E9/T7/S1

a) Please provide the rate riders and total amount collected on the assumption that Horizon removed the net value of stranded meters from rate base in 2015 and collected the costs over 3 years.

b) Horizon refers to G-2008-0002 as guidance for leaving stranded meters in rate base, however G-2011-0001, which supersedes that report states in part:

Consequently, starting in the 2012 EDR process, distributors seeking recovery of stranded meter costs should bring forward these requests in a cost of service application. It is preferable for the Board to review concurrently a distributor's smart meter and stranded meter costs in the same application where all the required adjustments to the rate base and the revenue requirement are reflected in rates at the same time. Requests for the recovery of stranded meter costs should be in accordance with the guidance provided in this section of the guideline and the cost of service filing requirements previously issued by the Board. Also, the stranded meter costs should be removed from any Cost Allocation run. (Guideline G-2011-0001 pages 21-22)

c) This suggests that stranded meters should be removed from rate base at the time a utility applies for rebasing. Has Horizon considered these Guidelines and has it removed the stranded meters from its cost allocation run?

Response:

a) The revenue requirement impacts identified by Horizon Utilities in Table 2-43 on page 5 of Exhibit 2, Tab 5, Schedule 1 calculated the revenue requirement impact of leaving the stranded meters in rate base using a short term debt cost rate of 2.46% for the deemed component of short-term debt supporting the stranded meter component of rate base. Horizon Utilities provides a revised Table 2-43 below which calculates the revenue requirement impact of leaving the stranded meters in rate base but with a revised short - term debt cost rate of 2.11% as updated in the Ontario Energy Board's letter: Cost of Capital Parameters for 2014 Cost of Service Applications, dated November 25, 2013. The responses below are based on this revised Table 2-43.

Revised Table 2-43

Description	2015	2016	2017	2018	2019	Total 2015-2019	2020	2021	2022	Total 2015-2022
Revenue Requirement with Stranded Meters in Rate Base	$1,529,293	$1,458,298	$1,387,302	$1,320,420	$1,251,044	$6,946,356	$1,178,409	$1,105,775	$1,033,141	$10,263,682
Revenue Requirement with NBV recovered over 5 year IR term	$2,106,089	$1,992,495	$1,878,902	$1,767,503	$1,653,025	$9,398,014	$0	$0	$0	$9,398,014
Difference	($576,795)	($534,198)	($491,600)	($447,082)	($401,982)	($2,451,658)	$1,178,409	$1,105,775	$1,033,141	$865,668

a) Horizon Utilities has provided the rate riders and total amount collected in the table below on the assumption that the net book value of stranded meters is removed from rate base in 2015 and the costs plus a rate of return is recovered from customers over three years. Horizon Utilities includes a regulated rate of return component to determine the amount to be recovered from customers. The implementation of Smart Meters was a public policy change mandated by the Ministry of Energy and as such Horizon Utilities was obligated to replace conventional meters with Smart Meters for all Residential and GS<50kW customers. Please also refer to the response to 2-Staff-22a).

Table 1: Rate Rider Including Return

Customer Class	# of Active Metered Customers (average 2015)	NBV of Stranded Meters including Rate of Return	Monthly Charge	Charge per Year
Residential	220,565	$6,797,247	$0.86	$2,265,749
GS< 50kW	18,428	$1,727,905	$2.60	$575,968
GS>50kW	2,198	$301,390	$3.81	$100,463
Total	**241,190**	**$8,826,541**		**$2,942,180**

b) A question has not been asked in part b) and therefore Horizon Utilities has not provided a response.

c) Horizon Utilities has considered Guideline G-2011-0001 as stated on lines 6-12 of page 3 of Exhibit 2, Tab 5 Schedule 1. Horizon Utilities also considered Section 2.5.1.4 of the Chapter 2 Filing Requirements, on lines 13-17 of page 3 of Exhibit 2, Tab 5 Schedule 1, which provides for the possibility of a different approach from that set out in Guideline G-2011-0001.

Horizon Utilities has not removed the stranded meters from the cost allocation run submitted in its Application.

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2.0-VECC-8

Reference: E2/T6/S1

a) Please provide a table showing the SAIDI and SAIFI indices related to each of:

a. 4kV/8kV plant failure

b. Underground XPLE Cable failure

Response:

a. The table below identifies the SAIDI and SAIFI due to material and equipment failures related to the 4kV and 8kV distribution system.

Table 1: 4kV/8kV Plant Failure SAIDI and SAIFI

		2010	2011	2012	2013
4kV & 8kV Distribution System	SAIDI	0.20	0.28	0.20	0.28
	SAIFI	0.14	0.26	0.16	0.15

SAIDI and SAIFI in the table above reflect the SAIDI and SAIFI of the 4kV and 8kV distribution system. SAIDI was calculated using the total customer minutes of outage and total customers serviced by the 4kV and 8kV distribution system. SAIFI was calculated using the total customers serviced by the 4kV and 8kV distribution system and the total number of customer interruptions experienced by customers serviced by the 4kV and 8kV distribution system.

b. The table below identifies the SAIDI and SAIFI due to failures of underground XLPE primary cable and accessories.

Table 2: Underground XPLE Cable Failure SAIDI and SAIFI

		2010	2011	2012	2013
XLPE Primary and Accessories	SAIDI	0.17	0.25	0.13	0.13
	SAIFI	0.15	0.12	0.13	0.09

SAIDI and SAIFI in the table above identify the contribution to Horizon Utilities' total system SAIDI and SAIFI resulting from outages caused by failures of XLPE primary cable and accessories. SAIDI was calculated using the total customer minutes of outage caused by failures of XLPE primary cable and accessories and Horizon Utilities' total customer count. SAIFI in the table above was calculated using the total number of customer interruptions due to failures of XLPE primary cable and accessories and Horizon Utilities' total customer count. Horizon Utilities cannot isolate the number of customers on a feeder that are serviced solely from primary XLPE cable and as such the reliability metrics calculation for XLPE by feeder uses total customer count.

2.0-VECC-9

Reference: E2

a) Please provide a breakdown of the service reliability performance metrics into the different category of reasons for the outage (excluding supply loss Code 2 outages). The table below provides an example format.

Description	2010 Totals	2011 Totals	2012 Totals	2013 Totals
Scheduled				
Supply Loss				
Tree Contact				
Lightning				
Def. Equip.(other than				
Pole Failure				
Weather				
Animals, Vehicle				
Unknown				
Total				

Response:

1 a) Please refer to Horizon Utilities' response to interrogatory 2-SIA-13 part a).

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2.0-VECC-10

Reference: E2/T6/S3

a) For the years 2014 – 2015 Please provide the details of the forecast customer connections shown in Table 2-72 in the format of Table 2-73 and which shows the average cost of connection for each rate class.

b) Please provide the average cost of connection for each rate class shown in Table 2-73

Response:

a) The table below provides the forecasted number of customer connections for the years 2014 - 2015, as well as the average cost of connection for each rate class. The project costs are net of capital contributions, as identified in Table 2-72 in Exhibit 2, Tab 6, Schedule 3, page 19. The average net project costs for Services over 300kW are higher in 2014 than 2015 due to known projects in 2014 with higher net expansion costs.

Table 1: Customer Connections 2014 - 2015

	2014		2015	
	Projects	Average Cost	Projects	Average Cost
Services Residential	78	$6,000	80	$6,060
Services <=300kW - >50kW	70	$13,000	72	$13,130
Services over 300kW	58	$33,800	60	$25,300
Services <=50kW	51	$5,300	52	$5,353
Embedded Generation	20	$0	20	$0
Other Customer Requests	9	$31,000	9	$31,310
Services Customer Owned Sub-Station	7	$25,000	7	$25,250
Total	**293**		**300**	

b) The table below identifies the average cost of connection for each rate class for the data listed in Table 2-73 in Exhibit 2, Tab 6, Schedule 3, page 20. The project costs are net of capital contributions, as identified in Table 2-72 in Exhibit 2, Tab 6, Schedule 3, page 19. The historical year over year average net project costs reflect the variability of project work scope and expansion charges.

Table 2: Customer Connections 2010 - 2013

	2010		2011		2012		2013	
	Projects	Average Cost	Projects	Average Cost	Projects	Average Cost	Projects	Average Cost
Services Residential	31	$8,105	71	$5,050	73	$5,663	79	$6,638
Services <=300kW - >50kW	81	$15,831	83	$18,516	83	$9,449	66	$16,491
Services over 300kW	36	($10,165)	26	$2,282	36	$1,685	57	$26,901
Services <=50kW	43	$5,552	39	$5,184	57	$7,159	51	$5,279
Embedded Generation	0	$0	0	$0	0	$0	20	$0
Other Customer Requests	12	$137,540	7	($31,237)	8	$25,065	9	$30,699
Services Customer Owned Sub-Station	6	($71,442)	2	$46,160	9	($23,878)	5	($30,041)
Total	**209**		**228**		**266**		**287**	

2.0-VECC-11

Reference: E2/T6/S3

a) Please provide a list of road relocations forecast for each of the years 2014 through 2019. For each road please provide the basis for believing the project will be need to be completed in that year.

Response:

a) Horizon Utilities provides a list of known road relocations forecast for each of the years 2014 through 2019 for the City of Hamilton, the City of St. Catharines, and the Region of Niagara. The planning timelines for road relocation projects often result in Horizon Utilities receiving notification between six and 24 months prior to the start of the projects.

Horizon Utilities is an active participant in two Public Utility Coordinating Committees ("PUCCs"): 1) the City of Hamilton and 2) the City of St. Catharines and Region of Niagara. The PUCCs are a forum for city officials, regional officials and utilities to: meet (on a quarterly basis) and discuss common issues; share project information; develop solutions to issues or project related matters; and review project schedules. It is either through these forums or through direct communication with the City of Hamilton, the City of St. Catharines or Region of Niagara that Horizon Utilities obtains forecasts, updates, and budget confirmation for proposed road relocation projects; and on this basis that Horizon Utilities believes that the road relocations listed below will need to be completed in a particular year.

Additional road relocation projects for the later years in the rate plan will be identified through this forum on a go-forward basis.

1 **Table 1: Road Relocations**

Project Year	City of Hamilton	City of St. Catharines	Region of Niagara
2014	West 5th Street	Burbank Drive	Lakeshore Road, Phase 2
	Mohawk Road East	Garden Park	St. David's Road
	Cannon Street East	George Street	Burgoyne Bridge
	Cope Street	Lorne Street	
	Centennial Parkway - CNR	Queenston Street	
	Centennial Parkway		
	Upper Lake Avenue		
	Birch Avenue		
	York Boulevard		
	Park Street		
2015	Concession Street	Oakdale Avenue	Burgoyne Bridge, Phase 2
	Greenhill Avenue	Buckland Street	Glendale Avenue, Phase 2
	Patrick Street	Eastchester Avenue	Martindale Road, Phase 1
	King Street East	Westchester Avenue	
	Mountain Brow Boulevard	Abraham Drive	
	Broker Drive	Beverly Street	
	Highway 5 & 6 Interchange	Brisson Lane	
	Birch Avenue	Carlisle Street	
	Bowman Street	Carlton Park Drive	
	Ainslie Avenue	Catherine Street	
		Cherie Road	
		Chestnut Lane	
		Crestcome Road	
		Eastchester Avenue	
		First Street	
		Forest Hill Road	
		Glendale Avenue PRV	
		Henley Drive	
		Hillcrest Avenue	

Project Year	City of Hamilton	City of St. Catharines	Region of Niagara
2016	Burlington Street, Phase 1	Hillside Drive	Seventh Street
	Industrial Drive	Hiscott Street	Fourth Avenue
	Lakeshore Road	Lakeshore Road	Main Street
	Mountain Avenue	Main Street	Lakeshore Road Phase 3
	Gemma Avenue	McGuire Street	Martindale Road, Phase 2
	Highway 5 & 6 Interchange	Niagara Street	
	Brampton Street	Parnell Road	
	Parkside Drive	Petrie Street	
		Philip Street	
		Riverview Boulevard	
		Samuel Court	
		St. David's Road	
		St. Paul Street West	
		The Parkway	
		Village Road	
		Windermere Road	
		YMCA Drive	
2017	Gage Avenue		St. Paul Street
	Industrial Drive		
	Depew Street		
	Burlington Street, Phase 2		
2018	Burlington Street, Phase 3		Carlton Street
	Industrial Drive		
2019			Carlton Street Phase 2
			Queenston Street

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2.0-VECC-12

Reference: E2/T6/S3/

a) Substation infrastructure renewal has been identified as a major project by Horizon. Table 2-80 shows a significant increase in spending as compared to past years. Given these circumstances please explain why in 2013 Horizon spent considerably less on this project category as compared to prior and post years.

b) Similarly pole replacement between 2011 and 2013 was significantly below the proposed spending during the 5 year rate plan. Why?

c) For XPLE Cable renewal projects Table 2-99 shows a similar pattern of significantly lower spending in the years preceding 2015. Please explain.

Response:

a) Substation infrastructure renewal projects, as identified in Table 2-80 of Exhibit 2, Tab 6, Schedule 3, were lower in 2013 compared to previous and future years to mitigate increased expenditures related to higher priority substation breaker and relay renewal projects. Breakers and protection relays are major substation components responsible for the protection and control of the distribution system. Failure of a breaker would result in significant service interruptions to customers (each breaker serves approximately 500 customers on average).

Horizon Utilities' total substation renewal investment includes Substation Infrastructure Renewal and Substation Breaker and Relay Renewal. Horizon Utilities' investment in substation renewal was highest in 2013 as identified in Table 1 below.

Table 1: Substation Renewal Investments

	Substation Infrastructure Renewal $	Substation Breaker and Relay Renewal $	Total Substation Investment $
2011 Actual	326,000	223,000	549,000
2012 Actual	305,000	1,998,000	2,303,000
2013 Actual	168,507	3,864,456	4,032,963
2014 Bridge Year	455,503	-	455,503
2015	464,000	-	464,000
2016	473,000	-	473,000
2017	482,000	-	482,000
2018	491,000	-	491,000
2019	500,000	-	500,000

b) Some pole replacements were deferred in the years 2011 to 2013 to mitigate higher than planned System Access expenditures which are outside of Horizon Utilities' control. Horizon Utilities provides the number of poles replaced through the Pole Residual Program in each of 2010 to 2013 and the forecast for the five years of the rate plan term (2015-2019) in Table 2 below.

Table 2: Pole Replacements 2010 - 2019

	Pole Replacement Volume
2010 Actual	117
2011 Actual	79
2012 Actual	87
2013 Actual	70
2014 Bridge Year	128
2015	128
2016	128
2017	128
2018	128
2019	128

The volume of poles replaced in the Pole Residual Program is determined by the results of the annual pole testing program. The volume of poles requiring replacement in a given year can be deferred to future years but this can only be accommodated for a short number of years. Deferral for multiple years results in:

- Increased risk to service interruptions to customers due to an increased number of poles, identified through testing as having a high risk of failure, remain in service; and
- Increased volume of poles requiring replacement in future years which creates a backlog of investment that must be addressed in future years.

Horizon Utilities has increased the forecasted volume of replacements in 2014 to 2019 to address the backlog of replacements resulting from deferrals in 2011 to 2013.

c) Cross-linked Polyethylene ("XLPE") cable renewal expenditures were lower in the years preceding 2015 because of the investment prioritization identified by Horizon Utilities in its last CoS application (EB-2010-0103). Investment in substation asset renewal was a higher priority. Horizon Utilities planned to and did commence XLPE renewal following the completion of the substation renewal investments in 2013. The need for increased investment in the 2015-2019 Test Years has been confirmed by the Kinectrics' Asset Condition Assessment ("ACA"), and referenced in Exhibit 2, Tab 6, Appendix 2-4, Section 3.5.3.

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3.0-VECC-13

Reference: E3/T1/S1/pg.4

Table 3.4 reports Load Transfer Revenue for 2012 and 2013 but not for 2011.

a) Please explain more fully the basis for the 2012 and 2013 load transfer revenues.

b) Are load transfer revenues expected to occur over the 2015-2019 period? If yes, how much and, if not, why not?

c) If yes, how are they accounted for in Horizon's Application?

Response:

a) Horizon Utilities' 2012 and 2013 load transfer revenues are a result of Other Utility Long Term Load Transfer Customers served by Horizon Utilities. The reduction in load transfer revenue from 2012 to 2013 is principally a result of the elimination of load transfers.

b) Horizon Utilities provided information on the Other Utility Long Term Load Transfer Customers Served by Horizon Utilities that it expects to occur over the 2015-2019 period in Exhibit 1, Tab 12, Schedule 4. The Annual estimated revenue is expected to be $41,496.

c) Horizon Utilities has not specifically accounted for Load Transfer Revenue in its 2015 Cost of Service Application. The distribution rates that Horizon Utilities has calculated to support the revenue requirement will be applied to those customers that Horizon Utilities service outside its service territory which are estimated to be $41,496 annually.

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3.0-VECC-14

Reference: E3/T1/S2/pg.3

a) Did Horizon's billing system record actual monthly sales by customer class for the years 2007-2013?

b) If not, how were the "monthly class-specific sales from 2007 to 2013" determined?

Response:

a) Horizon Utilities' billing system does record actual monthly sales by customer class for the years 2007-2013 as filed in Appendix 3-5 in Exhibit 3, Tab 1.

b) Not applicable.

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3.0-VECC-15

Reference: E3/T1/S2/pg.3-4
EB-2014-0002 Horizon_3.4 Price Data Excel File

a) Please explain more fully how the retail price of electricity for each historic month was determined and provide a sample calculation. In doing so please clarify if the historic and forecast values were expressed in nominal or real terms (i.e. adjusted for inflation).

b) Please explain why the retail price variable used only includes the commodity cost as opposed to the full cost of electricity to residential customers.

c) Page 4 states that the “number of customers” is captured in the population explanatory variable. However, per page 3, none of the equations estimated include population as an explanatory variable. Please reconcile.

Response:

a) Horizon Utilities calculated the retail price of electricity by first determining the average month rate by dividing the total monthly revenue by kWh sales. The average rate was then adjusted for inflation by deflating the rate by the current Consumer Price Index (CPI). The final price was generated as a 12-month moving average of the real average rate. Horizon Utilities used a 12 month moving average to capture that customer responses to price fluctuations are not immediate. A current customer bill includes usage from prior months which results in a delay in the change in usage patterns that are attributable to price changes. By using a 12-month moving average, Horizon Utilities captures that customers respond to price changes over time. Horizon Utilities has provided a sample calculation of the price calculation in 3.0-VECC-15a_Attch 1_Retail Price of Electricity Derivation.

b) The retail price variable used only includes the commodity costs as opposed to the full cost of electricity to residential customers due to the fact that the principal driver in historic variation in price has been commodity costs. In a regression model, the change in usage is driven by the change in price – not by its absolute level. By using the commodity costs, the price variable is statistically significant and has a reasonable impact as measured by the price elasticity as provided in 3.0-VECC-15b_Attch 2_Price Elasticity. The price response is small with close to a -0.1 price elasticity. For the bridge and test year forecasts, Horizon Utilities’ assumes constant real prices. Given that there are no changes in real prices, there is no change in the sales forecast; a constant real price forecast has no impact on the bridge and test year forecast.

c) Please refer to Horizon Utilities' response to part b) of 3-EnergyProbe-18.

3.0-VECC-15a_Attch 1_Retail Price of Electricity Derivation

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Year	Month	CPI	Deflator	Res_Nom	SmlGS_Nom	Res_Real	SmlGS_Real	ResPrice	SmlGS_Price
		A	B	C	D	E=C/B	F=D/B	Average E (2011/12 - 2012/11)	Average F (2011/12 - 2012/11)
2011	12	1.21	1.19	0.1432	0.1312	0.1207	0.1106		
2012	1	1.21	1.19	0.1383	0.1278	0.1164	0.1076		
2012	2	1.21	1.19	0.1459	0.1281	0.1226	0.1076		
2012	3	1.22	1.19	0.1439	0.1285	0.1207	0.1078		
2012	4	1.22	1.20	0.1509	0.1303	0.1263	0.1090		
2012	5	1.22	1.20	0.1480	0.1383	0.1236	0.1155		
2012	6	1.22	1.20	0.1426	0.1367	0.1192	0.1143		
2012	7	1.22	1.20	0.1407	0.1346	0.1177	0.1127		
2012	8	1.22	1.19	0.1408	0.1377	0.1180	0.1154		
2012	9	1.22	1.19	0.1476	0.1386	0.1236	0.1161		
2012	10	1.22	1.19	0.1426	0.1406	0.1194	0.1177		
2012	11	1.22	1.19	0.1467	0.1371	0.1228	0.1148		
2012	12	1.22	1.20	0.1424	0.1367	0.1190	0.1142	0.1209	0.1124

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3.0-VECC-15b_Attch 2_Price Elasticity

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Residential Model Statistics Elasticity

Variable	Coefficient	Mean	Elasticity
mSales.Days	4,407,151.37	30.440	0.977
mLight.HLight	(117,856.05)	371.814	(0.319)
mWthr.CDD18	547,729.00	23.036	0.092
mWthr.HDD13	25,113.75	213.793	0.039
mEcon.RPDI	3.20	14,523,854.070	0.339
mEcon.RPDI_Trend	(0.05)	110,275,266.223	(0.038)
mEcon.ResPrice_Idx	(12,143,705.14)	0.976	(0.086)
mBin.Mar07	19,552,566.15	0.012	0.002
mBin.Sep07	(24,564,657.63)	0.012	(0.002)
mBin.Apr12	(25,093,959.11)	0.012	(0.002)

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3.0-VECC-16

Reference: 3/T1/S2/pg.7

a) What is the electricity price forecast used for 2014 through 2019 and what is its source/basis?

Response:

a) The source/basis of the electricity price forecast used for 2014 through 2019 is internal revenue per kWh calculation used to populate the green columns in Appendix 3-4 of Exhibit 3. The price is based on historical price data which is in itself estimated from the reported monthly revenue and sales. The price series is then adjusted by the Deflator to calculate the real average rate. The real average rate is held constant beginning in January 2014. The monthly price series increases somewhat through 2014 and 2015 and then is flat through the rest of the rate plan term. Initial price increase is an outcome of the calculation where Horizon Utilities' defines price as a 12-month moving average of the real average rate.

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3.0-VECC-17

Reference: E3/T1/S2/pg.9
E4/T9/Appendix 4-13/pg.8

a) The 2011 and 2012 CDM program saving shown in Table 3-5 do not match those in the OPA's Report (Appendix 4-13). Please reconcile.

b) What is the basis for the 2013 and 2014 CDM programs savings shown in Table 3-5?

c) Please provide a version of Table 3-5 where the savings (kWh) for programs undertaken in 2011-2014 are also shown for the years 2015-2019.

d) With respect to the last section of Table 3-5, please explain why the LRAM for 2014 is not the 2011 through 2014 savings reported in the earlier sections, i.e. 110,619,741 kWh.

e) With respect to the last section of Table 3-5, please explain why the 2014 manual adjustment to the 2014 load forecast isn't 14,071,000 kWh (i.e. based on the ½ year rule).

f) Please provide copies of any OPA Reports regarding Horizon's CDM achievements in 2013.

Response:

a) The results shown in the OPA's report (Appendix 4-13) include an adjustment of 2,151,259 kWh that belongs in 2011 results and recognized in 2012. For 2011 the achieved kWh savings is 32,404,444 kWh (rounded to $32,400,000 in table 3-5) plus the adjustment of 2,151,259 kWh totalling 34,555,703 kWh (34,551,259 per table 3-5). This adjustment to previous year's verified results of 2,151,259 kWh was inadvertently applied by Horizon Utilities to both 2011 and 2012 in Horizon Utilities' Table 3-5. For 2012, the achieved kWh savings is 16,764,001 kWh.

b) The basis of the 2013 and 2014 CDM program forecast savings in Table 3-5 is based on Horizon Utilities forecast of achieving 100% of its energy target.

c) The impact of past CDM activity is embedded in the model coefficients of the Residential, GS<50kW, and GS>50kW regression models, as the models are estimated with actual data which reflects the impact of past CDM activity. The incremental CDM savings for the 2014 Bridge Year and the 2015 through 2019 Test Years are provided in Exhibit 3, Tab 1, Schedule 2, Page 10 of 33, Table 3-6 and the persistence of those specific CDM activities over the application period are provided in Exhibit 3, Tab 1, Schedule 2, Page 11 of 33, Table 3-7.

d) The 110,619,741 kWh is representative of only those CDM savings occurring in 2014 based on cumulative 2011, 2012, 2013 and incremental 2014 CDM savings. The total true up expected after 2014 would be based on the total cumulative effect of CDM savings achieved from years 2011 to 2014 as compared to the CDM target of 281,420,000 kWh assigned to Horizon Utilities.

e) Horizon Utilities has followed the Board "Guidelines for Electricity Distributor Conservation and Demand Management" EB-2012-0003 dated April 26, 2012 when preparing its LRAMVA summary in Exhibit 9 and Table 3-5. In EB-2010-0131 Horizon Utilities included 100% of its CDM savings target into the 2011 load forecast model for the years 2011 to 2014 and it was anticipated that verified 2011 to 2014 CDM results would be used to recognize actual CDM savings and any difference to forecast would be recorded in the Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA") allocated to each customer class as per the LRAMVA statement in Exhibit 9. The true up for 2014 would be based on verified CDM savings reported in the Horizon Utilities' CDM Annual Report submitted by September 30, 2015. Due to the inclusion of 100% of the 2011 to 2014 CDM savings target within the load forecast model in 2011 the full complement of 2014 CDM savings would be used in the true up process against the amounts recorded in the LRAMVA. Timing of the final verified 2014 program year CDM savings is September 1, 2015.

f) Horizon Utilities has attached the Ontario Power Authority Conservation & Demand Management Status Report as 3.0-VECC-17f_Attch 1_Ontario Power Authority Conservation & Demand Management Status Report which includes the OPA's preliminary results to the end of March 31, 2014.

3.0-VECC-17_Attch 1_Ontario Power Authority Conservation & Demand Management Status Report

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Ontario Power Authority

Conservation & Demand Management Status Report

Q1 2014 Preliminary Results Update

Horizon Utilities Corporation

Unverified OPA-Contracted Province-Wide CDM Program Progress at a Glance

Unverified Progress to Targets	Incremental Q1-2014	Program-to-Date Progress Towards OEB Target				Rank (of 76)
		Scenario 1		Scenario 2		
		Savings	%	Savings	%	Scenario 2
Net Peak Demand Savings (MW)	**20.0**	**36.3**	60%	**36.3**	60%	**11**
Net Energy Savings (GWh)	**2.9**	**245.9**	87%	**245.9**	87%	**33**

Program-to-Date towards Target: Combination of verified (2011-12) and unverified (2013-14) results. To align with savings counted towards OEB targets, peak demand is represented by annual savings in 2014 and energy is represented by the cumulative savings from 2011-2014.

Scenario 1: Assumes that demand response resources have a persistence of 1 year. Official reporting policy for demand response resources.

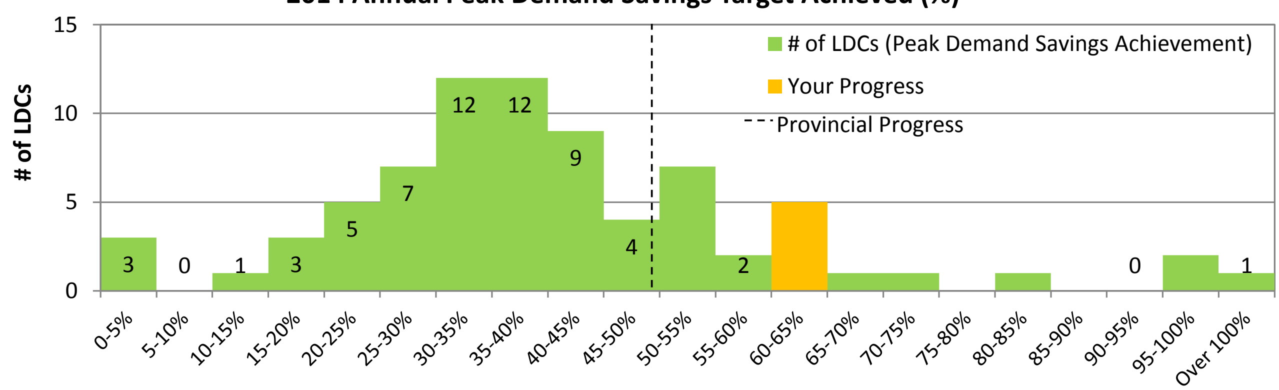
Scenario 2: Assumes that demand response resources remain in your territory until 2014. Used to better assess progress towards demand targets.

Rank: Sorts each LDC by % of peak demand or energy target achieved as of the current reporting period using Scenario 2.

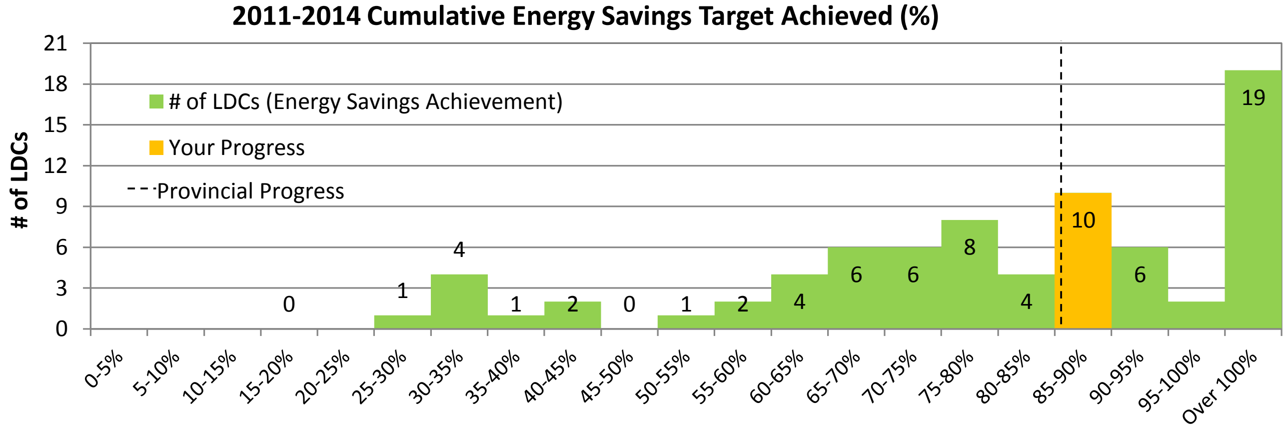
Comparison: Your Achievement vs. LDC Community Achievement

The following graphs assume that demand response resources remain in your territory until 2014 (aligns with Scenario 2)

2014 Annual Peak Demand Savings Target Achieved (%)



2011-2014 Cumulative Energy Savings Target Achieved (%)



Questions? Please check the "About this Report" Section on page 2, Table 5 on page 9 and "Reporting Methodology" on page 10.
More Questions? Please contact LDC.Support@powerauthority.on.ca

Message from the Vice President

I am pleased to present your Q1 2014 LDC Status Update. We continue to progress well across all sectors. Provincially we have achieved 86% of the cumulative 6,000 GWh energy target and progress towards the 1,330 MW demand target increased from last quarter to 49%.

A few highlights of the first quarter of 2014:

- Over half of the LDCs have achieved more than 80% of their energy targets and 19 LDCs have exceeded their energy target
- 13% more projects in Retrofit compared to Q1 2013
- 4.5 million coupon booklets were mailed out to residential customers across Ontario
- 100 Energy Managers (EEMs, REMs, KAMs, EESPs) and LDC sales staff attended the Variable Frequency Drive session as part of a series of five high impact technology workshops in 2014

We are striving to have a successful 2014 by accelerating participation before the end of the year. We would like to hear your ideas and success stories so we can share these experiences across the province.

Please contact the OPA Conservation Business Development team at ldc.support@powerauthority.on.ca with any questions regarding this report.

Congratulations on another successful quarter and wishing you a great Q2!

Sincerely,

Andrew Pride

About this Report

This report contains:

- Peak demand and energy savings for OPA-Contracted Province-Wide programs (does not include Ontario Energy Board (OEB) approved CDM programs or other LDC conservation efforts)
- Progress as of the end of Q1 2014 using unverified quarterly results for 2013-14 and final verified results for 2011-12
- Program activity data (i.e. projects completed, appliances picked up) completed on or before March 31st, 2014 and received and entered into the OPA processing systems as per the dates specified in Table 5
- Updates to the previous quarters' participation as a result of further data received
- Information to assist the LDC in reconciling internal data sources with the data contained in this report. Table 5 contains:

    1. The date in which savings are considered to 'start';
    2. At what point the data becomes available to the OPA;
    3. The expected probability and magnitude of updates to the data as more information becomes available.
- iCON CRM Post Stage Retrofit Report data queried on April 1st, 2014
- Preliminary results for peaksaverPLUS® representing customers that have signed a Participant Agreement and information has been successfully uploaded into the RDR settlement system
- peaksaver PLUS® reporting is split into two line items: Switch/Thermostat and IHD

2011-2014 Summary: Net Peak Demand Savings Achieved (MW)

This section provides a portfolio level view of net peak demand savings procured to date through Tier 1 programs.
Table 1 presents:

- Net peak demand savings results from 2011 to Q1 2014 listed by implementation period, status (i.e. final or reported) and summarized by resource type (i.e. energy efficiency or demand response)
- Net annual peak demand savings that are expected to persist through to 2014 from program activity completed as of Q4 2013 using both Scenarios 1 and 2
- A comparison between reported, unverified results and final, verified results
- Energy efficiency resources reported with persistence according to the effective useful life of the technology

Figure 1 presents:

- Net peak demand savings results from 2011 to date using Scenario 1 for demand response resources (persistence of 1 year)

Please note: Demand response resources are only presented in the final quarter of each year and the current reporting quarter (i.e. Q4 2011, Q4 2012, and Q3 2013). Figures below and tables 3B and 4B present demand response in each quarter to display any changes that may have occurred quarter over quarter.

Table 1A: Net Peak Demand Savings at the End-User Level (MW)

#	Implementation Period	Annual (MW)				
		Scenario 1				Scenario 2
		2011	2012	2013	2014	2014
1	2011 - Final*	12.0	6.9	6.9	6.8	6.8
2	2012 - Final†	0.2	13.6	3.9	3.8	3.8
3	2013 - Reported - Quarter 1			1.1	1.1	1.1
4	2013 - Reported - Quarter 2			1.4	1.4	1.4
5	2013 - Reported - Quarter 3			1.2	1.2	1.2
6	2013 - Reported - Quarter 4			21.3	1.9	1.9
4	2014 - Reported - Quarter 1				20.0	20.0
	Energy Efficiency	7.1	10.8	16.4	16.7	16.7
	Demand Response	5.1	9.7	19.4	19.5	19.5
	Net Annual Peak Demand Savings	12.2	20.5	35.8	36.3	36.3
	Unverified Net Annual Peak Demand Savings in 2014:				**36.3**	**36.3**
	2014 Annual Peak Demand Savings Target as per OEB:				**60.4**	**60.4**
	Unverified 2014 Peak Demand Savings Target Achieved (%):				**60%**	**60%**
	Incremental Reported (Unverified)	12.7	14.0	25.0	20.0	
	Incremental Final (Verified)	12.0	13.6	n/a	n/a	

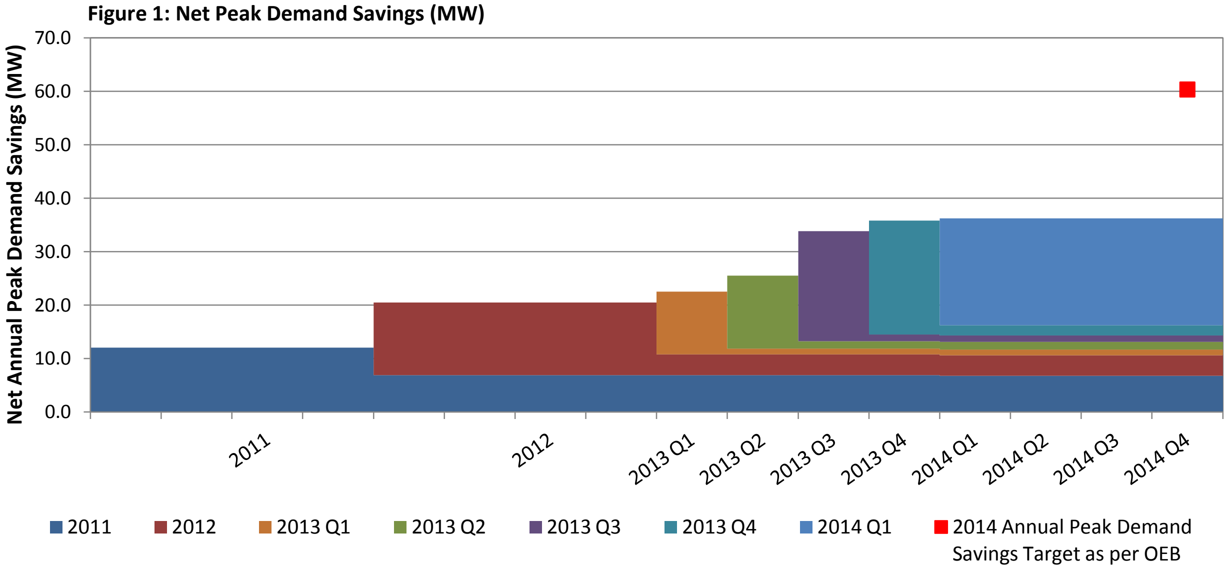
* Drop from 2011 to 2012 due to demand response persistence assumption (scenario 1)
† Includes adjustments to previous year's verified results

Table 1B: Peak Demand Savings from DR3 Resources

Reported DR3 (Ex Ante) (MW)**	14.65
Contracted DR3 (MW)**	16.9

** Consistent with monthly DR3 reports at the end of each quarter

Figure 1: Net Peak Demand Savings (MW)



2011-2014 Summary: Net Energy Savings Achieved (GWh)

This section provides a portfolio level view of net energy savings procured to date through Tier 1 programs.

Table 2 presents net annual energy savings results from 2011 to date listed by implementation period, status (i.e. final or reported) and summarized by resource type. This table aligns with Scenario 1 and presents 2011-2014 net cumulative energy savings expected in 2014 from program activity completed to date. At the bottom of the table a comparison is made between reported results (unverified) and final results (verified) for 2011, 2012, and 2013 year-to-date.

Table 2: Net Energy Savings at the End-User Level (GWh)

#	Implementation Period	Annual (GWh)				Cumulative (GWh)
		2011	2012	2013	2014	2011-2014
1	2011 - Final	32.4	32.2	32.1	31.8	128.5
2	2012 - Final†	2.2	18.9	18.7	18.5	58.2
3	2013 - Reported - Quarter 1			4.6	4.6	9.2
4	2013 - Reported - Quarter 2			6.5	6.5	13.0
5	2013 - Reported - Quarter 3			5.6	5.6	11.1
6	2013 - Reported - Quarter 4			11.7	11.3	23.0
7	2014 - Reported - Quarter 1				2.9	2.9
	Energy Efficiency	34.3	50.9	78.7	80.7	244.7
	Demand Response	0.2	0.2	0.4	0.4	1.2
	Net Energy Savings	34.6	51.1	79.1	81.1	245.9
	Unverified Net Cumulative Energy Savings 2011-2014:					**245.9**
	2011-2014 Cumulative Energy Savings Target as per OEB:					**281.4**
	Unverified 2011-2014 Cumulative Energy Target Achieved (%):					**87%**
	Incremental Reported (Unverified)	8.1	17.4	28.4	2.9	
	Incremental Final (Verified)	32.4	18.9	n/a	n/a	

† Includes adjustments to previous year's verified results

Figure 2: Net Cumulative Energy Savings (GWh)

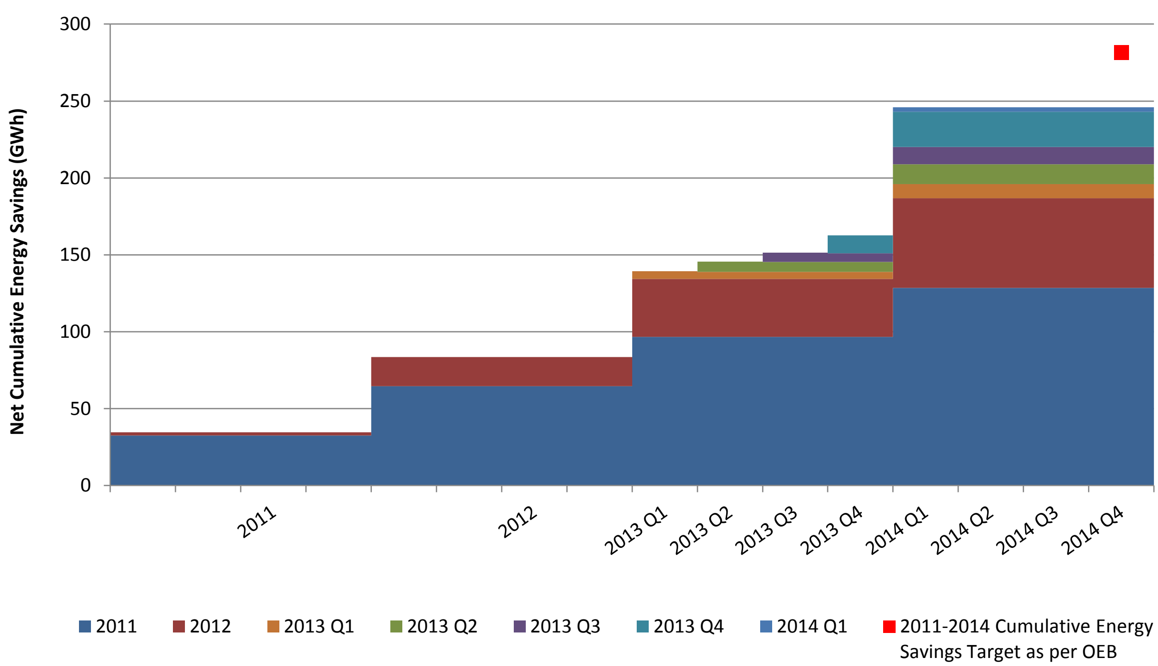


Table 3A: Horizon Utilities Corporation Initiative and Program Level Savings by Year (Scenario 1)

#	Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Unverified Progress to Target (excludes DR) 2014 Net Annual Peak Demand Savings (kW)	Program-to-Date Unverified Progress to Target (excludes DR) 2011-2014 Net Cumulative Energy Savings (kWh)
			2011 Adj.*	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program																
1	Appliance Retirement	Appliances	3,034	1,671	877	83	172	96	51	5	1,238,865	669,778	350,968	33,063	318	7,695,954
2	Appliance Exchange	Appliances	186	131	177	-	18	19	26	-	21,438	33,812	46,910	-	51	269,818
3	HVAC Incentives	Equipment	5,029	5,007	4,800	433	1,693	1,091	1,046	100	3,070,047	1,843,136	1,768,695	174,712	3,931	21,521,698
4	Conservation Instant Coupon Booklet	Measures	21,872	1,249	21,336	2,182	50	9	30	3	810,293	56,527	601,343	73,927	92	4,687,370
5	Bi-Annual Retailer Event	Measures	38,494	42,891	40,561	-	68	60	63	-	1,188,091	1,082,743	1,203,525	-	190	10,407,644
6	Retailer Co-op	Items	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Residential Demand Response (switch/pstat)†	Devices	1,952	5,393	8,399	8,399	1,093	2,699	4,871	4,871	2,830	13,650	38,971	38,971	4,871	94,423
8	Residential Demand Response (IHD)	Devices	-	3,855	4,408	-	-	-	-	-	-	-	-	-	-	-
9	Residential New Construction	Homes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Consumer Program Total							**3,093**	**3,975**	**6,087**	**4,980**	**6,331,565**	**3,699,646**	**4,010,413**	**320,674**	**9,453**	**44,676,907**
Business Program																
10	Retrofit	Projects	87	178	325	27	857	1,659	2,941	217	4,805,916	9,600,471	16,705,540	1,424,003	5,611	82,581,332
11	Direct Install Lighting	Projects	715	662	416	158	661	550	446	156	1,693,346	1,875,038	1,547,779	563,450	1,680	15,590,522
12	Building Commissioning	Buildings	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	New Construction	Buildings	-	2	3	1	-	0	10	2	-	1,331	25,958	7,647	13	63,555
14	Energy Audit	Audits	15	3	14	2	-	16	73	10	-	75,529	352,464	50,352	99	981,866
15	Small Commercial Demand Response (switch/pstat)†	Devices	-	9	17	17	-	6	11	11	-	33	87	87	11	207
16	Small Commercial Demand Response (IHD)	Devices	-	-	5	-	-	-	-	-	-	-	-	-	-	-
17	Demand Response 3†	Facilities	5	4	5	5	536	531	678	788	20,936	7,718	9,852	11,459	788	49,965
Business Program Total							**2,054**	**2,762**	**4,159**	**1,185**	**6,520,199**	**11,560,119**	**18,641,680**	**2,056,998**	**8,202**	**99,267,447**
Industrial Program																
18	Process & System Upgrades	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Monitoring & Targeting	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Energy Manager	Projects	-	3	5	-	-	60	28	-	-	479,921	220,003	-	88	1,879,771
21	Retrofit	Projects	15	-	-	-	70	-	-	-	402,527	-	-	-	70	1,610,107
22	Demand Response 3†	Facilities	6	7	9	9	3,498	6,445	13,851	13,861	205,346	155,311	333,808	334,043	13,861	1,028,508
Industrial Program Total							**3,568**	**6,505**	**13,879**	**13,861**	**607,873**	**635,233**	**553,811**	**334,043**	**14,019**	**4,518,386**
Home Assistance Program																
23	Home Assistance Program	Homes	-	235	3,331	170	-	24	915	8	-	286,839	5,149,023	141,935	947	11,300,497
Home Assistance Program Total							**-**	**24**	**915**	**8**	**-**	**286,839**	**5,149,023**	**141,935**	**947**	**11,300,497**
Aboriginal Program																
24	Aboriginal Program	Homes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aboriginal Program Total							**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Pre-2011 Programs completed in 2011																
25	Electricity Retrofit Incentive Program	Projects	118	-	-	-	3,066	-	-	-	17,700,219	-	-	-	3,066	70,800,874
26	High Performance New Construction	Projects	8	3	-	-	242	146	-	-	1,244,589	582,164	-	-	389	6,724,846
27	Toronto Comprehensive	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Multifamily Energy Efficiency Rebates	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	LDC Custom Programs	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pre-2011 Programs completed in 2011 Total							**3,308**	**146**	**-**	**-**	**18,944,807**	**582,164**	**-**	**-**	**3,455**	**77,525,720**
Other																
30	Program Enabled Savings	Projects	-	-	-		-	-	-	-	-	-	-	-	-	-
31	Time-of-Use Savings	Homes	-	-	-		-	-	-	-	-	-	-	-	-	-
Other Total							**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Adjustment to Previous Year's Verified Results							**-**	**193**	**-**	**-**	**-**	**2,151,259**	**-**	**-**	**191**	**8,600,509**
Energy Efficiency Total							**6,896**	**3,730**	**5,629**	**502**	**32,175,331**	**16,587,289**	**27,972,209**	**2,469,090**	**16,545**	**236,115,854**
Demand Response Total (Scenario 1)							**5,128**	**9,681**	**19,411**	**19,532**	**229,113**	**176,712**	**382,718**	**384,560**	**19,531**	**1,173,103**
OPA-Contracted LDC Portfolio Total							**12,023**	**13,604**	**25,040**	**20,034**	**32,404,444**	**18,915,260**	**28,354,927**	**2,853,650**	**36,267**	**245,889,466**
														Full OEB Target:	**60,360**	**281,420,000**
														% of Full OEB Target Achieved to Date (Scenario 1):	**60%**	**87%**

†Activity and savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Due to the limited timeframe of data, which didn't include the summer months, 2012 IHD results have been deemed inconclusive. The IHD line item for 2012 & 2013 will be left blank until the savings are quantified in the 2013 evaluation.

Table 3B: Horizon Utilities Corporation Initiative and Program Level Savings by Quarter for current reporting year**

#	Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
			Q1 2014	Q2 2014	Q3 2014	Q4 2014	Q1 2014	Q2 2014	Q3 2014	Q4 2014	Q1 2014	Q2 2014	Q3 2014	Q4 2014
Consumer Program														
1	Appliance Retirement	Appliances	83				5				33,063			
2	Appliance Exchange	Appliances	-				-				-			
3	HVAC Incentives	Equipment	433				100				174,712			
4	Conservation Instant Coupon Booklet	Measures	2,182				3				73,927			
5	Bi-Annual Retailer Event	Measures	-				-				-			
6	Retailer Co-op	Items	-				-				-			
7	Residential Demand Response (switch/pstat)†	Devices	8,399				4,871				38,971			
8	Residential Demand Response (IHD)	Devices	-				-				-			
9	Residential New Construction	Homes	-				-				-			
Consumer Program Total							**4,980**	-	-	-	**320,674**	-	-	-
Business Program														
10	Retrofit	Projects	27				217				1,424,003			
11	Direct Install Lighting	Projects	158				156				563,450			
12	Building Commissioning	Buildings	-				-				-			
13	New Construction	Buildings	1				2				7,647			
14	Energy Audit	Audits	2				10				50,352			
15	Small Commercial Demand Response (switch/pstat)†	Devices	17				11				87			
16	Small Commercial Demand Response (IHD)	Devices	-				-				-			
17	Demand Response 3†	Facilities	5				788				11,459			
Business Program Total							**1,185**	-	-	-	**2,056,998**	-	-	-
Industrial Program														
18	Process & System Upgrades	Projects	-				-				-			
19	Monitoring & Targeting	Projects	-				-				-			
20	Energy Manager	Projects	-				-				-			
21	Retrofit	Projects	-				-				-			
22	Demand Response 3†	Facilities	9				13,861				334,043			
Industrial Program Total							**13,861**	-	-	-	**334,043**	-	-	-
Home Assistance Program														
23	Home Assistance Program	Homes	170				8				141,935			
Home Assistance Program Total							**8**	-	-	-	**141,935**	-	-	-
Aboriginal Program														
24	Aboriginal Program	Homes	-				-				-			
Aboriginal Program Total							-	-	-	-	-	-	-	-
Pre-2011 Programs completed in 2011														
25	Electricity Retrofit Incentive Program	Projects	-				-				-			
26	High Performance New Construction	Projects	-				-				-			
27	Toronto Comprehensive	Projects	-				-				-			
28	Multifamily Energy Efficiency Rebates	Projects	-				-				-			
29	LDC Custom Programs	Projects	-				-				-			
Pre-2011 Programs completed in 2011 Total			-	-	-	-	-	-	-	-	-	-	-	-
Other														
30	Program Enabled Savings	Projects	-				-				-			
31	Time-of-Use Savings	Homes	-				-				-			
Other Total							-	-	-	-	-	-	-	-
Adjustment to Previous Year's Verified Results														
Energy Efficiency Total							**502**	-	-	-	**2,469,090**	-	-	-
Demand Response Total (Scenario 1)							**19,532**	-	-	-	**384,560**	-	-	-
OPA-Contracted LDC Portfolio Total							**20,034**	-	-	-	**2,853,650**	-	-	-

†Activity and savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

***Includes adjustments after Final Reports were issued**

**** Updates to the previous quarter's participation may occur as a result of further data received**

Table 4A: Province-Wide Initiative and Program Level Savings by Year (Scenario 1)

#	Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Unverified Progress to Target: 2014 Net Annual Peak Demand Savings (kW)	Program-to-Date Unverified Progress to Target: 2011-2014 Net Cumulative Energy Savings (kWh)
			2011 Adj.*	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program																
1	Appliance Retirement	Appliances	56,110	34,146	20,952	2,390	3,299	2,011	1,286	140	23,005,812	13,424,518	8,202,362	947,439	6,597	149,529,020
2	Appliance Exchange	Appliances	3,688	3,836	5,316	-	371	556	790	-	450,187	974,621	1,408,045	-	1,479	7,328,615
3	HVAC Incentives	Equipment	92,721	85,221	91,581	7,948	32,037	19,060	20,919	2,041	59,437,670	32,841,283	36,368,001	3,745,539	74,057	412,756,071
4	Conservation Instant Coupon Booklet	Measures	567,678	30,891	527,755	53,973	1,344	230	736	86	21,211,537	1,398,202	14,874,245	1,828,598	2,397	120,617,842
5	Bi-Annual Retailer Event	Measures	952,149	1,060,901	1,003,282	-	1,681	1,480	1,549	-	29,387,468	26,781,674	29,769,221	-	4,710	257,433,338
6	Retailer Co-op	Items	152	-	-	-	0	-	-	-	2,652	-	-	-	0	10,607
7	Residential Demand Response (switch/pstat)†	Devices	19,550	98,388	160,039	161,110	10,947	49,038	92,492	93,099	24,870	359,408	739,936	744,793	93,099	1,869,007
8	Residential Demand Response (IHD)	Devices	-	49,689	83,060	1,154	-	-	-	-	-	-	-	-	-	-
9	Residential New Construction	Homes	26	-	35	4	0	2	17	0	743	17,152	56,367	302	18	167,465
Consumer Program Total							**49,681**	**72,377**	**117,788**	**95,367**	**133,520,941**	**75,796,859**	**91,418,175**	**7,266,670**	**182,358**	**949,711,965**
Business Program																
10	Retrofit	Projects	2,819	5,605	7,884	872	24,467	61,147	61,771	6,394	136,002,258	314,922,468	362,222,076	52,995,889	152,183	2,258,087,499
11	Direct Install Lighting	Projects	20,741	18,494	17,891	4,774	23,724	15,284	18,179	5,058	61,076,701	57,345,798	64,764,767	18,706,236	54,418	539,308,639
12	Building Commissioning	Buildings	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	New Construction	Buildings	22	64	94	4	123	764	2,210	148	411,717	1,814,721	6,020,265	581,335	3,246	19,712,897
14	Energy Audit	Audits	196	280	402	199	-	1,450	2,090	1,035	-	7,049,351	10,120,752	5,010,024	4,575	46,399,582
15	Small Commercial Demand Response (switch/pstat)†	Devices	132	294	1,079	1,079	84	187	688	688	157	1,068	5,500	5,500	688	12,225
16	Small Commercial Demand Response (IHD)	Devices	-	-	279	1	-	-	-	-	-	-	-	-	-	-
17	Demand Response 3†	Facilities	145	151	175	179	16,218	19,389	25,054	25,609	633,421	281,823	364,174	372,231	25,609	1,651,649
Business Program Total							**64,617**	**98,221**	**109,993**	**38,932**	**198,124,253**	**381,415,230**	**443,497,534**	**77,671,216**	**240,718**	**2,865,172,490**
Industrial Program																
18	Process & System Upgrades	Projects	-	-	4	1	-	-	470	157	-	-	3,464,000	1,258,000	627	8,186,000
19	Monitoring & Targeting	Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Energy Manager	Projects	-	39	138	6	-	1,086	2,802	72	-	7,372,108	18,025,931	261,409	3,959	58,429,594
21	Retrofit	Projects	433	-	-	-	4,615	-	-	-	28,866,840	-	-	-	4,613	115,462,282
22	Demand Response 3†	Facilities	124	185	281	301	52,484	74,056	166,699	167,962	3,080,737	1,784,712	4,017,369	4,047,801	167,962	12,930,619
Industrial Program Total							**57,098**	**75,141**	**169,971**	**168,190**	**31,947,577**	**9,156,820**	**25,507,299**	**5,567,210**	**177,162**	**195,008,494**
Home Assistance Program																
23	Home Assistance Program	Homes	46	5,033	25,247	2,778	2	566	2,668	104	39,283	5,442,232	23,659,155	1,647,571	3,341	65,449,711
Home Assistance Program Total							**2**	**566**	**2,668**	**104**	**39,283**	**5,442,232**	**23,659,155**	**1,647,571**	**3,341**	**65,449,711**
Aboriginal Program																
24	Aboriginal Program	Homes	-	-	581	-	-	-	173	-	-	-	1,287,056	-	173	2,574,112
Aboriginal Program Total							**-**	**-**	**173**	**-**	**-**	**-**	**1,287,056**	**-**	**173**	**2,574,112**
Pre-2011 Programs completed in 2011																
24	Electricity Retrofit Incentive Program	Projects	2,028	-	-	-	21,662	-	-	-	121,138,219	-	-	-	21,662	484,552,876
25	High Performance New Construction	Projects	179	69	4	-	5,098	3,251	772	-	26,185,591	11,901,944	3,522,240	-	9,121	147,492,677
26	Toronto Comprehensive	Projects	577	-	-	-	15,805	-	-	-	86,964,886	-	-	-	15,805	347,859,545
27	Multifamily Energy Efficiency Rebates	Projects	110	-	-	-	1,981	-	-	-	7,595,683	-	-	-	1,981	30,382,733
28	LDC Custom Programs	Projects	8	-	-	-	399	-	-	-	1,367,170	-	-	-	399	5,468,679
Pre-2011 Programs completed in 2011 Total							**44,945**	**3,251**	**772**	**-**	**243,251,550**	**11,901,944**	**3,522,240**	**-**	**48,967**	**1,015,756,510**
Other																
29	Program Enabled Savings	Projects	-	-	-	-	-	2,304	-	-	-	1,188,362	-	-	2,304	3,565,086
30	Time-of-Use Savings	Homes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Total							**-**	**2,304**	**-**	**-**	**-**	**1,188,362**	**-**		**2,304**	**3,565,086**
Adjustment to Previous Year's Verified Results							**-**	**1,406**	**-**	**-**	**-**	**18,689,081**	**-**	**-**	**1,156**	**73,918,598**
Energy Efficiency Total							**136,610**	**109,191**	**116,432**	**15,236**	**603,144,419**	**482,474,435**	**583,764,481**	**86,982,342**	**367,667**	**5,080,774,868**
Demand Response Total (Scenario 1)							**79,733**	**142,670**	**284,933**	**287,357**	**3,739,185**	**2,427,011**	**5,126,979**	**5,170,326**	**287,357**	**16,463,500**
OPA-Contracted LDC Portfolio Total							**216,343**	**253,267**	**401,365**	**302,593**	**606,883,604**	**503,590,526**	**588,891,460**	**92,152,667**	**656,179**	**5,171,156,967**

†Activity and savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Due to the limited timeframe of data, which didn't include the summer months, 2012 IHD results have been deemed inconclusive. The IHD line item for 2012 & 2013 will be left blank until the savings are quantified in the 2013 evaluation.

	2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
Full OEB Target:	**1,330,000**	**6,000,000,000**
% of Full OEB Target Achieved to Date (Scenario 1):	**49%**	**86%**

Table 4B: Province-Wide Initiative and Program Level Savings by Quarter for Current Reporting Year**

#	Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
			Q1 2014	Q2 2014	Q3 2014	Q4 2014	Q1 2014	Q2 2014	Q3 2014	Q4 2014	Q1 2014	Q2 2014	Q3 2014	Q4 2014
Consumer Program														
1	Appliance Retirement	Appliances	2,390				140				947,439			
2	Appliance Exchange	Appliances	-				-				-			
3	HVAC Incentives	Equipment	7,948				2,041				3,745,539			
4	Conservation Instant Coupon Booklet	Measures	53,973				86				1,828,598			
5	Bi-Annual Retailer Event	Measures	-				-				-			
6	Retailer Co-op	Items	-				-				-			
7	Residential Demand Response (switch/pstat)†	Devices	161,110				93,099				744,793			
8	Residential Demand Response (IHD)	Devices	1,154				-				-			
9	Residential New Construction	Homes	4				0				302			
Consumer Program Total							**95,367**	**-**	**-**	**-**	**7,266,670**	**-**	**-**	**-**
Business Program														
10	Retrofit	Projects	872				6,394				52,995,889			
11	Direct Install Lighting	Projects	4,774				5,058				18,706,236			
12	Building Commissioning	Buildings	-				-				-			
13	New Construction	Buildings	4				148				581,335			
14	Energy Audit	Audits	199				1,035				5,010,024			
15	Small Commercial Demand Response (switch/pstat)†	Devices	1,079				688				5,500			
16	Small Commercial Demand Response (IHD)	Devices	1				-				-			
17	Demand Response 3†	Facilities	179				25,609				372,231			
Business Program Total							**38,932**	**-**	**-**	**-**	**77,671,216**	**-**	**-**	**-**
Industrial Program														
18	Process & System Upgrades	Projects	1				157				1,258,000			
19	Monitoring & Targeting	Projects	-				-				-			
20	Energy Manager	Projects	6				72				261,409			
21	Retrofit	Projects					-				-			
22	Demand Response 3†	Facilities	301				167,962				4,047,801			
Industrial Program Total							**168,190**	**-**	**-**	**-**	**5,567,210**	**-**	**-**	**-**
Home Assistance Program														
23	Home Assistance Program	Homes	2,778				104				1,647,571			
Home Assistance Program Total			**-**				**104**	**-**	**-**	**-**	**1,647,571**	**-**	**-**	**-**
Aboriginal Program														
24	Aboriginal Program	Homes	-				-				-			
Aboriginal Program Total							**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Pre-2011 Programs completed in 2011														
24	Electricity Retrofit Incentive Program	Projects	-				-				-			
25	High Performance New Construction	Projects	-				-				-			
26	Toronto Comprehensive	Projects	-				-				-			
27	Multifamily Energy Efficiency Rebates	Projects	-				-				-			
28	LDC Custom Programs	Projects	-				-				-			
Pre-2011 Programs completed in 2011 Total			**-**				**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Other														
29	Program Enabled Savings	Projects	-				-				-			
30	Time-of-Use Savings	Homes	-				-				-			
Other Total							**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Adjustment to Previous Year's Verified Results														
Energy Efficiency Total							**15,236**	**-**	**-**	**-**	**86,982,342**	**-**	**-**	**-**
Demand Response Total (Scenario 1)							**287,357**	**-**	**-**	**-**	**5,170,326**	**-**	**-**	**-**
OPA-Contracted LDC Portfolio Total							**302,593**	**-**	**-**	**-**	**92,152,667**	**-**	**-**	**-**

†Activity and savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

***Includes adjustments after Final Reports were issued**

**** Updates to the previous quarter's participation may occur as a result of additional data received**

Table 5: Data Qualifiers for Initiatives Currently In-Market & Likelihood of Additional Data

Data included in the Q1 2014 report includes all program activity completed (as per the savings 'start' date) on or before March 31st, 2014.

Initiative	Savings 'start' Date	Data Available	Additional Data Likely
Consumer Program			
Appliance Retirement	Pick-up date	When database is queried. Typically up-to-date.	Moderate
Appliance Exchange	Exchange event date	Once data is submitted to the OPA by retailers and undergoes QA/QC by OPA staff. Typically 3 - 6 months to receive and process all data.	High
HVAC Incentives	Installation date1	Rebate Status = Approved, Cheque Issued and Cheque Cashed; Typically 1 - 4 months delay.	High
Conservation Instant Coupon Booklet	Coupon redemption year	Once data is submitted to the OPA by retailers and undergoes QA/QC by OPA staff. Typically 3 - 6 months to receive and process all data.	High
Bi-Annual Retailer Event	Year and quarter of the event		High
Retailer co-op activities	Will vary by specific project	Will vary by specific project	Low
Residential Demand Response	Device installation date	Data successfully uploaded into RDR settlement system as of March 31st, 2014	High
Residential New Construction	Project completion	Preliminary Billing Report submitted to OPA	Low
Business (Commercial & Institutional) Program			
Retrofit	Actual project completion date	In the "Post Project Submission" Stage (excluding "Payment Denied by LDC", "Returned for Edit(s) by Participant" and "Participant Incentive Not Approved by LDC") within iCON CRM as of March 31st, 2014	Low
Direct Installed Lighting	Retrofit date	Work-order: invoiced, approved and paid to LDC. Typically 1.5 - 2 months delay. Any projects that are flagged as duplicates will not appear in reports until duplicates have been resolved.	High
Building Commissioning	Hand off date	Preliminary Billing Report submitted to OPA and reviewed	Moderate
New Construction	Actual project completion date	Preliminary Billing Report submitted to OPA and reviewed	Moderate
Energy Audit	Audit completion date	Preliminary Billing Report submitted to OPA and reviewed	Moderate
Small Commercial Demand Response	Device installation date	Data successfully uploaded into RDR settlement system	Moderate
Demand Response 3	Facility is available under contract	Facility available under contract with aggregator	Low
Industrial Program			
Process & System Upgrades	In-service date	Preliminary Billing Report submitted to OPA and reviewed	Low
Monitoring & Targeting	Project completion date	Preliminary Billing Report submitted to OPA and reviewed	Low
Energy Manager (EEM or REM)	Project completion date	Completed, non-incented projects submitted quarterly by Energy Manager.	High
Retrofit	All Retrofit projects are now reported under the Business Program		
Demand Response 3	Facility is available under contract	Facility available under contract with aggregator.	Low
Home Assistance Program			
Home Assistance Program	Project completion date	Preliminary Billing Report submitted to OPA and reviewed	High
Pre-2011 Projects Completed in 2011			
High Performance New Construction	Project completion date	Reviewed and processed from delivery agent, quarterly	Moderate

1: Monthly reports split savings into months using the approval date

Reporting Glossary

Annual: the peak demand or energy savings that occur in a given year (includes resource savings from new program activity in a given year and resource savings persisting from previous years). Annual savings for Demand Response resources represent the savings from all active facilities contracted since January 1, 2011.

Cumulative Energy Savings: represents the sum of the annual energy savings that accrue over a defined period (in the context of this report the defined period is 2011 - 2014). This concept does not apply to peak demand savings.

Current Reporting Period: the calendar quarter specified on page 1 of this report.

Effective Useful Life: detemines the persistence of savings for a given technology or initiative. Factors that may effect the useful life of a technology are typical use and operating hours, upcoming code changes, etc. Demand response resources are assumed to have a persistence of 1 year.

End-User Level: resource savings in this report are measured at the customer level as opposed to the generator level (the difference being line losses). All savings presented in this report are at the end-user level.

Final or Verified Savings: savings achieved that have undergone annual Evaluation, Measurement & Verification (EM&V) and thus have had activity audited and savings assumptions measured and verified.

Implementation Period: the particular calendar quarter or calendar year that conservation activity is achieved based on when the savings are considered to 'start' (please see table 5).

Incremental: the new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start' (please see table 5). Incremental savings for Demand Response resources represent the savings from all active facilities contracted since January 1, 2011 (i.e. Incremental = Annual for demand response only).

Initiative: a Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup).

Net Energy Savings (MWh): energy savings attributable to conservation and demand management activities net of free-riders, etc. Please refer to the webinars in the "Reporting Methodology" section for more information.

Net Peak Demand Savings (MW): peak demand savings attributable to conservation and demand management activities net of free-riders, etc. Please refer to the webinars in the "Reporting Methodology" section for more information.

Program-to-Date: the reporting period from January 1, 2011 until the end of the Current Reporting Period.

Program: a group of initiatives that target a particular market sector (i.e. Consumer, Industrial).

Reported or Unverified Savings: savings achieved that are based on reported activity and forecasted or best available savings assumptions. These savings are not verified, i.e. have not undergone the Evaluation, Measurement & Verification processes.

Unit: for a specific initiative, the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).

Reporting Methodology (Quarterly, Unverified results):

There are several resources on reporting that are available to LDCs:

- Reporting Policy & FAQ Document found on the iCON Portal in the "Other Program Materials" under "Reporting Tools"
- LDC Consumer Program Tracking Tool found on the iCON Portal in "Other Program Materials" under "Reporting Tools"
- Webinars (available at the following link: http://www.snwebcastcenter.com/custom_events/opa-20111781/site/index.php)
  - Understanding your Q4 2011 Report (April 11, 2012)
  - Tools from the Reporting WG (April 25, 2012)
  - A Deeper Look at: peaksaverPLUS® (May 23, 2012)
  - A Deeper Look at: Demand Response 3 (June 6, 2012)
  - Revisiting Reporting (June 20, 2012)
  - Quarterly CDM Status Report update (October 24, 2012) http://powerauthority.webex.com; password: DCx2012

3.0-VECC-18

Reference: E3/T1/S2/pg.10-11

a) Please confirm that Horizon is not making any adjustments to its 2015-2019 load forecast for CDM programs that may be initiated in 2015-2019. If any such adjustments are made, please set out what they are.

b) Please confirm that Table 3-6 shows the persistence of the savings assumed to be achieved from 2014 CDM programs over the subsequent years 2015-2019.

c) If the assumption stated in part (b) is incorrect, please explain what the values shown for the years 2015-2019 represent and how they were determined.

d) Please complete the following table based on the CDM assumptions used for the 2015-2019 load forecast:

	Forecast Year – Total CDM Savings Assumed					
CDM Program Year	2014	2015	2016	2017	2018	2019
2014						
2015	-					
2016	-	-				
2017	-	-	-			
2018	-	-	-	-		
2019	-	-	-	-	-	
Total						

Response:

a) Horizon Utilities is making adjustments to its 2015-2019 load forecast for CDM programs that may be initiated in 2015-2019 as provided in Table 3-6 in Exhibit 3, Tab 1, Schedule 2. At present, Horizon Utilities does not have a mandated CDM target for the 2015 to 2019 application period. Table 3-6 provides the estimated CDM savings for 2015 to 2019 based on historical program achievements, and the incremental impact of known CDM programs implement in each of those years. Subject to Horizon Utilities filing a new CDM plan with the Ontario Energy Board, there may be additional CDM programs initiated in the 2015 to 2019 application period.

b) Horizon Utilities shows the persistence of the savings assumed to be achieved from 2014 CDM programs over the subsequent years 2015 to 2019 in Table 3-7 of Exhibit 3, Tab 1, Schedule 2, Page 11.

c) Please refer to Horizon Utilities' response to part a) above.

d) Horizon Utilities has completed Table 1 below, based on the CDM assumptions used for the 2015-2019 load forecast.

Table 1: CDM Savings

	Forecast Year - Total CDM Savings Assumed					
CDM Program Year	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
2014 Bridge Year	7,035,500	28,142,000	28,142,000	28,142,000	28,142,000	28,142,000
2015 Test Year		3,710,968	19,534,205	19,534,205	19,534,205	19,534,205
2016 Test Year			3,968,422	19,205,046	19,205,046	19,205,046
2017 Test Year				3,909,634	19,129,390	19,129,390
2018 Test Year					3,909,634	19,129,390
2019 Test Year						3,909,634
Total	7,035,500	31,852,968	51,644,627	70,790,885	89,920,275	109,049,665

3.0-VECC-19

Reference: E3/T1/S2/pg.11-14

a) What is the basis for the Residential CDM adjustments used in Table 3-8 (i.e., the difference between the second and the fourth columns) for the years 2014-2019?

b) Please reconcile the CDM adjustments used in Table 3-8 for 2015-2019 with the CDM savings reported in Tables 3-6 and 3-7 for the same years.

c) With respect to page 13 (lines 7-8), how high does the Adjusted R-squared value need to be before it is "indicative of a good fit"?

d) With respect to page 13 (lines 11-12), what value does the T-Statistic have to be before it is considered to be "statistically significant"?

e) What does the explanatory variable "MA(1)" represent and why is a negative coefficient intuitively appropriate?

f) Please provide the data file that contains the determination of the actual regression equation and the calculation of the Residential forecast kWh for 2015-2019.

Response:

a) The basis for the Residential CDM adjustments used in Table 3-8 are Horizon Utilities' projections on CDM initiatives as reported in Table 3-6 in Exhibit 3, Tab 1, Schedule 2. Please refer to Horizon Utilities' response to part a) of 3-VECC-18 for further information.

b) Horizon Utilities has provided a table for the CDM adjustments used in Table 3-8 for 2014-2019 with the CDM savings reported in Tables 3-6 and 3-7 for the same years in Table 1 below. The difference between the second and fourth columns used in Table 3-8 are reflected in the column CDM Adjustment in Table 1 below. The column Table 3-6 represents the estimated annual CDM savings and the column Table 3-7 represents the estimated annual cumulative CDM savings as reported in Exhibit 3, Tab 1, Schedule 2. In order to derive a monthly impact for CDM from the annualized numbers in Table 3-6, Horizon Utilities allocated the CDM adjustment as portrayed in the CDM Adjustment column in Table 1.

Table 1: Residential (kWhs)

Residential	Unadjusted for CDM (kWh)	Adjusted for CDM (kWh)	CDM Adjustment	Table 3-6	Table 3-7
2014 Bridge Year	1,633,183,207	1,630,039,291	3,143,917	12,575,666	12,575,666
2015 Test Year	1,630,604,915	1,617,715,605	12,889,310	3,350,520	15,926,186
2016 Test Year	1,632,113,317	1,615,569,770	16,543,548	3,103,523	19,029,709
2017 Test Year	1,627,702,719	1,608,117,860	19,584,859	3,027,867	22,057,576
2018 Test Year	1,627,604,338	1,604,991,612	22,612,726	3,027,867	25,085,443
2019 Test Year	1,626,379,723	1,600,739,130	25,640,593	3,027,867	28,113,310

c) Horizon Utilities submits that there is no "correct" Adjusted R-Squared. The Adjusted R-Squared measures the amount of variation in monthly sales the specified model variables are able to explain. It is a relative measure that can be used to compare model specifications. Horizon Utilities objective is to estimate a model that provides a reasonable Adjusted R-Squared.

d) The T-Statistic tests whether the estimated variable coefficient is significantly different from zero. The larger the T-statistic, the higher the probability that the estimated coefficient is not zero and that the variable contributes to the explanation of the historical sales data. Similar to the Adjusted R-Squared, there is no specific right answer. Generally, Horizon Utilities would like to see model variables that are statistically significant at the 95% level of confidence (a T-Statistic close to 2), however, a variable with a T-Statistic of 1.6, for example, is still statistically significant at the 90% level of significant – that is there is a 90% probability that the variable coefficient is not equal to zero and contributes to the explanation of the sales data.

e) The MA(1) variable is used to correct for serial correlation. Serial correlation happens when the error in the current month is partly a result of the error in the prior month (or months). In the residential sales models the Durban-Watson statistics was close to 3 without correcting for serial correlation. Horizon Utilities' forecast models attempted to achieve a Durban-Watson around 2.

f) Please refer to Horizon Utilities' response to part a) of 3-EnergyProbe-17.

3.0-VECC-20

Reference: E3/T1/S2/pg.15-18

a) What is the basis for the GS<50 CDM adjustments used in Table 3-10 for the years 2014-2019?

b) Please reconcile the CDM adjustments used in Table 3-10 for 2015-2019 with the CDM savings reported in Tables 3-6 and 3-7 for the same years.

c) Please explain what the explanatory variable "mEcon.GDP Trend" represents and why a negative coefficient is intuitively appropriate.

d) Please provide the data file that contains the determination of the actual regression equation and the calculation of the GS<50 forecast kWh for 2015-2019.

Response:

a) The basis for the GS<50 kW CDM adjustments used in Table 3-10 are Horizon Utilities' projections on CDM initiatives as reported in Table 3-6 in Exhibit 3, Tab 1, Schedule 2. Please refer to Horizon Utilities' response to part a) of 3-VECC-18 for further information.

b) Horizon Utilities is providing a table for the CDM adjustments used in Table 3-10 for 2014-2019 with the CDM savings reported in Tables 3-6 and 3-7 for the same years in Table 1 below. The difference between the second and fourth columns used in Table 3-10 are reflected in the column CDM Adjustment in Table 1 below. The column Table 3-6 represents the estimated annual CDM savings and the column Table 3-7 represents the estimated annual cumulative CDM savings as reported in Exhibit 3, Tab 1, Schedule 2. In order to derive a monthly impact for CDM from the annualized numbers in Table 3-6, Horizon Utilities allocated the CDM adjustment as portrayed in the CDM Adjustment column in Table 1.

Table 1: GS < 50 kW (kWhs)

GS < 50 kW	Unadjusted for CDM (kWh)	Adjusted for CDM (kWh)	CDM Adjustment	Table 3-6	Table 3-7
2014 Bridge Year	590,199,426	589,101,097	1,098,329	4,393,315	4,393,315
2015 Test Year	590,445,253	586,002,830	4,442,422	928,649	5,321,964
2016 Test Year	591,143,528	585,648,636	5,494,892	846,487	6,168,451
2017 Test Year	589,487,741	583,142,939	6,344,802	846,487	7,014,938
2018 Test Year	588,749,906	581,558,617	7,191,289	846,487	7,861,425
2019 Test Year	587,936,814	579,899,038	8,037,776	846,487	8,707,912

c) Please refer to Horizon Utilities' response to part b) of 3-EnergyProbe-19.

d) Please refer to Horizon Utilities' response to part a) of 3-EnergyProbe-17.

3.0-VECC-21

Reference: E3/T1/S2/pg.18-22

a) What is the basis for the GS>50 CDM adjustments used in Table 3-12 for 2014-2019?

b) Please reconcile the CDM adjustments used in Table 3-12 with the CDM savings for 2015-2019 reported in Tables 3-6 and 3-7.

c) At page 21 the Application states that each of the T-statistics in the regression equation developed for the GS>50 class is statistically significant. Please reconcile this statement with the T-value reported for "mEcon.GDP Trend".

d) Please provide the data file that contains the determination of the actual regression equation and the calculation of the GS>50 forecast kWh for 2015-2019.

Response:

a) The basis for the GS > 50 kW CDM adjustments used in Table 3-12 are Horizon Utilities' projections on CDM initiatives as reported in Table 3-6 in Exhibit 3, Tab 1, Schedule 2. Please refer to Horizon Utilities' response to part a) of 3-VECC-18 for further information.

b) Horizon Utilities is providing a table for the CDM adjustments used in Table 3-12 for 2014-2019 with the CDM savings reported in Tables 3-6 and 3-7 for the same years in Table 1 below. The difference between the second and fourth columns used in Table 3-12 are reflected in the column CDM Adjustment in Table 1 below. The column Table 3-6 represents the estimated annual CDM savings and the column Table 3-7 represents the estimated annual cumulative CDM savings as reported in Exhibit 3, Tab 1, Schedule 2. In order to derive a monthly impact for CDM from the annualized numbers in Table 3-6, Horizon Utilities allocated the CDM adjustment as portrayed in the CDM Adjustment column in Table 1.

Table 1: GS > 50 kW (kWhs)

GS > 50 kW	Unadjusted for CDM (kWh)	Adjusted for CDM (kWh)	CDM Adjustment	Table 3-6	Table 3-7
2014 Bridge Year	1,865,094,324	1,862,301,069	2,793,255	11,173,019	11,173,019
2015 Test Year	1,872,385,651	1,857,864,416	14,521,236	15,255,036	26,428,055
2016 Test Year	1,882,436,649	1,852,830,462	29,606,188	15,255,036	41,683,091
2017 Test Year	1,886,034,069	1,841,172,846	44,861,224	15,255,036	56,938,127
2018 Test Year	1,892,041,498	1,831,925,238	60,116,260	15,255,036	72,193,163
2019 Test Year	1,897,968,467	1,822,597,172	75,371,296	15,255,036	87,448,199

c) The T-value for the GDP_Trend variable (an interaction of GDP and a linear trend variable) has a -1.9 t-statistic. This is statistically significant at close to the 95% level of confidence (there is less than 5% that the coefficient is equal to zero and thus the variable would be unimportant). The GS>50 kW sales model also includes GDP as a stand-alone variable. The T-Value for GDP in the specification is 1.57; this is statistically significant at close to the 90% level of confidence (there is only a 10% probability the coefficient should be zero). Both variables from a theoretical basis should be included in the estimated sales model as the interactive term allows the slope of the GDP variable to change over time capturing the structural change between electric sales and GDP.

d) Please refer to Horizon Utilities' response to part a) of 3-EP-17.

3.0-VECC-22

Reference: E3/T1/S2/pg.26-28

a) Please provide a schedule that sets out the kWh use per device for Street Lighting for the years 2008-2013 and the projected values for 2014-2019.

Response:

a) Horizon Utilities provides a schedule that sets out the kWh use per device for Street Lighting for the years 2008-2013 and the projected values for 2014-2019 in Table 1 below.

Table 1: Street Lighting kWh per device

	Street Lighting (kWh)	Devices	kWh/Device
2008 Actual	39,533,397	52,160	758
2009 Actual	39,460,322	52,250	755
2010 Actual	40,324,005	52,247	772
2011 Actual	39,350,326	52,170	754
2012 Actual	39,307,022	52,054	755
2013 Actual	39,480,566	52,447	753
2014 Bridge Year	39,744,804	52,412	758
2015 Test Year	39,694,810	52,384	758
2016 Test Year	39,602,538	52,356	756
2017 Test Year	39,651,553	52,328	758
2018 Test Year	39,629,670	52,300	758
2019 Test Year	39,610,413	52,273	758

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3.0-VECC-23

Reference: 3/T1/S2/pg.28-29

a) Please provide a schedule that sets out for 2008-2013:

i. The average kW of Standby Reserved annually.
ii. The amount of Standby Power provided annually.
iii. The amount of Standby Billed annually (i.e. which should be (i) – (ii) and equal to the values in Table 3-22)

b) How many standby customers did Horizon have in each customer class in each of the years 2008-2013?

Response:

a) i., ii., iii. The kW of standby reserved, standby provided (billed as load), and standby billed annually are provided in Table 1 below. Please note the process to bill load displacement generators from using the nameplate rating to billing them based on load displaced took place mid-2011. Prior to this standby power was based on the reserved capacity requested for both customers requesting load displacement as well as backup supply.

Table 1: Standby kWs

Year	Standby Resverved kW	Standby Provided kW	Standby Billed kW
2008 Actual	226,846	-	226,846
2009 Actual	236,007	-	236,007
2010 Actual	245,169	-	245,169
2011 Actual	292,494	38,164	254,330
2012 Actual	380,944	117,452	263,492
2013 Actual	411,273	138,620	272,653

b) Horizon Utilities provides the number of standby customers in each of the years 2008 to 2013 in Table 2 below.

Table 2: Standby Customers

	Standby Customers
2008 Actual	6
2009 Actual	6
2010 Actual	6
2011 Actual	6
2012 Actual	8
2013 Actual	8

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3.0-VECC-24

Reference: E3/T1/S2/pg.29-32

a) Why was the 2014 forecast for LU(1) and LU(2) set equivalent to 2013 use and not escalated by the forecast GDP rate of change for 2014?

b) For each of the LU(1) and LU (2) classes please provide a schedule that compares the year to date 2014 kWh usage with the usage in 2013 for the same period.

c) For purposes of forecasting 2015-2019 kWh usage was GDP-All Industries or GDP-Manufacturing used? Please explain the basis for the choice.

d) Did Horizon test whether past growth in LU(1) or LU(2) usage was correlated with GDP growth? If yes, what were the results? If not, please do so and provide the results.

Response:

a) Horizon Utilities set the 2014 kWh and kW forecast for the LU (1) and LU (2) customer classes the same as in 2013 because 2014 is only one year out and it was determined that the 2013 actuals would be a reasonable forecast for 2014 given the high confidence that there would be no changes to customer counts in these classes.

b) Table 1 and Table 2 below compare the year to date 2014 kWh usage with the usage in 2013 and the KW usage, respectively, for the same period (June) for LU (1) and LU (2).

Table 1: LU (1) & LU (2) kWh Usage

	Large Use (1) (kWh)	Large Use (2) (kWh)
2013 Actual (Jan - June)	131,783,084	164,965,978
2014 Actual (Jan - June)	129,943,154	171,951,127

Table 2: LU (1) & LU (2) kW Usage

	Large Use (1) (kW)	Large Use (2) (kW)
2013 Actual (Jan - June)	310,957	927,524
2014 Actual (Jan - June)	299,316	931,550

c) Horizon Utilities used GDP-All Industries for purposes of forecasting 2015-2019 kWh usage as this best represents the customers in the LU (1) and LU (2) rate classes.

d) Horizon Utilities had not performed a regression analysis prior to filing its Application on the LU (1) and LU (2) kWh usage using GDP as the only variable. Such regression was performed to respond to this interrogatory. Table 3 below shows the statistical results.

Table 3: Large Use Coefficients

Statistic:	Value
Adjusted R-Squared	-0.014
Mean Absolute Percentage Error (MAPE)	16.51%
Durbin-Watson Statistic	0.155

Variable:	Coefficient	Standard Error	T-Statistic	P-Value
CONST	52,097,549.04	57,525,182.77	0.91	36.82%
GDP.GDP	62.46	2,669.15	0.02	98.14%

3.0-VECC-25

Reference: E3/T2/S1/pg.1-2

a) How many Standby customers does Horizon forecast having in each year 2014-2019?

b) What accounted for the significant drop in number of Sentinel customers and connections in 2013?

c) Please explain why, for Sentinel and USL, the customer count is forecast to remain unchanged for 2014-2019 even though the number of connections is declining.

Response:

a) Horizon Utilities expects to maintain their existing eight Standby customers through the application period. Horizon Utilities has prepared for the possibility that customers in the LU (1) and LU (2) rate classes will request for standby service by applying for standby rates that are applicable to each of these classes in Exhibit 8.

b) Horizon Utilities revised the number of Sentinel Lighting connections after an internal data collection effort uncovered that internal reports did not update the number of Sentinel customers correctly. Horizon Utilities conducted the audit for the remaining customer classes and did not find any further discrepancies.

c) Horizon Utilities did not run a regression model on the customer count forecast for Sentinel and USL as this is not the determinant used to recover fixed distribution revenue. Horizon Utilities did however run a forecast using a simple linear trend function to extract the forecasted connections for the USL and Sentinel Lighting connections. Horizon Utilities has performed a reasonableness check, given the expected loss of connections for the Unmetered Scattered Loads class is on average 8 connections per year, and the Sentinel Lighting connections is expected to decrease by 6 connections on average per year.

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3.0-VECC-26

Reference: 3/T2/S1/pg.2-5

a) Please provide the customer count regression equations developed for the Residential, GS<50 and GS>50 classes including the associated regression statistics for each (e.g. similar to Table 3-9 done for Residential sales).

b) Please provide the actual customer count by class (including Standby) for the most recent month available.

Response:

a) Horizon Utilities provides the customer count regression statistics for the Residential, GS<50kW and GS>50kW classes in Tables 1 through 3 below. Horizon Utilities has provided the customer count regression equations developed for the Residential, GS<50kW and GS>50kW classes in its response to Energy Probe # 21.

Table 1: Residential Customer Forecast Model Statistics

Statistic:	Value
Adjusted R-Squared	0.997
Mean Absolute Percentage Error (MAPE)	0.06%
Durbin-Watson Statistic	1.691

Variable:	Coefficient	Standard Error	T-Statistic	P-Value
Constant	31,241.26	7,965.12	3.92	0.02%
Economics.Pop	291.38	12.76	22.84	0.00%
AR(1)	0.88	0.05	19.10	0.00%

Table 2: GS<50kW Customer Forecast Model Statistics

Statistic:	Value
Adjusted R-Squared	0.946
Mean Absolute Percentage Error (MAPE)	0.11%
Durbin-Watson Statistic	2.293

Variable:	Coefficient	Standard Error	T-Statistic	P-Value
CONST	9,666.91	2,064.51	4.68	0.00%
ResCust.Predicted	0.04	0.01	4.07	0.01%
mBin.AftSep11	107.86	30.47	3.54	0.07%
AR(1)	0.81	0.06	12.77	0.00%

Table 3: GS>50kW Customer Forecast Model Statistics

Statistic:	Value			
Adjusted R-Squared	0.869			
Mean Absolute Percentage Error (MAPE)	0.55%			
Durbin-Watson Statistic	1.548			
Variable:	**Coefficient**	**Standard Error**	**T-Statistic**	**P-Value**
mBin.AftSep11	(128.86)	17.72	(7.27)	0.00%
mEcon.Emp_Idx	2,215.87	18.35	120.78	0.00%
AR(1)	0.86	0.06	15.25	0.00%

b) Horizon Utilities has provided the June 2014 customer count by class in Table 4 below.

Table 4: Customer Count by class for June 2014

Customer Class	Customer Count
Residential	218,327
GS < 50 kW	18,442
GS > 50 kW	2,061
LU (1)	7
LU (2)	4
USL	1,859
Sentinel Lighting	207
Street Lighting	4
Standby	8
TOTAL	240,919

3.0-VECC-27

Reference: E3/T2/S1/pg.5-9

a) Using the HDD and CDD coefficients from Table 3-9 and the difference between the actual and weather normal degree days for each year 2010-2013, please estimate the weather normalized Residential use for each year and the resulting weather normal average use per customer.

b) Please confirm that in Figures 3-6, 3-8 and 3-9 the values show for 2014 are forecast and not actual values.

c) Please confirm that for the GS<50 and GS>50 classes average use per customer has been increasing since 2010 for those years where actual usage is available.

Response:

a) Horizon Utilities provides the weather normalized Residential use for each year and the resulting weather normal average use per customer for each year 2010-2013 in Table 1 below.

Table 1: Weather Normalized Residential (2010-2013)

	WN Residential kWh	Residential Customers	WN Average Use per Customer
2010 Actual	1,675,034,597	213,476	7,846
2011 Actual	1,598,604,299	214,865	7,440
2012 Actual	1,665,221,896	215,998	7,709
2013 Actual	1,602,479,268	217,557	7,366

b) Horizon Utilities confirms that in Figures 3-6, 3-8 and 3-9 the values show for 2014 are forecast and not actual values.

c) Horizon Utilities confirms that average use per customer for the GS<50kW and GS>50kW classes has been increasing since 2010 for those years where actual usage is available.

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3.0-VECC-28

Reference: 3/T3/S1

a) Please explain why the Miscellaneous Service Revenues (Acct #4235) decreased in 2013 as compared to 2012.

b) What is the basis for the 2015-2019 forecast for the Miscellaneous Service Revenues (Acct #4235)?

c) Please explain the significant increase in Rent from Electric Property (Acct. #4210) in 2013 and why this higher level is not forecast to continue for 2015-2019.

d) Please explain why there is no Interest and Dividend Income (Acct. #4405) reported for 2015-2019 when there are actual values shown for 2011-2013.

Response:

a) Miscellaneous Service Revenues (Acct #4235) decreased in 2013 compared to 2012 primarily as a result of lower recovery from thefts of power, lower connection charges, and lower reconnection charges.

b) Miscellaneous Service Revenue is primarily driven by customer requests and activities that are typically consistent year over year. The forecast of Miscellaneous Service Revenues for 2015-2019 is modelled based on the historical average of the last 30 months before budget preparation, adjusted for non-recurring factors from this period and modified for business changes (including levels of customer connections and disconnections) in the future that will impact these revenues significantly.

c) Please refer to Horizon Utilities' response to Interrogatory 3-EP-23 c) for the explanation of the increase in Rent from Electric Property in 2013 and why this level is not forecast to continue for 2014 to 2019.

d) Please refer to Horizon Utilities' response to Interrogatory 3-Staff-25 for an explanation of the Interest and Dividend Income forecast for 2015 to 2019.

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4.0-VECC-29

Reference: E4/T2/S1/pg.2

a) Please restate Table 4-8 to show 2011 MIFRS without smart meters.

Response:

a) Please see the table below which states 2011 MIFRS without Smart Meters:

Table 1: 2011 MIFRS Excluding Smart Meters

	2011 Actual Restated Without Smart Meters (MIFRS)
Operations	$ 23,396,603
Maintenance	4,222,626
Billing & Collecting	8,307,921
Community Relations	0
Administrative & General	13,148,552
Total	**$ 49,075,703**
Property taxes not included in OM&A	396,097
Donations (inclusive of LEAP)	138,308
Total including Property taxes and LEAP Donations	**$ 49,610,108**

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4.2-VECC-30

Reference: E4/T2/S2

a) Please explain the $100,000 in 2015/2018 for collective bargaining.

Response:

a) Horizon Utilities has forecast $100,000 in costs for collective bargaining in 2015 and 2018 including $50,000 for meeting rooms and equipment, meals, parking, mileage, training for management and union negotiating committees, legal/consulting, and printing new collective agreements. In addition, an amount of $50,000 was budgeted for contingency planning related to a potential labour disruption.

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4.2-VECC-31

Reference: E4/T2/S2/pg.32

a) Please provide separately the corporate communication and stakeholder/public relations costs for Horizon for the years 2009 through 2019.

b) Horizon states that since 2011 it has sought to have HHI provide these services. Please show the reduction in costs and FTEs that has occurred at Horizon since the transfer of these responsibilities.

Response:

a) Horizon Utilities has not tracked stakeholder/public relations costs separately from Corporate Communications. In Exhibit 4, Tab 3, Schedule 3, Table 4-29 on page 18 presents the total costs for Corporate Communications from 2011 to 2019. These costs were $814,897 and $725,103 for 2009 and 2010, respectively.

b) By way of clarification, HHI has assumed oversight responsibility for Corporate Communications; the department itself remains part of Electricity Distribution Operations ("EDO") within Horizon Utilities. Up to and including most of 2011, oversight of this function was included in the responsibilities of the Vice President, Corporate Services of Horizon Utilities. In Exhibit 4, Tab 3, Schedule 3, Table 4-28 on page 11 states that the costs for Corporate Services have declined from $592,461 in 2011 to $483,350 in 2014, a decrease of $109,111 which offsets in part the new management fee introduced in 2014 for services provided by HHI to EDO.

There has been no change in FTEs associated with the transfer of oversight responsibilities for Corporate Communications to HHI.

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4.2-VECC-32

Reference: E4/T2/S2

a) What is the basis for the increases in overtime in the 2015 through 2019 rate period?

Response:

Table 4-13 in Exhibit 4, Tab 2, Schedule 2, page 5, reproduced below, shows overtime at line 7 in the table for the years 2012-2019. The total increase in overtime in the 2015 through 2019 rate year is approximately 2% average per year over the term of the rate plan. There is no change in planned overtime hours for the duration of the 2015 to 2019 rate period and increases are a factor of expected wage and salary inflation offset by slightly lower increases in Construction & Maintenance ("C&M") planned overtime due to expected planning and scheduling benefits. The rate of increase is lower in 2015 and 2016 due to planned retirements in C&M during that period.

Table 4-13 – Chapter 2 Filing Requirement Appendix 2-JB - Recoverable OM&A Cost Driver Table: Salaries, Wages, and Benefits 2012 – 2019

Salaries, Wages and Benefits	2012 Actual	2013 Actual	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year	2011 Actual to 2015 Test Year	2015 Test Year to 2019 Test Year
Opening Balance*	**$ 27,751,037**	**$ 27,873,703**	**$ 29,763,913**	**$ 32,327,066**	**$ 33,445,459**	**$ 34,840,031**	**$ 35,844,178**	**$ 36,894,949**	**$ 27,751,037**	**$ 33,445,459**
Base Salaries and Wages (1)	$ 1,290,594	$ 1,524,115	$ 1,735,980	$ 483,291	$ 677,695	$ 798,021	$ 896,386	$ 923,333	$ 5,033,980	$ 3,295,435
OMERS (1)	$ 566,201	$ 455,446	$ 350,957	$ 54,422	$ 82,788	$ 97,170	$ 108,071	$ 111,098	$ 1,427,026	$ 399,127
CPP, EI, EHT, WSIB (1)	$ 91,560	$ 254,218	$ (5,395)	$ 16,007	$ 49,808	$ 58,519	$ 74,308	$ 71,110	$ 356,391	$ 253,745
Incentive Pay (1)	$ 14,075	$ 115,586	$ 62,229	$ 38,524	$ 39,592	$ 40,710	$ 41,851	$ 43,020	$ 230,415	$ 165,173
Overtime & Vac/OT Payouts (1)	$ (546,509)	$ 757,160	$ (683,785)	$ 10,364	$ 12,972	$ 35,289	$ 49,178	$ 65,503	$ (462,771)	$ 162,942
Post-employment benefits (1)	$ 373,541	$ 18,825	$ 28,057	$ 38,832	$ 41,970	$ 45,558	$ 48,697	$ -	$ 459,255	$ 136,225
Life, Health, LTD (1)	$ (371,539)	$ (491,749)	$ 947,620	$ 16,182	$ 60,863	$ 149,210	$ 80,478	$ 84,841	$ 100,514	$ 375,392
Contract Labour (1)	$ 38,348	$ (11,027)	$ 123,405	$ (25,456)	$ -	$ -	$ -	$ -	$ 125,270	$ -
Other employee compensation (1)	$ (27,343)	$ (63,752)	$ 55,875	$ (154)	$ 935	$ 983	$ 1,330	$ 1,347	$ (35,373)	$ 4,595
Net Labour Allocation	$ (1,306,262)	$ (668,613)	$ (51,789)	$ 486,380	$ 427,950	$ (221,312)	$ (249,528)	$ (325,382)	$ (1,540,285)	$ (368,273)
Closing Balance	**$ 27,873,703**	**$ 29,763,913**	**$ 32,327,066**	**$ 33,445,459**	**$ 34,840,031**	**$ 35,844,178**	**$ 36,894,949**	**$ 37,869,820**	**$ 33,445,459**	**$ 37,869,820**
Increase to payroll costs (sum of (1) above)	*$ 1,428,928*	*$ 2,558,823*	*$ 2,614,942*	*$ 632,013*	*$ 966,623*	*$ 1,225,459*	*$ 1,300,299*	*$ 1,300,254*	*$ 7,234,707*	*$ 4,792,635*
Net change in labour allocation to OM&A	*$ (1,306,262)*	*$ (668,613)*	*$ (51,789)*	*$ 486,380*	*$ 427,950*	*$ (221,312)*	*$ (249,528)*	*$ (325,382)*	*$ (1,540,285)*	*$ (368,273)*
Net increase to OM&A	***$ 122,666***	***$ 1,890,210***	***$ 2,563,153***	***$ 1,118,393***	***$ 1,394,572***	***$ 1,004,147***	***$ 1,050,771***	***$ 974,872***	***$ 5,694,422***	***$ 4,424,362***

** Opening 2012 Actuals represent 2011 Actual costs, as restated to Modified IFRS and to include Smart Meter costs*

4.2-VECC-33

Reference: E4/T2/S2

a) Please provide details as to the $427,950 in labour costs that are initially capitalized and subsequent to 2010 expensed. Specifically how many FTEs are involved and are all permanent staff of Horizon?

Response:

a) The reference to $427,950 from Table 4-13 represents the increase in labour allocated to OM&A in 2016, as compared to the 2015. This amount represents the equivalent of approximately four FTEs, all of whom are permanent employees of Horizon Utilities. The increase is mainly due to IST staff who are expected to be working on the ERP Upgrade capital project in 2015 and are reverting to operational roles in 2016.

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4.2-VECC-34

Reference: E4/T2/S2

a) Please provide the amounts budgeted for storm damage for each of the years 2014 through 2019. Please explain how the amount is derived.

b) Please provide the amount spent on storm damage repairs for 2009 through 2013. Please explain what qualifies as storm damage as opposed to maintenance.

Response:

a) Given the reference provided, Horizon Utilities assumes the question regarding costs refers to OM&A costs only, not Capital costs. Table 1 below shows Horizon Utilities' forecast OM&A costs for severe storms. They are based on Horizon Utilities' anticipation that will be three or more severe storm events on average for each year over the 2014-2019 period. Only three severe storm events per year are reflected in the derivation of the forecast costs in Table 1. Based on recent experience, the assumed cost per severe storm event will be about $400,000 (in 2014 constant dollars).

Table 1: OM&A Costs budgeted for severe storm events

	2014	**2015**	**2016**	**2017**	**2018**	**2019**
OM&A ($)	1,250,000	1,290,000	1,330,000	1,370,000	1,410,000	1,450,000

Only costs associated with severe storms have been tracked and budgeted separately. There are other storm-related costs for non-severe storms that occur throughout the year but those costs are embedded in total reactive maintenance costs; they are not tracked and budgeted separately.

b) The OM&A costs associated with severe storms in 2011, 2012, and 2013 are presented in Table 4-40 in Exhibit 4, Tab 3, Schedule 3, page 64. For ease of reference they are reproduced in Table 2 below. Costs for the years 2009 and 2010 were not tracked in this manner and therefore are not reported in the table below.

Table 2: Historical Severe Storm Costs

Year	Severe Storm Event	Severe Storm OM&A ($)
2009	-	-
2010	-	-
2011	April 2011	488,224
2012	July 2012	400,000
2012	October 2012	133,277
2013	July 2013	471,824
2013	December 2013	432,444

Severe storms are considered those that require all available maintenance crews, including activation of Horizon Utilities' Emergency Operations Center to coordinate corporate-wide activities, around the clock for a number of days.

4.2-VECC-35

Reference:

a) Please explain what steps Horizon is taking to reduce labour costs.

Response:

Horizon Utilities is taking a number of steps to manage labour costs. Horizon Utilities has achieved significant labour savings through a number of initiatives which can be categorized into three main areas: operating expenditure reductions, increase in capacity/productivity and future cost avoidance.

The creation of worker capacity within the organization is necessary to meet new and emerging priorities while containing costs in the delivery of services to customers. Productivity initiatives and efficiency improvements that enable Horizon Utilities to manage and offset labour costs while maintaining and enhancing overall customer service are detailed in Exhibit 4, Tab 3, Schedule 4. More specifically, centralized work planning and scheduling (Exhibit 4, Tab 3, Schedule 4 p.20), the implementation of a paperless work management system (e-mobile) (Exhibit 4, Tab 3, Schedule 4 p.8 - 11), automation of manual processes (Exhibit 4, Tab 3, Schedule 4 p.10,38,), and strategic and overflow outsourcing (Exhibit 4, Tab 3, Schedule 4 p.11, 22)) have resulted in overtime and FTE reductions, as well as reducing the number of future hires by increasing organizational capacity. As provided in Exhibit 4, Tab 4, Schedule 2, p. 8, Horizon Utilities' rate plan includes a reduction of 10.2 FTE by 2019.

In addition to productivity initiatives and efficiency improvements, Horizon Utilities' workforce planning process provides for a prudent review and evaluation of resources to meet business requirements and considers opportunities for consolidation of work, reallocation of positions to more value-added roles, and position elimination or outsourcing. Further opportunities to manage labour costs will be explored during the 2015 collective agreement renewal process. Please refer to Horizon Utilities' response to Interrogatory BOMA 8 a) for further detail regarding Horizon Utilities' productivity initiatives.

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4.2-VECC-36

Reference: E4/T2/S3/pg.2/Table 4-20

a) Please provide the OM&A cost per customer and OM&A cost per FTE for 2011 on a CGAAP basis

Response:

a) Table 4-20 of Exhibit 4, Tab 2, Schedule 3, provided the 2011 OM&A cost per customer and OM&A cost per FTE on a CGAAP basis. However, the number of customers for 2011, 2012 and 2013 Actual were incorrectly stated in Table 4-20 of the Application, and a revision to the table is provided below, in Table 4-20.1. Please also see Horizon Utilities' response to 4-Energy Probe-24 (a).

Table 4-20.1 OM&A per Customer and per FTE 2011 – 2019 (with correction to Number of Customers)

	Last Rebasing Year -2011- Board Approved	Last Rebasing Year - 2011- Actual	2012 Actual	2013 Actual	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Number of Customers	237,031	237,305	238,488	240,114	241,692	243,319	245,123	247,036	249,021	250,909
Total Recoverable OM&A from Appendix 2-JB	$ 42,136,201	$ 41,644,654	$ 51,478,365	$ 54,516,506	$ 60,387,369	$ 62,632,679	$ 64,394,131	$ 66,255,827	$ 67,708,658	$ 69,140,489
OM&A cost per customer	$ 177.77	$ 175.49	$ 215.85	$ 227.04	$ 249.85	$ 257.41	$ 262.70	$ 268.20	$ 271.90	$ 275.56
Number of FTEs	349	328	333	335	355	348	345	344	344	344
Customers/FTEs	679	724	717	717	682	700	711	718	723	729
OM&A Cost per FTE	$ 120,699.52	$ 127,058.38	$ 154,729.08	$ 162,735.84	$ 170,340.38	$ 180,103.17	$ 186,649.65	$ 192,458.68	$ 196,678.84	$ 200,838.00

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4.2-VECC-37

Reference E4/T2/S2/pg.32 & E4/T3/S2/pgs.2-6

a) Please provide the total amount paid for customer care services for each years 2009 through 2019.

b) Please provide the total cost of HHI's customer care operations.

c) Horizon states that it contracts for these services expires as of the end of 2014. Please explain what due diligence Horizon is undertaking to ensure it will purchase the required services at a competitive price. Specifically please indicate if Horizon will be tendering for this service and if not why not.

Response:

a) The following table shows, for each year requested, (i) the amount charged by Customer Care ("CC") to Electricity Distribution Operations ("EDO") for customer care services; (ii) the amount charged by EDO to CC for shared corporate services; and (iii) the difference between the two, as the net amount payable by EDO to CC:

Table 1: Fees Charged 2009 - 2019

Year	Fee charged by CC to EDO	Fee charged by EDO to CC	Net Payable by EDO to CC
2009	6,790,000	583,000	6,207,000
2010	6,710,000	583,000	6,127,000
2011	6,612,128	600,490	6,011,638
2012	7,299,834	612,500	6,687,334
2013	7,356,864	624,750	6,732,114
2014	8,070,878	1,011,570	7,059,308
2015	8,337,068	1,049,001	7,288,067
2016	8,549,087	1,082,146	7,466,942
2017	9,081,711	1,108,693	7,973,018
2018	9,012,779	1,143,978	7,868,801
2019	9,144,631	1,156,582	7,988,050

b) The following table shows, for each year 2009 through 2019, the total operating costs of Customer Care (including the fee charged by EDO). These costs are inclusive of all costs incurred to provide the City of Hamilton and EDO with the services enumerated on page 32 of Exhibit 4, Tab 2, Schedule 2. Note that these costs are incurred within Horizon Utilities Corporation, not HHI.

Table 2: Customer Care Operating Costs

Year	Total CC Operating Costs
2009	9,490,000
2010	9,736,000
2011	9,878,000
2012	10,232,000
2013	10,338,000
2014	11,398,273
2015	11,738,182
2016	12,051,537
2017	12,424,524
2018	12,602,103
2019	12,679,063

c) Page 32 of Exhibit 4, Tab 2, Schedule 2 states that Horizon Utilities, through its Customer Care division, provides water billing services to the City of Hamilton under a contract which expires December 31, 2014. It is the City of Hamilton that will tender for these services, not Horizon Utilities. Horizon Utilities does not purchase any services under that contract.

4.2-VECC-38

Reference: E4/T3/S2/pg.9

a) Will Horizon have any manual meter reading costs post 2014 reading costs and after is anticipates installing the remaining smart meters?

Response:

a) Horizon Utilities will have manual meter reading expenditures post 2014. As identified on page 8 of Exhibit 4, Tab 3, Schedule 2, Horizon Utilities intends to transition all conventional meters to Smart Meters by the end of 2015 and will have expenditures related to conventional meter reading until the conversion is complete. A small number of hard-to-reach ("HTR") meter locations are anticipated to remain unconverted beyond 2015 due to lack of access to the meter or other restriction, for which manual meter reading will continue to be required. Horizon Utilities anticipates less than 150 HTR meter locations will remain beyond 2015.

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4.2-VECC-39

Reference: E4/T3/S2/pg.11

a) Please provide the actual bad debt (credit loss) for 2007 through 2013. Please provide the calculation (including economic projects, customer growth etc.) that Horizon used to calculate bad debt costs for 2016-2019.

Response:

Credit losses are calculated as: gross credit losses; less recovery of past credit losses; and changes in the allowance for doubtful accounts. Horizon Utilities has provided the actual credit losses for 2007 through 2013 in the table below.

Table 1: Credit Losses

Credit Losses	2007	2008	2009	2010	2011	2012	2013
Gross receivable write-offs	$ 1,924,865	$ 1,694,643	$ 1,879,630	$ 1,882,102	$ 2,086,225	$ 2,292,674	$ 2,134,230
Less: recovery of receivables previously written off	754,437	715,946	716,365	829,869	760,094	930,098	961,444
Change in allowance for doubtful accounts	-	-	150,000	400,000	200,000	150,000	(150,000)
Net credit loss	$ 1,170,428	$ 978,697	$ 1,313,265	$ 1,452,233	$ 1,526,131	$ 1,512,576	$ 1,022,786

Forecasted bad debts costs for 2016 through 2019 were determined on the basis of: (i) estimated customer growth and corresponding distribution revenue by customer class; (ii) estimated increases in accounts receivable balances resulting from estimated customer growth; (iii) an analysis of historical gross credit losses, in comparison with the value and aging of actual accounts receivable balances; (iv) an analysis of actual recoveries of receivables previously written off, resulting in a recovery rate of approximately 40% for the years 2007 to 2013 inclusive; and (v) consideration of forecasted economic trends and potential impacts, if any, on larger customers.

The allowance for doubtful accounts is computed based on the sum of: i) all uncollected customer accounts beyond 90 days; ii) a specific provision for customer accounts identified as bad debts (e.g. customers in receivership or bankruptcy); and iii) general provision on the balance of outstanding accounts receivable. The general provision is principally based on: i) an analysis of historic trends of accounts receivable write-offs; and ii) the historic values of unbilled revenue that comprises a significant proportion of total accounts receivable balances. Historically, unbilled revenue accounts for approximately 50% to 66% of total accounts receivable balances. The determination of a general provision for unbilled revenue accounts receivable is the appropriate methodology as specific uncollectible unbilled revenue accounts receivable amounts cannot be determined. This methodology is consistent with the methodology filed in the 2011 Cost of Service Application (EB-2010-0131).

In addition, the general provision also incorporates the increase in the corporate credit risk profile due the new standardization codes implemented by the Ontario Energy Board in October 2010 and January 2011. These customer service code amendments include:

- Unbilled revenue is no longer secured by deposits from customers with a poor payment history;
- Security deposits must be applied to outstanding accounts receivable prior to issuing a disconnection for non-payment;
- Extension of the time periods to repay arrears under the Arrears Management Program to a period of between 8 and 16 months; and
- For customers who qualify for the Low Income Energy Assistance Program, deposits may be waived.

The allowance for doubtful accounts is monitored monthly and adjusted as appropriate through bad debts expense.

Horizon Utilities forecasts customer counts and consumption volumes to increase annually as identified in Table 3-29 of Exhibit 3, Tab 2, Schedule 1. The higher forecast amounts also anticipate higher bills that principally correspond to increases in: commodity prices; Hydro One transmission rates; and the elimination of the 10% Ontario Clean Energy Benefit.

4.2-VECC-40

Reference: E4/T3/S2/pg.12

a) Please provide further detail on Horizon's "Asset Management Program." Specifically address the cost of the program (to Horizon and the affected customer(s)) and how the program works in conjunction with the Board mandated LEAP program.

Response:

a) Horizon Utilities understands the question to be regarding the "Arrears Management Program" as provided in Exhibit 4, Tab 3, Schedule 2, page 11.

Horizon Utilities' Arrears Management Program ("AMP") is the mandatory provision of arrears payment agreements for eligible customers as mandated by the Ontario Energy Board in Section 2.7 of the Distribution System Code.

As of the end of 2013, Horizon Utilities had 564 customers with an active AMP arrangement with a Program total of approximately $211,000 in deferred arrears. The cost of the program to Horizon Utilities is primarily the credit risk related to the deferred arrears and the internal management of the program. In 2013, Horizon Utilities wrote-off approximately $516,000 of customer deferred arrears that were not collected related to the AMP program, net of any subsequent recoveries.

Horizon Utilities estimates the annual program cost of administration to be the equivalent of one FTE. The program has been implemented without increasing headcount as the capacity required has been realized as a result of productivity and capacity-building initiatives in Customer Service.

There are no direct service charges to the customer to participate in an AMP, although the customer must, as part of the program agreement, pay an initial down payment towards account arrears.

The AMP is offered to all residential customers. Qualifying residential customers also have access to financial assistance, payment terms and waiving of the security deposit requirement through the Board-mandated Low Energy Assistance Program ("LEAP"). Information regarding AMP and LEAP are available to customers on the Horizon Utilities website, on the back of bills and notices, as well as through conversations with Customer Service Representatives.

4.2-VECC-41

Reference: E4/T3/S3/pg.11

a) Please provide the annual total Human Resource costs as shown in Table 4-28 if the cost increase were limited to (1) Horizon's annual inflation assumption (please provide inflation assumptions) + (2) Horizon's assumed percentage annual increase in FTEs.

Response:

1) The following table provides annual total Human Resources costs if the cost increase was limited to Horizon Utilities' annual inflation rate. The annual inflation for 2012 and 2013 in the table below is based on actual cost increases for 2012 and 2013 as provided in Appendix 4, Tab 3, Schedule 3, Tables 4-22 to 4-25. As described in Appendix 4, Tab 2, Schedule 2, there are a number cost drivers that resulted in the increase in OM&A at Horizon Utilities. The assumed annual inflation rate is 1.5% for non-labour and [redacted] labour 2014. For each year from 2015 to 2019 the annual inflation assumption is 1.5% for non-labour and [redacted] for labour.

Human Resources and Healthy Workplace and Safety costs, including reallocated and additional FTE as identified in Exhibit 4, Tab 3, Schedule 3, p.12-17, have been key to meeting organizational and customer service objectives and delivering the enhanced Human Resources strategic plan.

Annual Expenditures									
	2011 Board - Approved	2012 Actual	2013 Actual	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Tear
Corporate Services	$ 399,506	$ 414,262	$ 438,711	$ 449,447	$ 459,897	$ 470,609	$ 481,587	$ 492,840	$ 504,375
Healthy Workplace & Safety	$ 462,808	$ 479,903	$ 508,225	$ 520,097	$ 531,691	$ 543,565	$ 555,726	$ 568,181	$ 580,939
Human Resources	$ 1,672,609	$ 1,734,390	$ 1,836,750	$ 1,880,697	$ 1,923,543	$ 1,967,443	$ 2,012,421	$ 2,058,508	$ 2,105,731
Total	**$ 2,534,923**	**$ 2,628,555**	**$ 2,783,686**	**$ 2,850,241**	**$ 2,915,132**	**$ 2,981,616**	**$ 3,049,734**	**$ 3,119,530**	**$ 3,191,046**

2) Not applicable. Horizon Utilities does not have an “assumed percentage annual increase in FTE”. Further, Horizon Utilities is not increasing FTE for the period 2015-2019.

4.2-VECC-42

Reference: E4/T3/S3/pg.21

a) Why is there an increase in regulatory costs during the rate period when presumably Horizon will be filing no/or limited number of applications?

Response:

a) The increase in regulatory costs during the rate period is mainly due to the recovery of one-time costs to prepare the 2015 Custom IR Application and wage inflation. All costs other costs remain stable throughout the rate period. Table 1 below provides a summary of the changes to Regulatory costs over the rate period:

Table 1: Regulatory Costs

Regulatory Affairs Costs	2014	2015	2016	2017	2018	2019
Salaries and Wages	$ 1,093,408	$ 1,181,643	$ 1,219,468	$ 1,260,107	$ 1,301,329	$ 1,391,296
Legal and consulting	$ 345,000	$ 300,000	$ 300,000	$ 300,000	$ 300,000	$ 300,000
OEB Assessments and costs	$ 700,000	$ 700,000	$ 700,000	$ 700,000	$ 700,000	$ 700,000
Operating expenses	$ 150,000	$ 150,000	$ 150,000	$ 150,000	$ 150,000	$ 150,000
Total Regulatory Affairs Department	**$ 2,288,408**	**$ 2,331,643**	**$ 2,369,468**	**$ 2,410,107**	**$ 2,451,329**	**$ 2,541,296**
Recovery of One-Time Costs to prepare the 2015 Customer IR Application		$ 551,941	$ 551,941	$ 551,941	$ 551,941	$ 551,941
Total Regulatory Affairs Budget per table 4-30	**$ 2,288,408**	**$ 2,883,584**	**$ 2,921,409**	**$ 2,962,048**	**$ 3,003,270**	**$ 3,093,237**

The Regulatory Affairs department is accountable for all aspects of regulatory processes for the organization including: regulatory filings; compliance; and related internal operational support. Regulatory builds and supports key relationships with government, regulators, industry peers, and stakeholders to strategically monitor, influence, and evaluate potential impacts and opportunities related to industry regulation.

The Regulatory Affairs department leads in developing and defending applications for electricity distribution rates, e.g., periodic Cost of Service applications and interim annual Incentive Rate Mechanism ("IRM") applications in prior years, annual updates and potentially reopeners in future year. Such applications determine the amount of revenue

Horizon Utilities may earn from its customers to: support necessary investments in and maintenance of its electricity distribution system; and deliver fair financial returns to its shareholders.

Regulatory Affairs is also responsible for preparing ad hoc applications, as may be required. In prior years such has included the Smart Meter Prudence Application and Service Area Amendment Applications.

Regulatory Affairs is also responsible for the following processes:

- Daily settlements with the sources of energy and customers;
- Forecasting and analyzing revenue based on a detailed, statistically based electricity load forecast for all customer classes;
- Monthly reporting and monitoring of regulatory balances such as the Deferral and Variance Accounts;
- Quarterly and annual OEB Reporting and Record Keeping (“RRR”) requirements; and
- Compliance with statues and codes including the protection of privacy. The Vice-President Regulatory Affairs is the Privacy Officer for the organization.

Regulatory Affairs advises executive management of the financial, economic, political, and operational implications of current and evolving regulation with due regard for corporate strategy and compliance. It monitors pending and existing regulatory activities that will affect growth opportunities.

Regulatory Affairs’ budget for regulatory costs is found in Exhibit 4, Tab 4, Schedule 6, Table 4-72 and recognizes the full complement of staff (8 plus a shared Executive Assistant). Budgeted cost adjustments through 2015-2019 incorporate inflationary adjustments to salaries and wages. remain flat. Payroll costs and the annualized costs of this application are recognized in the total budget amounts in Exhibit 4, Tab 3, Schedule 3, Table 4-30, page 21. In Exhibit 4, Tab 3, Schedule 3, Table 4-30 shows the difference in each year by dollars and by percentage. The increase year over year is

Exhibit 4, Tab 3, Schedule 3, pages 22 and 23. Costs for the 2020 Cost of Service Application have not been included in budget numbers.

The costs for 2015–2019 include an annual recovery of costs related to the 2015 Custom IR Application in the amount of $551,941 in each year.

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4.2-VECC-43

Reference: E4/T3/S3/pg.26

a) Please explain what "PC Services" entail and why the costs for this category of IT costs more than doubles over the term of the rate plan.

Response:

a) PC Services costs include all the activities of the Technical Services sub-department of the Horizon Utilities Information Systems and Technology department, as outlined in Exhibit 4, Tab 3, Schedule 2, page 40. These services include the implementation, monitoring, management, and user support for all Horizon Utilities IST infrastructures, including: servers; networks; telephony; data communications; mobile computing; and end-user computing environments.

As identified in Table 4-32 of Exhibit 4, Tab 3, Schedule 3, Page 26, over the 2014 to 2019 term of this Application, PC Services costs are increasing by $364,783 from $1,712,577 to $2,077,360, a compound annual increase of 3.9%.

These cost increases are driven primarily by the following expenditures:

- An increase in Salaries and Benefits of $107,939, or a 2.89% compound annual growth rate;
- An increase in Computer Maintenance of $137,046 or 10.4% compound annual growth rate for incremental hardware infrastructure and servers to support the following: new applications implementations (such as: GIS/OMS, Enterprise Unified Communications); annual data storage requirements increasing in excess of 30% from incremental data collected by applications; and, corresponding incremental backup capacity to support data growth; and
- An increase in Software License and Maintenance costs of $79,909 or 4.2% compound annual growth rate for incremental software corresponding to new servers to support new applications and annual growth of the infrastructure identified above.

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4.2-VECC-44

Reference: E4/

For each of the years 2010 through 2014 please provide:

a) EDA membership fees
b) All other corporate membership fees
c) Please confirm that EDA fees are included in the annual prepaid category of the Lead-Lag Study

Response:

a) Table 1 below provides the schedule for EDA membership fees:

Table 1 – EDA Fees

Description	2010 Actuals	2011 Actuals	2012 Actuals	2013 Actuals	2014 Forecast
EDA membership fees	$ 97,900	$ 93,254	$ 106,500	$ 111,500	$ 116,400

b) Table 2 below provides the schedule for all other corporate membership fees:

Table 2 – Corporate Fees

Description	2010 Actuals	2011 Actuals	2012 Actuals	2013 Actuals	2014 Forecast
Canadian Electricity Assocation	$ 38,395	$ 44,870	$ 38,395	$ 53,487	$ 50,929
Ontario Energy Association	$ 30,000	$ 30,000	$ 27,500	$ 30,000	$ 25,000

c) In Exhibit 2, Tab 4, Schedule 1, page 1 states "OM&A expense categories with a total expenditure of less than $500,000 aggregated to $4,200,000, were deemed immaterial in the determination of the Working Capital Allowance percentage". Membership fees were below this threshold and therefore excluded from the Lead-Lag Study.

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4.2-VECC-45

Reference: E4/

a) Please provide all training and conference costs for the 2011-2019 period broken down into the following categories

i. Training – operations/maintenance
ii. Training – other
iii. Conferences

Response:

Part i) and ii). Horizon Utilities' training costs for the period 2011-2019 are summarized in the following tables:

Table 1: Training Costs 2011 - 2014

Description	2011 Actuals	2012 Actuals	2013 Actuals	2014 Bridge Year
Training – operations/maintenance	411,886	381,923	258,960	369,685
Training – other	278,720	258,023	267,662	337,815
Total	**690,606**	**639,947**	**526,621**	**707,500**

Table 2: Training Costs 2015 - 2019

Description	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Training – operations/maintenance	385,380	396,743	397,112	403,068	398,964
Training – other	342,882	348,026	353,246	358,545	363,923
Total	**728,262**	**744,769**	**750,358**	**761,613**	**762,887**

Part iii) Horizon Utilities does not track conferences as a separate training cost.

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5.0-VECC-46

Reference: E5/T1

a) Is it Horizon's proposal that the annual Cost of Capital adjustment be calculated based on actual rate base or the deemed rate base arising out of the Board's approval of a 5 year plan?

b) If the former than please explain what regulatory process is anticipated for consideration of any over or under spending (higher or lower rate base than anticipated) during the rate plan.

Response:

a) Horizon Utilities is proposing that the annual Cost of Capital adjustment be calculated based on the deemed rate base included in the Application.

b) Not applicable. Horizon Utilities is not proposing that the annual Cost of Capital adjustment be calculated on actual rate base.

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5.0-VECC-47

Reference: E5/T1/S3

a) Horizon states that it anticipates issuing new long-term debt within the 2015-2019 rate period. Given that it is proposing a five year capital plan and interest rates are at historically low rates, why is the Utility not issuing debt in the immediate or near future?

b) Has Horizon investigated private market debt placement or borrowings? If so what were the results?

Response:

a) Please refer to 5-EP-46.

b) The issued long-term debt of Horizon Utilities (refer to Table 5-13) ("Horizon Debt") is provided by its parent, Horizon Holdings Inc. ("HHI"). HHI provides the Horizon Debt through back-to-back issuances of debentures under a Trust Indenture dated July 21, 2010 ("HHI Debentures").

The HHI Debentures are issued privately but using an agency arrangement whereby the agent uses its best efforts to provide for the purchase of the debentures. The process used by HHI is effectively the same as that used by large public issuers such as Hydro One and Toronto Hydro, other than such issuers actually issue to the public at large. Additionally, the terms and covenants underlying the HHI Debentures are substantially the same as large comparable public issuers such as those identified above.

Consequently, Horizon Utilities effectively issues debt on a private placement basis through HHI but using a process similar to public issuance of debt.

The results of issuance are competitive and market based and, more specifically, as provided in Table 5-13.

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6.0-VECC-48

Reference: E6/T2/S1/pgs. 20-22

a) Horizon has a discussion with respect to issue of IFRS accounting changes on PILs and the accounting rates of return. Does Horizon have a preferred solution to the issues it raises? If so please explain.

Response:

a) This is a complex issue that requires some context in order to identify possible options for a solution. Horizon Utilities identified this issue in its Application create awareness of potential implications further summarized below. Horizon Utilities would be pleased to work further with the Board on this matter.

The transition to IFRS has exacerbated (but did not create) an issue that arose at the time the Board was resolving its approach for the recovery of PILs in rates. At that time and as part of the Board stakeholdering of this issue, the former Hamilton Hydro (continuing in Horizon Utilities) suggested to Board Staff that it consider determining the PILs Proxy on an accounting basis rather than a cash taxes basis to recognize the value of future tax assets and liabilities in rates.

Consider that, with the exception of PILs, all elements embedded in Revenue Requirement (other than perhaps the Working Capital Allowance) are determined on an accounting basis with reference to regulatory accounts; which basis can diverge from a cash basis. With respect to these accounting-based elements, there is clarity and transparency regarding the value and timing of their recovery in rates.

However, rate-making principles provide for the recovery of PILs on a cash basis. Consequently, PILs, net income, and returns on equity for accounting purposes will not align to the same for regulatory purposes. The differences are only of a timing nature, but, with respect to utility assets, such timing differences reverse over a very long period. These timing differences represent future tax obligations or recoveries principally as a result of historical investments in fixed assets. Horizon Utilities submits that there may not be adequate transparency to customers on the nature or magnitude of these future tax assets or liabilities including when such will be credited to or, more likely, be recovered from customers.

Consider that future tax liabilities arising in a fiscal year represent a future customer obligation under the current methodology for the recovery of PILs. Conversely, future tax assets arising in a fiscal year represent a future settlement obligation to a customer under the same. Customers are likely to favour an approach that requires them to compensate cash PILs when such are less than accounting-based PILs (which is the present circumstance of Horizon Utilities in this Application). Horizon Utilities questions whether the reverse will be true when such timing differences reverse and it appears that customers are compensating cash PILs well in excess of accounting-based PILs.

The most material example contributing to this issue corresponds to differences in the treatment of fixed assets for PILs and accounting purposes. The Revenue Requirement recovers depreciation on fixed assets; not capital cost allowance ("CCA"). Depreciation and CCA can and often do differ materially in terms of the timing of amortization of fixed assets. Rate-making principles choose to use CCA as the basis of a deduction for PILs recovery purposes rather than depreciation. This internal inconsistency within rate-making methodology, adjusting accounting based revenues and deductions to tax based revenues and deductions for purposes of computing a cash-based PILs recovery, results in the PILs, income and return on equity inconsistency described above.

The response to 1-BOMA-7b) with reference to 1-BOMA-7 Table 2 demonstrates this phenomenon with respect to the single largest asset class of distributors: Distribution Plant assets. Such assets are amortized for accounting purposes over a very long period; generally in excess of forty (40) years or at most 2.5% per year on a straight-line basis. However, the corresponding CCA rate for these Class 47 assets is 8%. 1-BOMA-7b) demonstrates that the excess of CCA over accounting depreciation in the first 5 years (this trend will continue for many years) actually results in PILs Income losses and a corresponding recovery of PILs (rather than a payment) with respect to new additions.

The analysis in 1-BOMA-7 Table 2 has been modified in the following tables: 6-VECC-48 Table 1 and 6-VECC-48 Table 2.

Table 1: response to 6-VECC-48

HORIZON UTILITIES CORPORATION					6-VECC-48 Table 1	
Response to 6-VECC-48						
($000s)						
Assumptions:						
2015 CapEx	10,000					
Depreciable Life (Years)	40					
CCA Rate	8.00%					
PILs Rate	26.25%					
Deemed Debt %	60.00%					
Deemed Equity %	40.00%					
	2015	**2016**	**2017**	**2018**	**2019**	**Totals**
Fixed Asset Continuity						
Opening Balance	-	9,875	9,625	9,375	9,125	
Additions	10,000	-	-	-	-	
Depreciation	(125)	(250)	(250)	(250)	(250)	
Closing Balance	9,875	9,625	9,375	9,125	8,875	
Average Balance	4,938	9,750	9,500	9,250	9,000	
UCC Continuity						
Opening	-	9,600	8,832	8,125	7,475	
Additions	10,000	-	-	-	-	
CCA	(400)	(768)	(707)	(650)	(598)	
Closing	9,600	8,832	8,125	7,475	6,877	
Cost of Capital						
Debt (Exhibit 5)	3.38%	3.38%	3.38%	3.53%	3.65%	
Equity (Exhibit 5)	9.36%	9.36%	9.36%	9.36%	9.36%	
Revenue Requirement						
Depreciation	125	250	250	250	250	1,125
Cost of Capital:						
Debt	100	198	193	196	197	884
Equity	185	365	356	346	337	1,589
PILs Gross-Up	(32)	(54)	(36)	(19)	(4)	(145)
Total	378	758	762	773	780	3,452
Deemed Equity	1,975	3,900	3,800	3,700	3,600	
Return on Deemed Equity	9.36%	9.36%	9.36%	9.36%	9.36%	
PILs Gross-Up Calculation for Rates						
Cost of Equity Capital	185	365	356	346	337	1,589
Add:						
Depreciation	125	250	250	250	250	1,125
Deduct:						
CCA	(400)	(768)	(707)	(650)	(598)	(3,123)
PILs Income (Loss)	(90)	(153)	(101)	(54)	(11)	(409)
PILs before Gross-Up	(24)	(40)	(26)	(14)	(3)	(107)
PILs Gross-Up	(32)	(54)	(36)	(19)	(4)	(145)

6-VECC-48 Table 1 (above) provides an example calculation of Revenue Requirement including its component depreciation, interest and PILs using an example of a $10 million addition to fixed assets in 2015 and under other assumptions shaded in blue. As expected, the resulting returns on deemed equity (shaded in yellow) correspond to the assumptions shaded in blue. The purpose of this table is to illustrate the regulatory income impact of this example.

The PILs Gross-Up for rates in the above table actually has a reducing effect on revenue requirement with respect to the incremental $10 million addition to fixed assets and corresponding incremental impact to rate base. Under the assumptions in the above table (which are meant to emphasize this issue), the significant excess of CCA over depreciation results in a loss for PILs purposes. The Rate-making methodology assumes that such losses on isolated incremental investments in rate base may be applied against PILs-able income generated from older distribution system assets. However, the example above clearly demonstrates that this particular investment will generate losses for PILs proxy purposes for several years with the corresponding impact of reducing revenue requirement.

Table 2: response to 6-VECC-48

HORIZON UTILITIES CORPORATION					6-VECC-48 Table 2
Response to 6-VECC-48					
($000s)					
	2015	**2016**	**2017**	**2018**	**2019**	**Totals**
Accounting Based Income						
Revenue Requirement	378	758	762	773	780	3,452
Less:						
Depreciation	(125)	(250)	(250)	(250)	(250)	(1,125)
Interest	(100)	(198)	(193)	(196)	(197)	(884)
Income before PILs	153	311	320	327	333	1,443
PILs (Accounting)	(40)	(82)	(84)	(86)	(87)	(379)
Net Income	113	229	236	241	246	1,064
Deemed Equity	1,975	3,900	3,800	3,700	3,600	
Return on Deemed Equity	5.70%	5.87%	6.21%	6.52%	6.82%	
PILs Reconciliation						
Income before PILs	153	311	320	327	333	1,443
Add:						
Depreciation	125	250	250	250	250	1,125
Deduct:						
CCA	(400)	(768)	(707)	(650)	(598)	(3,123)
PILs Income (Loss)	(122)	(207)	(137)	(73)	(15)	(554)
Current PILs Recovery (Exp)	32	54	36	19	4	145
Change - Future PILs Asset (Lia)	(72)	(136)	(120)	(105)	(91)	(524)
Accounting PILs	(40)	(82)	(84)	(86)	(87)	(379)
Future PILs Asset (Liability)	(72)	(208)	(328)	(433)	(524)	
Funds From Operations (Accounting)						
Net income	113	229	236	241	246	
Depreciation	125	250	250	250	250	
Change in Future Taxes	72	136	120	105	91	
FFO	310	615	606	596	587	
Funds From Operations (Regulated)						
Revenue Requirement	378	758	762	773	780	
Interest	(100)	(198)	(193)	(196)	(197)	
Regulatory PILs Gross-Up	32	54	36	19	4	
FFO	310	615	606	596	587	

6-VECC-48 Table 2 builds off of the example in 6-VECC-48 Table 1 and demonstrates the impact of that example on reported accounting income.

Under the assumptions in the previous table, it is clear that accounting-based returns on deemed equity are well below the deemed rates of return in 6-VECC-48 Table 1. This is explained by the requirement that accounting income reports, within the income tax provision, the future income tax implications of past transactions. 6-VECC-48 Table 1 reports a PILs Gross-Up credit of $32,000 for 2015. 6-VECC-48 Table 2 reports a current PILs recovery for accounting purposes of the same amount for 2015 (this is the expected effect of the PILs Proxy methodology). However, Table 6-VECC-48 Table 2 reports an overall PILs expense of $40,000 that comprises the current $32,000 recovery but also the Future PILs Expense of $72,000 to record the future tax cost of the excess of 2015 CCA over depreciation (effectively 26.5% * ($400,000 CCA less $125,000 depreciation)).

Rate-making methodology effectively implies that future tax assets and liabilities will be settled through future rates; since these are not settled with customers currently.

The example in 6-VECC-48 Table 2 demonstrates that customers effectively realize a current cumulative benefit of $524,000 of Future Tax Liabilities from 2015 to 2019. This amount will need to be settled in the future as the underlying CCA/ Depreciation timing differences reverse such that the former PILs Proxy losses turn into PILs Proxy income. At that time, the actual amount of PILs Proxy will exceed the accounting based income tax provision.

6-VECC-48 Table 2 also provides a reconciliation of Funds From Operations (“FFO”) for each of the accounting and regulatory basis of reporting income. These reconciliations demonstrate that cash flow is indifferent to the basis of reporting. Changes in Future Tax Assets/Liabilities do not affect cash. FFO is one key statistic for purposes of evaluating the creditworthiness of a business and is generally measured in relation to debt and interest expense.

The accounting-based and regulatory-based return on equity differences identified above have always existed under the PILs Proxy methodology but have been exacerbated by the transition to IFRS and more recent increases to CCA rates on distribution system assets. The transition to IFRS required a review of asset depreciable lives with the impact that such lives were extended materially for distribution system assets. The resulting growth of differences between depreciation and CCA is the principal contributor to a divergence in accounting based versus regulatory based returns on equity. This is likely to be a larger issue for utilities such as Horizon Utilities that require material increases to renewal-based capital expenditure programs with corresponding impact on rate base. Such growth utilities are more likely to experience lower accounting-based returns on equity than deemed rates for reasons demonstrated in the above tables. As a consequence, customers enjoy the rate benefit of relatively low cash taxes during the growth phase of a utility. However, the future tax liabilities accruing during such phase will eventually reverse and burden rates in the future.

Horizon Utilities is concerned that accounting-based returns do not appear to align well to rate-making policy with respect to its most material investment: distribution system assets. The principal difference arises from the treatment of Future PILs Assets/ Liabilities for accounting versus regulatory purposes. Given the anticipated growth in its capital expenditure programs and corresponding impact on future tax costs and liabilities, Horizon Utilities forecasts that its accounting based returns on equity will be significantly below the deemed rate of return. Table 6-13 illustrates this with respect to the 2015 Test Year.

As demonstrated in the above tables, current rate-making methodologies with respect to PILs have the following implications for distributors and their customers:

- Accounting based returns will not align to regulatory deemed returns given the mixed use of accounting and tax based values in the determination of revenue requirement. Accounting based returns will be lower than regulated returns during periods of significant rate base and capital growth and higher during stable or declining periods of growth;
- Distributors recover less PILs from customers than reported in accounting income during periods of rising investment and growth and, conversely, more during periods of stable or declining growth;

- The amount of current cash taxes paid by a distributor align to cash taxes recovered in rates;
- Distributors will recover or settle Future PILs liabilities or assets in future periods where the underlying accounting/ tax timing differences reverse.

A solution to this issue depends on the objectives with respect to the treatment of the distributor and its customers. Aligning accounting-based and regulatory-based returns on equity could be accomplished by one of the following:

- Include the Future PILs implications of current and historical costs and investments in distribution rates (i.e., impute the PILs proxy without adjustment for accounting/ tax differences);
- Change the basis of the recovery of fixed asset investments to CCA rather than depreciation.

At E6/T2/S1/Page 21, Horizon Utilities submitted its view that the Fair Return Standard ought to be the target for any year of a given investment and respectfully requested the Board comment on this matter. Recognizing that this is a very complex issue, Horizon Utilities does not have a preferred solution other than the matter be reviewed given its concerns that: i) the basis for determining regulatory income that achieves the deemed return on equity does not align in certain respects with the accounting basis of reporting income; ii) customers may not have adequate transparency with respect to the rate implications of future tax assets and liabilities.

Given the complexity of this issue, Horizon Utilities suggests that its resolution requires further study and may be outside the scope of this Application.

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7.0-VECC-49

Reference: E7/T1/S1, pg. 2 and pg. 6

a) For each of the customers in the proposed LU(2) class please describe the supply arrangements (i.e. how supply is obtained from Hydro One and the Horizon facilities used to deliver the power to the customer), including those circumstance where there is a unplanned or maintenance outage on their main supply facilities. In each case, please indicate whether any of the facilities used also provide (or can provide in the case other equipment outages) power to customers not in the LU(2) class.

b) Page 6 states that 100% of the customers in this rate class (LU(2)) are served "almost exclusively by dedicated conduit". Please indicate what the exceptions are. If some assets are "shared" with other classes, what are they and how is this treated in the cost allocation?

c) Do the LU(2) customers also have dedicated back-up "conduit" to ensure supply in cases of either an unplanned or maintenance outage of their main supply facilities?
- **If yes, is this also directly allocated?**
- **If not, how are they supplied during such outages? If supply is made from non-dedicated facilities, how is this addressed in the cost allocation?**

Response:

a) Horizon Utilities supplies all of the customers in the proposed LU (2) class via three Transformer Stations ("TSs") owned by Hydro One Networks Inc. ("Hydro One"), including breakers also owned by Hydro One. Horizon Utilities owns the Low Voltage ("LV") cables to the Hydro One breaker; the cable demarcation varies by customer. There are multiple feeders and breakers per customer within this customer class providing each customer with multiple redundancies. The available redundancies provide the ability to withstand unplanned outages due to a single cable fault, since these customers are served by multiple cables. These feeders are dedicated to the customers within the LU (2) class and cannot provide power to customers that are not in the LU(2) class.

b) Horizon Utilities wishes to clarify that several conduits make up a ductbank. Ductbanks pass through utility chambers and vaults, all of which would be classified as civil assets. The reference on page 6 should read "almost exclusively by civil assets". The electrical assets are dedicated to this customer class as well as the conduit in which the electrical assets reside. In certain circumstances, the remaining civil assets such as the utility chambers, vaults and any unutilized conduits are considered shared assets. Horizon Utilities has identified that the shared civil assets are fully depreciated and not material to the cost allocation process.

c) Horizon Utilities confirms that as provided in response to a) and b), these customers have multiple feeders servicing the site and the feeders are in conduits. Both the conduits and feeders are dedicated to the LU(2) class. This provides multiple redundancies to protect against an unplanned outage or maintenance.

7.0-VECC-50

Reference: E7/T1/S1/pg.3

a) Please indicate which accounts were impacted by the Elenchus recommendation (lines 22-24) and, using 2015 as the example, provide the asset values for each (gross book value) that were reassigned form primary to secondary.

Response:

The Accounts updated were:

- Account 1835 – Overhead Conductors and Devices
- Account 1845 – Underground Conductors and Devices

The split of assets between primary and secondary in these accounts in past years is known since each sub-account can be identified as either primary or secondary. However, on a prospective basis, forecasting is not done at the level of detail of the sub-accounts. Consequently, the forecast split (e.g., for 2015) between primary and secondary must rely on an estimate.

These are asset accounts; the proportions of primary and secondary sub-accounts will not change significantly from year to year. Consequently, the split of the accounts between primary and secondary is forecast to be the same as the historic split. The estimated increase in secondary assets is $14,266,000 in Account 1835 – Overhead Conductors and Devices and $16,652,000 in Account 1845 – Underground Conductors and Devices, based on the aforementioned assumption.

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7.0-VECC-51

Reference: E7/T1/S1/pg.6

a) With respect to Footnote 2, please confirm that for the new allocators described with the suffix "SU" the suffix should be LU2. If not please reconcile this footnote with page 9 of the Elenchus Report on Cost Allocation.

b) Why are there no wholesale meter costs (Acct. 1820-3) assigned/allocated to the LU(2) class (i.e. use of CENexLU2)?

Response:

a) Horizon Utilities confirms that the new allocators described with the suffix "SU" should be "LU (2)".

b) The engineering review of assets used to serve the customers in the LU (2) class determined that the feeders used to provide service to 2 of the customers are wholesale registered; these customers have paid for their own meters. Of the two remaining customers, one customer is supplied by wholesale meters at a Hydro One transformer station ("TS"). This entire TS along with the metering is at end of life and is being replaced over the term of this Application as discussed in 8-Staff-33. The cost for this project including the metering has been allocated to the LU2 class. The remaining LU (2) customer has older retail interval metering equipment and its net book value is approximately zero. This equipment is planned for replacement within the next two years; those costs will be allocated to the LU (2) customer class.

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7.0-VECC-52

Reference: E7/T1/S1/pg.7
Cost Allocation Model, Tab I5.2 Weighting Factors

a) Please explain why there are no Services weighing factors for the LU(1), LU(2), Sentinel Light, Street Lighting, USL or Backup/Stand By classes.

b) Please explain why there is no Billing and Collecting weighting factor for the Backup/Stand By class but Tab I6.2 reports bills issued to this class.

Response:

a) In evaluating the drivers of services related costs, Horizon Utilities concluded that the services related costs are driven mainly by the residential, GS < 50 kW, and GS > 50 kW classes. A calculation of each of the weighting factors is provided in response to 7-Energy Probe-53.

b) The Billing and Collecting related costs for standby are captured within the GS > 50kW class where most users of standby generation reside. Horizon Utilities believes that this is appropriate as the variable distribution rate for Standby Generation has been set at the variable distribution rate for the GS > 50 kW class.

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7.0-VECC-53

Reference: E7/T1/S1/pg.7
Cost Allocation Model, TabI6.2, Tab I7.1 and Tab I7.2

a) With respect to Tab I6.2, for each year 2015-2019, please reconcile the number of bills reported (CNB) with the number of customers (CCA) for the Sentinel and USL classes.

b) With respect to Tab I6.2, the number of bills reported for the Standby Class in 2015 (84) suggests there are 7 customers. However, Tab I7.1 reports only 6 meters for 2015. Please reconcile this for 2015 and any other years showing a similar inconsistency.

c) Please explain why Tab I6.2 does not show any customer count (CCA) for the Standby class.

d) Please explain why in Tab I7.2, for the LU(1) and LU(2) classes, the meter reading units are linked to number of bills (i.e., number of customers x number of bills annually per customer) as opposed to number of meter readings (I.e. number of meters x number of bills annually per customer).

Response:

a) In review of this interrogatory Horizon Utilities has concluded that the number of bills in the Cost Allocation model for the Sentinel and USL classes have been calculated using the number of connections when the calculation should have been completed using the number of customers. Table 1 provides the increase or decrease in the fully allocated costs to each rate class as a result of this change.

Table 1: Increase/(Decrease) in Fully Allocated Costs by Rate Class from Sentinel and USL Update

	2015 Increase/(Decrease)	2016 Increase/(Decrease)	2017 Increase/(Decrease)	2018 Increase/(Decrease)	2019 Increase/(Decrease)
Residential	$ 48,306	$ 48,740	$ 50,712	$ 49,531	$ 49,451
GS < 50 kW	$ 5,033	$ 5,057	$ 5,239	$ 5,095	$ 5,066
GS >50 to 4999 kW	$ 4,039	$ 4,104	$ 4,288	$ 4,206	$ 4,221
Standby	$ -	$ -	$ -	$ -	$ -
Large Use (1)	$ 290	$ 290	$ 299	$ 290	$ 287
Large Use (2)	$ 290	$ 290	$ 299	$ 290	$ 287
Sentinel Lights	$ (6,640)	$ (6,511)	$ (6,573)	$ (6,219)	$ (6,005)
Street Lighting	$ 3	$ 3	$ 3	$ 3	$ 3
Unmetered and Scattered	$ (51,321)	$ (51,973)	$ (54,268)	$ (53,195)	$ (53,310)

b) Horizon Utilities has confirmed that the number of Standby meters in Tab I7.1 should be 7. Horizon Utilities has also confirmed that updating to a value to 7 standby meters does not impact the fully allocated costs allocated to each rate class.

c) In review of this interrogatory Horizon Utilities has concluded that it would be more accurate to include the number of customers under CCA for the Standby class, however, Table 2 shows that updating for this information has a negligible impact on the fully allocated costs between rate classes.

Table 2: Increase/(Decrease) in Fully Allocated Costs by Rate Class from Standby Update

	2015 Increase/(Decrease)	2016 Increase/(Decrease)	2017 Increase/(Decrease)	2018 Increase/(Decrease)	2019 Increase/(Decrease)
Residential	$ (17)	$ (18)	$ (18)	$ (19)	$ (19)
GS < 50 kW	$ (1)	$ (1)	$ (2)	$ (2)	$ (2)
GS >50 to 4999 kW	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)
Standby	$ 22	$ 23	$ 23	$ 24	$ 25
Large Use (1)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)
Large Use (2)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)
Sentinel Lights	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)
Street Lighting	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)
Unmetered and Scattered	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)

d) Horizon Utilities has completed Tab I7.2 with the number of bills for each rate class, consistent with the approach approved by the Board in Horizon Utilities' 2011 Cost of Service Application (EB-2010-0131).

7.0-VECC-54

Reference: Cost Allocation Model, Tab I3

a) Please explain why there are no costs reported for Meter Reading Expense (Acct. 5310) or Customer Billing (Acct. 5315).

b) Where in the Trial Balance are these costs included.

c) Please break these costs out and revise the Cost Allocation Model accordingly.

Response:

a) Conventional meter reading is part of the services provided by Customer Care to Electricity Distribution Operations ("EDO") as described in Appendix 4-6.1, page 6, whereby a single fee is charged to EDO.

b) The meter reading costs are embedded in the single fee charged to EDO under Account 5340 - Miscellaneous Customer Accounts Expenses. This fee covers Call Centre Services, Credit and Collections, and Billing (which includes conventional meter reading).

c) As EDO effectively outsources its Customer Care function for a single fee, the Cost Allocation model cannot be revised to include a breakdown of these costs. Furthermore, the total amount of Account 5340 is allocated on the basis of Weighting Bills, and the Billing and Collecting weighting factor was derived on the basis of including the full charge parameters from EDO.

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7.0-VECC-55

Reference: E7/T1/S2/pg.1-2
E8/T3/S2/pg.9

The tariff sheet states that the standby charge is applied to the amount of reserve load transfer capacity contracted or the amount of monthly peak load displaced by a generating facility

a) Must all Standby customers contract for an "amount of load transfer capacity"?

b) With respect to Exhibit 8, please explain how Horizon determines whether or not Standby Power has been provided in a particular month.

c) How does Horizon determine whether the charge is to be applied to the load transfer capacity contracted or the amount of monthly peak load displaced?

d) If the later value (i.e. the amount of monthly peak load displaced) is used, how is it determined?

e) Do any of Horizon's current Large Use customers have load displacement generation? If so, do any of them currently contract for Standby power?

f) With respect to the proposed new deferral accounts for the LU(1) and LU(2) classes, please confirm that the actual loads in 2015-2019 could exceed the forecast for reasons that are totally unrelated to the fact these customers have load displacement generation.

g) With respect to the proposed new deferral account, why is it appropriate to establish such deferral accounts for the two Large Use classes that would return excess revenue if loads in the future exceed the forecast and not do the same for other customer classes?

Response:

a) Standby capacity is provided for either load displacement generation or for a second backup supply. Standby customers for a back-up supply request/contract for the amount of capacity they require Horizon Utilities to reserve on an alternate feeder based on their requirements. Customers with load displacement generation typically request standby capacity to meet their displaced load for times when the generation is off or operating at reduced output. For load displacement customers, the standby amount is calculated monthly based on the customer gross load less the billed demand.

b) For back up supply, the standby power is provided and charged based on the requested/contracted amount monthly. To avoid double billing, the billed demand is based on the single peak for load supplied whether it is from the regular supply or the back-up supply. For load displacement generation see response in a) above.

c) As stated in part b), for back up supply, the standby power is provided and charged based on the requested/contracted amount monthly.

d) As stated in part a), for load displacement customers the standby amount is calculated monthly based on the customer gross load less the billed demand.

e) No, Horizon Utilities current Large Use customers do not presently have load displacement generation.

f) As discussed in the response to 9-Staff-46, this request has been withdrawn.

g) As discussed in the response to 9-Staff-46, this request has been withdrawn.

7.0-VECC-56

Reference: E7/T1/Appendix 7-1
Cost Allocation Model, Tabs I9 and O5

a) With respect to Appendix 7-1, page 7, how many years of smart meter data does Horizon currently have and how many years' data are needed in order for the information to be used to establish load profiles for cost allocation?

b) With respect to Tabs I9 and O5, please confirm that the LU(2) class has been directly assigned assets in accounts 1840 and 1845 but has not been assigned or allocated any O&M costs associated with these assets.

c) If part (b) is confirmed, please revise the allocators for the O&M costs to include directly assigned assets and provide a revised Cost Allocation.

d) Tab I9 does not appear to attribute any depreciation to the assets directly assigned to the LU(2) class. Please indicate if this is done elsewhere in the cost allocation model and, if so where and what is the depreciation cost associated with these assets?

e) If not, please indicate what the associated depreciation cost would be and re-do the cost allocation with this cost also directly assigned to the LU(2) class.

Response:

a) Horizon Utilities believes that a minimum of four years of Smart Meter data after Smart Meters have been fully deployed is necessary in order to determine weather-sensitivity of load with weather normalization based on 30 years of historic weather data. As of June 2014, Horizon Utilities has 3 years of hourly Smart Meter data (beginning May 2011).

b) Horizon Utilities confirms that no O&M costs have been directly allocated to the LU(2) class. The LU (2) class is served with dedicated assets and essentially no O&M is required to maintain these dedicated assets (estimated at $7,000 every 3 years). Horizon Utilities plans to replace some of the dedicated assets and the capital costs associated with that project are directly allocated to the LU(2) class.

c) Per the answer in part b), no O&M costs are to be allocated to these assets.

d) Depreciation on the directly allocated assets is computed directly within cells J36 and J37 for each year's respective Cost Allocation model.

e) As stated in response to part d), the net fixed asset amounts are provided in the direct allocation tab and therefore include the impact of depreciation.

7.0-VECC-57

Reference: E7/T1/S2

a) Please confirm that if, in 2015, the fixed/variable split for the GS>50, LU(1) and LU(2) classes was adjusted to put more emphasis on the variable rate, then the revenue to cost ratio for the Standby class would improve.

b) What would be the resulting R/C ratios for 2015 if the revenue shortfall from reducing the ratios for LU(1), LU(2) and USL to the upper boundaries of their respective ranges was made up by first increasing the costs allocated to class with lowest value (i.e., Street Lighting – assuming Standby remains constant), until it reaches the value for the class with second lowest R/C, and then increasing both of these up to the third lowest class' value, etc. until the deficiency is eliminated?

Response:

a) It is true that if the variable component of revenue is increased for the GS > 50 kW class that the revenue-to-cost ratio for the standby class increases. This is the result of the proposed standby charge being set equal to the variable charge proposed for the GS < 50 kW class (where most users of standby generation reside). In lieu of a formal standby rate policy, Horizon Utilities cannot comment on whether this shift in the standby revenue-to-cost ratio represents an improvement.

It is not true that increasing the variable rate for the LU (1) and LU (2) classes would impact the revenue to cost ratio for the Standby class in 2015. The Standby revenue-to-cost ratio is representative only of existing standby customers within the GS < 50 kW class. Horizon Utilities has applied for standby rates for the LU (1) and LU (2) classes but it has specifically applied to set these rates at the variable rate for each class and has not incorporated this into the Cost Allocation process.

The discussion on standby rates is included at Exhibit 7, Tab 1, Schedule 2, Pages 1-2.

b) Horizon Utilities has provided the resulting revenue-to-cost ratios in response to Interrogatory 7-Energy Probe-49

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8.0-VECC-58

Reference: E8/T1/S2/pg.7

a) Please recalculate the 2015 rates for the residential class, keeping the fixed charge at the current level of $14.92.

b) Please re-do bill impact tables 8-44 to 8-50 using these alternative 2015 distribution rates.

Response:

a) Horizon Utilities has calculated the residential distribution rates maintaining the existing $14.92 fixed charge for 2015 – 2019. Table 1 provides the rates for each year.

Table 1: Residential Distribution Rates assuming $14.92 Fixed for all Test Years

	2015	2016	2017	2018	2019
Fixed	$14.92	$14.92	$14.92	$14.92	$14.92
Variable/kWh	$0.0185	$0.0205	$0.0214	$0.0221	$0.0235

b) Tables 8-44 to 8-50 have been provided as Tables 2–8, assuming the rates provided in part a).

Table 2: Residential Bill Impacts at 100 kWh (Revised Table 8-44)

Consumption 100 kWh ◉ May 1 - October 31

	Charge Unit	Volume	2014 Rates Rate ($)	2014 Rates Charge ($)	2015 Proposed Rates Rate ($)	2015 Proposed Rates Charge ($)	2015 vs 2014 $ Change	2015 vs 2014 % Change	2016 Proposed Rates Rate ($)	2016 Proposed Rates Charge ($)	2016 vs 2015 $ Change	2016 vs 2015 %
Monthly Service Charge	Monthly	1	$ 14.9200	$ 14.92	$14.9200	$ 14.92	$ -	0.00%	$14.9200	$ 14.92	$ -	0.00%
Smart Meter Rate Adder	Monthly	1		$ -		$ -	$ -			$ -	$ -	
Smart Meter Incremental Revenue	Monthly	1	$ 1.4700	$ 1.47	$ -	$ -	-$ 1.47	-100.00%	$ -	$ -	$ -	
Recovery of Green Energy Act	Monthly	1	$ 0.0400	$ 0.04	$ -	$ -	-$ 0.04	-100.00%	$ -	$ -	$ -	
Distribution Volumetric Rate	per kWh	100	$ 0.0147	$ 1.47	$ 0.0185	$ 1.85	$ 0.38	25.85%	$ 0.0205	$ 2.05	$ 0.20	10.81%
Smart Meter Disposition Rider	Monthly	1	$ -	$ -	$ 0.0100	$ 0.01	$ 0.01			$ -	-$ 0.01	-100.00%
LRAM & SSM Rate Rider	per kWh	100		$ -	-$ 0.0001	-$ 0.01	-$ 0.01			$ -	$ 0.01	-100.00%
Rate Rider for Tax Change	per kWh	100	-$ 0.0001	-$ 0.01	$ -	$ -	$ 0.01	-100.00%	$ -	$ -	$ -	
Sub-Total A (excluding pass through)				$ 17.89		$ 16.77	**-$ 1.12**	**-6.26%**		$ 16.97	**$ 0.20**	**1.19%**
Deferral/Variance Account	per kWh	100	-$ 0.0016	-$ 0.16	-$ 0.0007	-$ 0.07	$ 0.09	-56.25%	$ -	$ -	$ 0.07	-100.00%
Global Adjustment Sub-Account	per kWh	100	-$ 0.0002	-$ 0.02	$ 0.0012	$ 0.12	$ 0.14	-660.66%	$ -	$ -	-$ 0.12	-100.00%
1595	per kWh	100	$ -	$ -	$ 0.0001	$ 0.01	$ 0.01		$ -	$ -	-$ 0.01	-100.00%
Low Voltage Service Charge	per kWh	100	$ 0.00006	$ 0.01	$0.00006	$ 0.01	$ -	0.00%	$0.00006	$ 0.01	$ -	0.00%
Line Losses on Cost of Power		3.079	$ 0.0889	$ 0.27	$ 0.0889	$ 0.27	$ -	0.00%	$ 0.0889	$ 0.27	$ -	0.00%
Smart Meter Entity Charge	Monthly	1	$ 0.7900	$ 0.79	$ 0.7900	$ 0.79	$ -		$ 0.7900	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 18.78**		**$ 17.90**	**-$ 0.88**	**-4.68%**		**$ 18.04**	**$ 0.14**	**0.78%**
RTSR - Network	per kWh	103	$ 0.0072	$ 0.74	$ 0.0076	$ 0.78	$ 0.04	5.56%	$ 0.0078	$ 0.80	$ 0.02	2.63%
RTSR - Line and Transformation Connection	per kWh	103	$ 0.0052	$ 0.54	$ 0.0056	$ 0.58	$ 0.04	7.69%	$ 0.0057	$ 0.59	$ 0.01	1.79%
Sub-Total C - Delivery (including Sub-Total B)				**$ 20.06**		**$ 19.26**	**-$ 0.80**	**-3.97%**		**$ 19.43**	**$ 0.17**	**0.89%**
Wholesale Market Service Charge (WMSC)	per kWh	103	$ 0.0044	$ 0.45	$ 0.0044	$ 0.45	$ -	0.00%	$ 0.0044	$ 0.45	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	103	$ 0.0012	$ 0.12	$ 0.0012	$ 0.12	$ -	0.00%	$ 0.0013	$ 0.13	$ 0.01	8.33%
Standard Supply Service Charge	Monthly	1	$ 0.2500	$ 0.25	$ 0.2500	$ 0.25	$ -	0.00%	$ 0.2500	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	100	$ 0.0070	$ 0.70	$ 0.0070	$ 0.70	$ -	0.00%	$ 0.0070	$ 0.70	$ -	0.00%
TOU - Off Peak	per kWh	64	$ 0.0720	$ 4.61	$ 0.0720	$ 4.61	$ -	0.00%	$ 0.0720	$ 4.61	$ -	0.00%
TOU - Mid Peak	per kWh	18	$ 0.1090	$ 1.96	$ 0.1090	$ 1.96	$ -	0.00%	$ 0.1090	$ 1.96	$ -	0.00%
TOU - On Peak	per kWh	18	$ 0.1290	$ 2.32	$ 0.1290	$ 2.32	$ -	0.00%	$ 0.1290	$ 2.32	$ -	0.00%
Energy - RPP - Tier 1	per kWh	100	$ 0.0830	$ 8.30	$ 0.0830	$ 8.30	$ -	0.00%	$ 0.0830	$ 8.30	$ -	0.00%
Energy - RPP - Tier 2	per kWh	0	$ 0.0970	$ -	$ 0.0970	$ -	$ -	#DIV/0!	$ 0.0970	$ -	$ -	#DIV/0!
											$ -	
Total Bill on TOU (before Taxes)				**$ 30.48**		**$ 29.68**	**-$ 0.80**	**-2.61%**		**$ 29.86**	**$ 0.18**	**0.61%**
HST			13%	$ 3.96	13%	$ 3.86	-$ 0.10	-2.61%	13%	$ 3.88	$ 0.02	0.61%
Total Bill (including HST)				$ 34.44		$ 33.54	-$ 0.90	-2.61%		$ 33.74	$ 0.20	0.61%
Ontario Clean Energy Benefit				-$ 3.44		-$ 3.35	$ 0.09	-2.62%		-$ 3.37	-$ 0.02	0.60%
Total Bill on TOU (including				**$ 31.00**		**$ 30.19**	**-$ 0.81**	**-2.61%**		**$ 30.37**	**$ 0.18**	**0.61%**
											$ -	
Total Bill on RPP (before Taxes)				**$ 29.88**		**$ 29.09**	**-$ 0.80**	**-2.66%**		**$ 29.27**	**$ 0.18**	**0.62%**
HST			13%	$ 3.88	13%	$ 3.78	-$ 0.10	-2.66%	13%	$ 3.80	$ 0.02	0.62%
Total Bill (including HST)				$ 33.77		$ 32.87	-$ 0.90	-2.66%		$ 33.07	$ 0.20	0.62%
Ontario Clean Energy Benefit				-$ 3.38		-$ 3.29	$ 0.09	-2.66%		-$ 3.31	-$ 0.02	0.61%
Total Bill on RPP (including				**$ 30.39**		**$ 29.58**	**-$ 0.81**	**-2.66%**		**$ 29.76**	**$ 0.18**	**0.62%**
Loss Factor (%)			3.08%		3.08%				3.08%			

	2017 Proposed Rates Rate ($)	2017 Proposed Rates Charge ($)	2017 vs 2016 $ Change	2017 vs 2016 %	2018 Proposed Rates Rate ($)	2018 Proposed Rates Charge ($)	2018 vs 2017 $ Change	2018 vs 2017 %	2019 Proposed Rates Rate ($)	2019 Proposed Rates Charge ($)	2019 vs 2018 $ Change	2019 vs 2018 %
Monthly Service Charge	$14.9200	$ 14.92	$ -	0.00%	$14.9200	$ 14.92	$ -	0.00%	$14.9200	$ 14.92	$ -	0.00%
Smart Meter Rate Adder		$ -	$ -			$ -	$ -			$ -	$ -	
Smart Meter Incremental Revenue	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of Green Energy Act	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	$ 0.0214	$ 2.14	$ 0.09	4.39%	$ 0.0221	$ 2.21	$ 0.07	3.27%	$ 0.0235	$ 2.35	$ 0.14	6.33%
Smart Meter Disposition Rider		$ -	$ -			$ -	$ -			$ -	$ -	
LRAM & SSM Rate Rider		$ -	$ -			$ -	$ -			$ -	$ -	
Rate Rider for Tax Change	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)		$ 17.06	**$ 0.09**	**0.53%**		$ 17.13	**$ 0.07**	**0.41%**		$ 17.27	**$ 0.14**	**0.82%**
Deferral/Variance Account	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Global Adjustment Sub-Account	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
1595	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Low Voltage Service Charge	$0.00006	$ 0.01	$ -	0.00%	$0.00006	$ 0.01	$ -	0.00%	$0.00006	$ 0.01	-$ 0.00	-0.08%
Line Losses on Cost of Power	$ 0.0889	$ 0.27	$ -	0.00%	$ 0.0889	$ 0.27	$ -	0.00%	$ 0.0889	$ 0.27	$ -	0.00%
Smart Meter Entity Charge	$ 0.7900	$ 0.79	$ -		$ 0.7900	$ 0.79	$ -		$ -	$ -	-$ 0.79	
Sub-Total B - Distribution (includes Sub-Total A)		**$ 18.13**	**$ 0.09**	**0.50%**		**$ 18.20**	**$ 0.07**	**0.39%**		**$ 17.55**	**-$ 0.65**	**-3.57%**
RTSR - Network	$ 0.0081	$ 0.83	$ 0.03	3.85%	$ 0.0084	$ 0.87	$ 0.03	3.70%	$ 0.0086	$ 0.89	$ 0.02	2.38%
RTSR - Line and Transformation Connection	$ 0.0058	$ 0.60	$ 0.01	1.75%	$ 0.0060	$ 0.62	$ 0.02	3.45%	$ 0.0061	$ 0.63	$ 0.01	1.67%
Sub-Total C - Delivery (including Sub-Total B)		**$ 19.56**	**$ 0.13**	**0.68%**		**$ 19.68**	**$ 0.12**	**0.62%**		**$ 19.07**	**-$ 0.62**	**-3.15%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	$ 0.45	$ -	0.00%	$ 0.0044	$ 0.45	$ -	0.00%	$ 0.0044	$ 0.45	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	$ 0.13	$ -	0.00%	$ 0.0013	$ 0.13	$ -	0.00%	$ 0.0013	$ 0.13	$ -	0.00%
Standard Supply Service Charge	$ 0.2500	$ 0.25	$ -	0.00%	$ 0.2500	$ 0.25	$ -	0.00%	$ 0.2500	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	$ 0.0070	$ 0.70	$ -	0.00%	$ 0.0070	$ 0.70	$ -	0.00%	$ 0.0070	$ 0.70	$ -	0.00%
TOU - Off Peak	$ 0.0720	$ 4.61	$ -	0.00%	$ 0.0720	$ 4.61	$ -	0.00%	$ 0.0720	$ 4.61	$ -	0.00%
TOU - Mid Peak	$ 0.1090	$ 1.96	$ -	0.00%	$ 0.1090	$ 1.96	$ -	0.00%	$ 0.1090	$ 1.96	$ -	0.00%
TOU - On Peak	$ 0.1290	$ 2.32	$ -	0.00%	$ 0.1290	$ 2.32	$ -	0.00%	$ 0.1290	$ 2.32	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0830	$ 8.30	$ -	0.00%	$ 0.0830	$ 8.30	$ -	0.00%	$ 0.0830	$ 8.30	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0970	$ -	$ -	#DIV/0!	$ 0.0970	$ -	$ -	#DIV/0!	$ 0.0970	$ -	$ -	#DIV/0!
			$ -				$ -				$ -	
Total Bill on TOU (before Taxes)		**$ 29.99**	**$ 0.13**	**0.44%**		**$ 30.11**	**$ 0.12**	**0.41%**		**$ 29.49**	**-$ 0.62**	**-2.06%**
HST	13%	$ 3.90	$ 0.02	0.44%	13%	$ 3.91	$ 0.02	0.41%	13%	$ 3.83	-$ 0.08	-2.06%
Total Bill (including HST)		$ 33.89	$ 0.15	0.44%		$ 34.03	$ 0.14	0.41%		$ 33.33	-$ 0.70	-2.06%
Ontario Clean Energy Benefit		-$ 3.39	-$ 0.02	0.59%		-$ 3.40	-$ 0.01	0.29%		-$ 3.33	$ 0.07	-2.06%
Total Bill on TOU (including		**$ 30.50**	**$ 0.13**	**0.42%**		**$ 30.63**	**$ 0.13**	**0.42%**		**$ 30.00**	**-$ 0.63**	**-2.06%**
			$ -				$ -				$ -	
Total Bill on RPP (before Taxes)		**$ 29.40**	**$ 0.13**	**0.45%**		**$ 29.52**	**$ 0.12**	**0.41%**		**$ 28.90**	**-$ 0.62**	**-2.10%**
HST	13%	$ 3.82	$ 0.02	0.45%	13%	$ 3.84	$ 0.02	0.41%	13%	$ 3.76	-$ 0.08	-2.10%
Total Bill (including HST)		$ 33.22	$ 0.15	0.45%		$ 33.36	$ 0.14	0.41%		$ 32.66	-$ 0.70	-2.10%
Ontario Clean Energy Benefit		-$ 3.32	-$ 0.01	0.30%		-$ 3.34	-$ 0.02	0.60%		-$ 3.27	$ 0.07	-2.10%
Total Bill on RPP (including		**$ 29.90**	**$ 0.14**	**0.46%**		**$ 30.02**	**$ 0.12**	**0.39%**		**$ 29.39**	**-$ 0.63**	**-2.10%**
Loss Factor (%)	3.08%				3.08%				3.08%			

Table 3: Residential Bill Impacts at 200 kWh (Revised Table 8-45)

			2014 Rates		2015 Proposed Rates		2015 vs 2014		2016 Proposed Rates		2016 vs 2015		2017 Proposed Rates		2017 vs 2016		2018 Proposed Rates		2018 vs 2017		2019 Proposed Rates		2019 vs 2018	
	Charge Unit	Volume	Rate ($)	Charge ($)	Rate ($)	Charge ($)	$ Change	% Change	Rate ($)	Charge ($)	$ Change	%	Rate ($)	Charge ($)	$ Change	%	Rate ($)	Charge ($)	$ Change	%	Rate ($)	Charge ($)	$ Change	%
Monthly Service Charge	Monthly	1	$ 14.9200	$ 14.92	$14.9200	$ 14.92	$ -	0.00%	$14.9200	$ 14.92	$ -	0.00%	$14.9200	$ 14.92	$ -	0.00%	$14.9200	$ 14.92	$ -	0.00%	$14.9200	$ 14.92	$ -	0.00%
Smart Meter Rate Adder	Monthly	1		$ -		$ -	$ -			$ -	$ -			$ -	$ -			$ -	$ -			$ -	$ -	
Smart Meter Incremental Revenue	Monthly	1	$ 1.4700	$ 1.47	$ -	$ -	-$ 1.47	-100.00%	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of Green Energy Act	Monthly	1	$ 0.0400	$ 0.04	$ -	$ -	-$ 0.04	-100.00%	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	per kWh	200	$ 0.0147	$ 2.94	$ 0.0185	$ 3.70	$ 0.76	25.85%	$ 0.0205	$ 4.10	$ 0.40	10.81%	$ 0.0214	$ 4.28	$ 0.18	4.39%	$ 0.0221	$ 4.42	$ 0.14	3.27%	$ 0.0235	$ 4.70	$ 0.28	6.33%
Smart Meter Disposition Rider	Monthly	1	$ -	$ -	$ 0.0100	$ 0.01	$ 0.01			$ -	-$ 0.01	-100.00%		$ -	$ -			$ -	$ -			$ -	$ -	
LRAM & SSM Rate Rider	per kWh	200		$ -	-$ 0.0001	-$ 0.02	-$ 0.02			$ -	$ 0.02	-100.00%		$ -	$ -			$ -	$ -			$ -	$ -	
Rate Rider for Tax Change	per kWh	200	-$ 0.0001	-$ 0.02	$ -	$ -	$ 0.02	-100.00%	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)				$ 19.35		$ 18.61	**-$ 0.74**	**-3.82%**		$ 19.02	**$ 0.41**	**2.20%**		$ 19.20	**$ 0.18**	**0.95%**		$ 19.34	**$ 0.14**	**0.73%**		$ 19.62	**$ 0.28**	**1.45%**
Deferral/Variance Account	per kWh	200	-$ 0.0016	-$ 0.32	-$ 0.0007	-$ 0.14	$ 0.18	-56.25%	$ -	$ -	$ 0.14	-100.00%	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Global Adjustment Sub-Account	per kWh	200	-$ 0.0002	-$ 0.04	$ 0.0012	$ 0.24	$ 0.28	-660.66%	$ -	$ -	-$ 0.24	-100.00%	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
1595	per kWh	200	$ -	$ -	$ 0.0001	$ 0.02	$ 0.02		$ -	$ -	-$ 0.02	-100.00%	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Low Voltage Service Charge	per kWh	200	$ 0.00006	$ 0.01	$0.00006	$ 0.01	$ -	0.00%	$0.00006	$ 0.01	$ -	0.00%	$0.00006	$ 0.01	$ -	0.00%	$0.00006	$ 0.01	$ -	0.00%	$0.00006	$ 0.01	-$ 0.00	-0.08%
Line Losses on Cost of Power		6.158	$ 0.0889	$ 0.55	$ 0.0889	$ 0.55	$ -	0.00%	$ 0.0889	$ 0.55	$ -	0.00%	$ 0.0889	$ 0.55	$ -	0.00%	$ 0.0889	$ 0.55	$ -	0.00%	$ 0.0889	$ 0.55	$ -	0.00%
Smart Meter Entity Charge	Monthly	1	$ 0.7900	$ 0.79	$ 0.7900	$ 0.79	$ -		$ 0.7900	$ 0.79	$ -		$ 0.7900	$ 0.79	$ -		$ 0.7900	$ 0.79	$ -		$ -	$ -	-$ 0.79	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 20.34**		**$ 20.08**	**-$ 0.26**	**-1.26%**		**$ 20.37**	**$ 0.29**	**1.44%**		**$ 20.55**	**$ 0.18**	**0.88%**		**$ 20.69**	**$ 0.14**	**0.68%**		**$ 20.18**	**-$ 0.51**	**-2.47%**
RTSR - Network	per kWh	206	$ 0.0072	$ 1.48	$ 0.0076	$ 1.57	$ 0.08	5.56%	$ 0.0078	$ 1.61	$ 0.04	2.63%	$ 0.0081	$ 1.67	$ 0.06	3.85%	$ 0.0084	$ 1.73	$ 0.06	3.70%	$ 0.0086	$ 1.77	$ 0.04	2.38%
RTSR - Line and Transformation Connection	per kWh	206	$ 0.0052	$ 1.07	$ 0.0056	$ 1.15	$ 0.08	7.69%	$ 0.0057	$ 1.18	$ 0.02	1.79%	$ 0.0058	$ 1.20	$ 0.02	1.75%	$ 0.0060	$ 1.24	$ 0.04	3.45%	$ 0.0061	$ 1.26	$ 0.02	1.67%
Sub-Total C - Delivery (including Sub-Total B)				**$ 22.89**		**$ 22.80**	**-$ 0.09**	**-0.40%**		**$ 23.15**	**$ 0.35**	**1.54%**		**$ 23.42**	**$ 0.26**	**1.13%**		**$ 23.66**	**$ 0.24**	**1.04%**		**$ 23.21**	**-$ 0.45**	**-1.89%**
Wholesale Market Service Charge (WMSC)	per kWh	206	$ 0.0044	$ 0.91	$ 0.0044	$ 0.91	$ -	0.00%	$ 0.0044	$ 0.91	$ -	0.00%	$ 0.0044	$ 0.91	$ -	0.00%	$ 0.0044	$ 0.91	$ -	0.00%	$ 0.0044	$ 0.91	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	206	$ 0.0012	$ 0.25	$ 0.0012	$ 0.25	$ -	0.00%	$ 0.0013	$ 0.27	$ 0.02	8.33%	$ 0.0013	$ 0.27	$ -	0.00%	$ 0.0013	$ 0.27	$ -	0.00%	$ 0.0013	$ 0.27	$ -	0.00%
Standard Supply Service Charge	Monthly	1	$ 0.2500	$ 0.25	$ 0.2500	$ 0.25	$ -	0.00%	$ 0.2500	$ 0.25	$ -	0.00%	$ 0.2500	$ 0.25	$ -	0.00%	$ 0.2500	$ 0.25	$ -	0.00%	$ 0.2500	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	200	$ 0.0070	$ 1.40	$ 0.0070	$ 1.40	$ -	0.00%	$ 0.0070	$ 1.40	$ -	0.00%	$ 0.0070	$ 1.40	$ -	0.00%	$ 0.0070	$ 1.40	$ -	0.00%	$ 0.0070	$ 1.40	$ -	0.00%
TOU - Off Peak	per kWh	128	$ 0.0720	$ 9.22	$ 0.0720	$ 9.22	$ -	0.00%	$ 0.0720	$ 9.22	$ -	0.00%	$ 0.0720	$ 9.22	$ -	0.00%	$ 0.0720	$ 9.22	$ -	0.00%	$ 0.0720	$ 9.22	$ -	0.00%
TOU - Mid Peak	per kWh	36	$ 0.1090	$ 3.92	$ 0.1090	$ 3.92	$ -	0.00%	$ 0.1090	$ 3.92	$ -	0.00%	$ 0.1090	$ 3.92	$ -	0.00%	$ 0.1090	$ 3.92	$ -	0.00%	$ 0.1090	$ 3.92	$ -	0.00%
TOU - On Peak	per kWh	36	$ 0.1290	$ 4.64	$ 0.1290	$ 4.64	$ -	0.00%	$ 0.1290	$ 4.64	$ -	0.00%	$ 0.1290	$ 4.64	$ -	0.00%	$ 0.1290	$ 4.64	$ -	0.00%	$ 0.1290	$ 4.64	$ -	0.00%
Energy - RPP - Tier 1	per kWh	200	$ 0.0830	$ 16.60	$ 0.0830	$ 16.60	$ -	0.00%	$ 0.0830	$ 16.60	$ -	0.00%	$ 0.0830	$ 16.60	$ -	0.00%	$ 0.0830	$ 16.60	$ -	0.00%	$ 0.0830	$ 16.60	$ -	0.00%
Energy - RPP - Tier 2	per kWh	0	$ 0.0970	$ -	$ 0.0970	$ -	$ -	#DIV/0!	$ 0.0970	$ -	$ -	#DIV/0!	$ 0.0970	$ -	$ -	#DIV/0!	$ 0.0970	$ -	$ -	#DIV/0!	$ 0.0970	$ -	$ -	#DIV/0!
											$ -				$ -				$ -				$ -	
Total Bill on TOU (before Taxes)				**$ 43.48**		**$ 43.39**	**-$ 0.09**	**-0.21%**		**$ 43.76**	**$ 0.37**	**0.86%**		**$ 44.02**	**$ 0.26**	**0.60%**		**$ 44.27**	**$ 0.24**	**0.55%**		**$ 43.82**	**-$ 0.45**	**-1.01%**
HST			13%	$ 5.65	13%	$ 5.64	-$ 0.01	-0.21%	13%	$ 5.69	$ 0.05	0.86%	13%	$ 5.72	$ 0.03	0.60%	13%	$ 5.75	$ 0.03	0.55%	13%	$ 5.70	-$ 0.06	-1.01%
Total Bill (including HST)				$ 49.13		$ 49.03	-$ 0.10	-0.21%		$ 49.45	$ 0.42	0.86%		$ 49.75	$ 0.30	0.60%		$ 50.02	$ 0.27	0.55%		$ 49.52	-$ 0.51	-1.01%
Ontario Clean Energy Benefit				-$ 4.91		-$ 4.90	$ 0.01	-0.20%		-$ 4.95	-$ 0.05	1.02%		-$ 4.97	-$ 0.02	0.40%		-$ 5.00	-$ 0.03	0.60%		-$ 4.95	$ 0.05	-1.00%
Total Bill on TOU (including				**$ 44.22**		**$ 44.13**	**-$ 0.09**	**-0.21%**		**$ 44.50**	**$ 0.37**	**0.84%**		**$ 44.78**	**$ 0.28**	**0.62%**		**$ 45.02**	**$ 0.24**	**0.55%**		**$ 44.57**	**-$ 0.46**	**-1.01%**
											$ -				$ -				$ -				$ -	
Total Bill on RPP (before Taxes)				**$ 42.30**		**$ 42.21**	**-$ 0.09**	**-0.22%**		**$ 42.58**	**$ 0.37**	**0.88%**		**$ 42.84**	**$ 0.26**	**0.62%**		**$ 43.08**	**$ 0.24**	**0.57%**		**$ 42.64**	**-$ 0.45**	**-1.04%**
HST			13%	$ 5.50	13%	$ 5.49	-$ 0.01	-0.22%	13%	$ 5.54	$ 0.05	0.88%	13%	$ 5.57	$ 0.03	0.62%	13%	$ 5.60	$ 0.03	0.57%	13%	$ 5.54	-$ 0.06	-1.04%
Total Bill (including HST)				$ 47.80		$ 47.69	-$ 0.10	-0.22%		$ 48.11	$ 0.42	0.88%		$ 48.41	$ 0.30	0.62%		$ 48.68	$ 0.27	0.57%		$ 48.18	-$ 0.51	-1.04%
Ontario Clean Energy Benefit				-$ 4.78		-$ 4.77	$ 0.01	-0.21%		-$ 4.81	-$ 0.04	0.84%		-$ 4.84	-$ 0.03	0.62%		-$ 4.87	-$ 0.03	0.62%		-$ 4.82	$ 0.05	-1.03%
Total Bill on RPP (including				**$ 43.02**		**$ 42.92**	**-$ 0.09**	**-0.22%**		**$ 43.30**	**$ 0.38**	**0.89%**		**$ 43.57**	**$ 0.27**	**0.62%**		**$ 43.81**	**$ 0.24**	**0.56%**		**$ 43.36**	**-$ 0.46**	**-1.04%**
Loss Factor (%)			3.08%		3.08%				3.08%				3.08%				3.08%				3.08%			

Table 4: Residential Bill Impacts at 500 kWh (Revised Table 8-46)

			2014 Rates		2015 Proposed Rates		2015 vs 2014		2016 Proposed Rates		2016 vs 2015		2017 Proposed Rates		2017 vs 2016		2018 Proposed Rates		2018 vs 2017		2019 Proposed Rates		2019 vs 2018	
	Charge Unit	Volume	Rate ($)	Charge ($)	Rate ($)	Charge ($)	$ Change	% Change	Rate ($)	Charge ($)	$ Change	%	Rate ($)	Charge ($)	$ Change	%	Rate ($)	Charge ($)	$ Change	%	Rate ($)	Charge ($)	$ Change	%
Monthly Service Charge	Monthly	1	$ 14.9200	$ 14.92	$14.9200	$ 14.92	$ -	0.00%	$14.9200	$ 14.92	$ -	0.00%	$14.9200	$ 14.92	$ -	0.00%	$14.9200	$ 14.92	$ -	0.00%	$14.9200	$ 14.92	$ -	0.00%
Smart Meter Rate Adder	Monthly	1		$ -		$ -	$ -			$ -	$ -			$ -	$ -			$ -	$ -			$ -	$ -	
Smart Meter Incremental Revenue	Monthly	1	$ 1.4700	$ 1.47	$ -	$ -	-$ 1.47	-100.00%	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of Green Energy Act	Monthly	1	$ 0.0400	$ 0.04	$ -	$ -	-$ 0.04	-100.00%	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	per kWh	500	$ 0.0147	$ 7.35	$ 0.0185	$ 9.25	$ 1.90	25.85%	$ 0.0205	$ 10.25	$ 1.00	10.81%	$ 0.0214	$ 10.70	$ 0.45	4.39%	$ 0.0221	$ 11.05	$ 0.35	3.27%	$ 0.0235	$ 11.75	$ 0.70	6.33%
Smart Meter Disposition Rider	Monthly	1	$ -	$ -	$ 0.0100	$ 0.01	$ 0.01			$ -	-$ 0.01	-100.00%		$ -	$ -			$ -	$ -			$ -	$ -	
LRAM & SSM Rate Rider	per kWh	500		$ -	-$ 0.0001	-$ 0.05	-$ 0.05			$ -	$ 0.05	-100.00%		$ -	$ -			$ -	$ -			$ -	$ -	
Rate Rider for Tax Change	per kWh	500	-$ 0.0001	-$ 0.05	$ -	$ -	$ 0.05	-100.00%	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)				$ 23.73		$ 24.13	**$ 0.40**	**1.69%**		$ 25.17	**$ 1.04**	**4.31%**		$ 25.62	**$ 0.45**	**1.79%**		$ 25.97	**$ 0.35**	**1.37%**		$ 26.67	**$ 0.70**	**2.70%**
Deferral/Variance Account	per kWh	500	-$ 0.0016	-$ 0.80	-$ 0.0007	-$ 0.35	$ 0.45	-56.25%	$ -	$ -	$ 0.35	-100.00%	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Global Adjustment Sub-Account	per kWh	500	-$ 0.0002	-$ 0.11	$ 0.0012	$ 0.60	$ 0.71	-660.66%	$ -	$ -	-$ 0.60	-100.00%	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
1595	per kWh	500	$ -	$ -	$ 0.0001	$ 0.05	$ 0.05		$ -	$ -	-$ 0.05	-100.00%	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Low Voltage Service Charge	per kWh	500	$ 0.00006	$ 0.03	$0.00006	$ 0.03	$ -	0.00%	$0.00006	$ 0.03	$ -	0.00%	$0.00006	$ 0.03	$ -	0.00%	$0.00006	$ 0.03	$ -	0.00%	$0.00006	$ 0.03	-$ 0.00	-0.08%
Line Losses on Cost of Power		15.395	$ 0.0889	$ 1.37	$ 0.0889	$ 1.37	$ -	0.00%	$ 0.0889	$ 1.37	$ -	0.00%	$ 0.0889	$ 1.37	$ -	0.00%	$ 0.0889	$ 1.37	$ -	0.00%	$ 0.0889	$ 1.37	$ -	0.00%
Smart Meter Entity Charge	Monthly	1	$ 0.7900	$ 0.79	$ 0.7900	$ 0.79	$ -		$ 0.7900	$ 0.79	$ -		$ 0.7900	$ 0.79	$ -		$ 0.7900	$ 0.79	$ -		$ -	$ -	-$ 0.79	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 25.01**		**$ 26.62**	**$ 1.61**	**6.43%**		**$ 27.36**	**$ 0.74**	**2.78%**		**$ 27.81**	**$ 0.45**	**1.64%**		**$ 28.16**	**$ 0.35**	**1.26%**		**$ 28.07**	**-$ 0.09**	**-0.32%**
RTSR - Network	per kWh	515	$ 0.0072	$ 3.71	$ 0.0076	$ 3.92	$ 0.21	5.56%	$ 0.0078	$ 4.02	$ 0.10	2.63%	$ 0.0081	$ 4.17	$ 0.15	3.85%	$ 0.0084	$ 4.33	$ 0.15	3.70%	$ 0.0086	$ 4.43	$ 0.10	2.38%
RTSR - Line and Transformation Connection	per kWh	515	$ 0.0052	$ 2.68	$ 0.0056	$ 2.89	$ 0.21	7.69%	$ 0.0057	$ 2.94	$ 0.05	1.79%	$ 0.0058	$ 2.99	$ 0.05	1.75%	$ 0.0060	$ 3.09	$ 0.10	3.45%	$ 0.0061	$ 3.14	$ 0.05	1.67%
Sub-Total C - Delivery (including Sub-Total B)				**$ 31.40**		**$ 33.42**	**$ 2.02**	**6.43%**		**$ 34.32**	**$ 0.89**	**2.68%**		**$ 34.97**	**$ 0.66**	**1.91%**		**$ 35.58**	**$ 0.61**	**1.74%**		**$ 35.65**	**$ 0.06**	**0.18%**
Wholesale Market Service Charge (WMSC)	per kWh	515	$ 0.0044	$ 2.27	$ 0.0044	$ 2.27	$ -	0.00%	$ 0.0044	$ 2.27	$ -	0.00%	$ 0.0044	$ 2.27	$ -	0.00%	$ 0.0044	$ 2.27	$ -	0.00%	$ 0.0044	$ 2.27	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	515	$ 0.0012	$ 0.62	$ 0.0012	$ 0.62	$ -	0.00%	$ 0.0013	$ 0.67	$ 0.05	8.33%	$ 0.0013	$ 0.67	$ -	0.00%	$ 0.0013	$ 0.67	$ -	0.00%	$ 0.0013	$ 0.67	$ -	0.00%
Standard Supply Service Charge	Monthly	1	$ 0.2500	$ 0.25	$ 0.2500	$ 0.25	$ -	0.00%	$ 0.2500	$ 0.25	$ -	0.00%	$ 0.2500	$ 0.25	$ -	0.00%	$ 0.2500	$ 0.25	$ -	0.00%	$ 0.2500	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	500	$ 0.0070	$ 3.50	$ 0.0070	$ 3.50	$ -	0.00%	$ 0.0070	$ 3.50	$ -	0.00%	$ 0.0070	$ 3.50	$ -	0.00%	$ 0.0070	$ 3.50	$ -	0.00%	$ 0.0070	$ 3.50	$ -	0.00%
TOU - Off Peak	per kWh	320	$ 0.0720	$ 23.04	$ 0.0720	$ 23.04	$ -	0.00%	$ 0.0720	$ 23.04	$ -	0.00%	$ 0.0720	$ 23.04	$ -	0.00%	$ 0.0720	$ 23.04	$ -	0.00%	$ 0.0720	$ 23.04	$ -	0.00%
TOU - Mid Peak	per kWh	90	$ 0.1090	$ 9.81	$ 0.1090	$ 9.81	$ -	0.00%	$ 0.1090	$ 9.81	$ -	0.00%	$ 0.1090	$ 9.81	$ -	0.00%	$ 0.1090	$ 9.81	$ -	0.00%	$ 0.1090	$ 9.81	$ -	0.00%
TOU - On Peak	per kWh	90	$ 0.1290	$ 11.61	$ 0.1290	$ 11.61	$ -	0.00%	$ 0.1290	$ 11.61	$ -	0.00%	$ 0.1290	$ 11.61	$ -	0.00%	$ 0.1290	$ 11.61	$ -	0.00%	$ 0.1290	$ 11.61	$ -	0.00%
Energy - RPP - Tier 1	per kWh	500	$ 0.0830	$ 41.50	$ 0.0830	$ 41.50	$ -	0.00%	$ 0.0830	$ 41.50	$ -	0.00%	$ 0.0830	$ 41.50	$ -	0.00%	$ 0.0830	$ 41.50	$ -	0.00%	$ 0.0830	$ 41.50	$ -	0.00%
Energy - RPP - Tier 2	per kWh	0	$ 0.0970	$ -	$ 0.0970	$ -	$ -	#DIV/0!	$ 0.0970	$ -	$ -	#DIV/0!	$ 0.0970	$ -	$ -	#DIV/0!	$ 0.0970	$ -	$ -	#DIV/0!	$ 0.0970	$ -	$ -	#DIV/0!
											$ -				$ -				$ -				$ -	
Total Bill on TOU (before Taxes)				**$ 82.50**		**$ 84.52**	**$ 2.02**	**2.45%**		**$ 85.46**	**$ 0.95**	**1.12%**		**$ 86.12**	**$ 0.66**	**0.77%**		**$ 86.73**	**$ 0.61**	**0.71%**		**$ 86.79**	**$ 0.06**	**0.07%**
HST			13%	$ 10.72	13%	$ 10.99	$ 0.26	2.45%	13%	$ 11.11	$ 0.12	1.12%	13%	$ 11.20	$ 0.09	0.77%	13%	$ 11.27	$ 0.08	0.71%	13%	$ 11.28	$ 0.01	0.07%
Total Bill (including HST)				$ 93.22		$ 95.51	$ 2.28	2.45%		$ 96.57	$ 1.07	1.12%		$ 97.32	$ 0.74	0.77%		$ 98.00	$ 0.69	0.71%		$ 98.08	$ 0.07	0.07%
Ontario Clean Energy Benefit				-$ 9.32		-$ 9.55	-$ 0.23	2.47%		-$ 9.66	-$ 0.11	1.15%		-$ 9.73	-$ 0.07	0.72%		-$ 9.80	-$ 0.07	0.72%		-$ 9.81	-$ 0.01	0.10%
Total Bill on TOU (including				**$ 83.90**		**$ 85.96**	**$ 2.05**	**2.45%**		**$ 86.91**	**$ 0.96**	**1.12%**		**$ 87.59**	**$ 0.67**	**0.77%**		**$ 88.20**	**$ 0.62**	**0.70%**		**$ 88.27**	**$ 0.06**	**0.07%**
											$ -				$ -				$ -				$ -	
Total Bill on RPP (before Taxes)				**$ 79.54**		**$ 81.56**	**$ 2.02**	**2.54%**		**$ 82.50**	**$ 0.95**	**1.16%**		**$ 83.16**	**$ 0.66**	**0.80%**		**$ 83.77**	**$ 0.61**	**0.73%**		**$ 83.83**	**$ 0.06**	**0.08%**
HST			13%	$ 10.34	13%	$ 10.60	$ 0.26	2.54%	13%	$ 10.73	$ 0.12	1.16%	13%	$ 10.81	$ 0.09	0.80%	13%	$ 10.89	$ 0.08	0.73%	13%	$ 10.90	$ 0.01	0.08%
Total Bill (including HST)				$ 89.88		$ 92.16	$ 2.28	2.54%		$ 93.23	$ 1.07	1.16%		$ 93.97	$ 0.74	0.80%		$ 94.66	$ 0.69	0.73%		$ 94.73	$ 0.07	0.08%
Ontario Clean Energy Benefit				-$ 8.99		-$ 9.22	-$ 0.23	2.56%		-$ 9.32	-$ 0.10	1.08%		-$ 9.40	-$ 0.08	0.86%		-$ 9.47	-$ 0.07	0.74%		-$ 9.47	$ -	0.00%
Total Bill on RPP (including				**$ 80.89**		**$ 82.94**	**$ 2.05**	**2.54%**		**$ 83.91**	**$ 0.97**	**1.17%**		**$ 84.57**	**$ 0.66**	**0.79%**		**$ 85.19**	**$ 0.62**	**0.73%**		**$ 85.26**	**$ 0.07**	**0.09%**
Loss Factor (%)			3.08%		3.08%				3.08%				3.08%				3.08%				3.08%			

Table 5: Residential Bill Impacts at 800 kWh (Revised Table 8-47)

	Charge Unit	Volume	2014 Rates Rate ($)	2014 Rates Charge ($)	2015 Proposed Rates Rate ($)	2015 Proposed Rates Charge ($)	2015 vs 2014 $ Change	2015 vs 2014 % Change	2016 Proposed Rates Rate ($)	2016 Proposed Rates Charge ($)	2016 vs 2015 $ Change	2016 vs 2015 %
Monthly Service Charge	Monthly	1	$ 14.9200	$ 14.92	$14.9200	$ 14.92	$ -	0.00%	$14.9200	$ 14.92	$ -	0.00%
Smart Meter Rate Adder	Monthly	1		$ -		$ -	$ -			$ -	$ -	
Smart Meter Incremental Revenue	Monthly	1	$ 1.4700	$ 1.47	$ -	$ -	-$ 1.47	-100.00%	$ -	$ -	$ -	
Recovery of Green Energy Act	Monthly	1	$ 0.0400	$ 0.04	$ -	$ -	-$ 0.04	-100.00%	$ -	$ -	$ -	
Distribution Volumetric Rate	per kWh	800	$ 0.0147	$ 11.76	$ 0.0185	$ 14.80	$ 3.04	25.85%	$ 0.0205	$ 16.40	$ 1.60	10.81%
Smart Meter Disposition Rider	Monthly	1	$ -	$ -	$ 0.0100	$ 0.01	$ 0.01			$ -	-$ 0.01	-100.00%
LRAM & SSM Rate Rider	per kWh	800		$ -	-$ 0.0001	-$ 0.08	-$ 0.08			$ -	$ 0.08	-100.00%
Rate Rider for Tax Change	per kWh	800	-$ 0.0001	-$ 0.08	$ -	$ -	$ 0.08	-100.00%	$ -	$ -	$ -	
Sub-Total A (excluding pass through)				$ 28.11		$ 29.65	**$ 1.54**	**5.48%**		$ 31.32	**$ 1.67**	**5.63%**
Deferral/Variance Account	per kWh	800	-$ 0.0016	-$ 1.28	-$ 0.0007	-$ 0.56	$ 0.72	-56.25%	$ -	$ -	$ 0.56	-100.00%
Global Adjustment Sub-Account	per kWh	800	-$ 0.0002	-$ 0.17	$ 0.0012	$ 0.96	$ 1.13	-660.66%	$ -	$ -	-$ 0.96	-100.00%
1595	per kWh	800	$ -	$ -	$ 0.0001	$ 0.08	$ 0.08		$ -	$ -	-$ 0.08	-100.00%
Low Voltage Service Charge	per kWh	800	$ 0.00006	$ 0.05	$0.00006	$ 0.05	$ -	0.00%	$0.00006	$ 0.05	$ -	0.00%
Line Losses on Cost of Power		24.632	$ 0.0889	$ 2.19	$ 0.0889	$ 2.19	$ -	0.00%	$ 0.0889	$ 2.19	$ -	0.00%
Smart Meter Entity Charge	Monthly	1	$ 0.7900	$ 0.79	$ 0.7900	$ 0.79	$ -		$ 0.7900	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 29.69**		**$ 33.16**	**$ 3.47**	**11.69%**		**$ 34.35**	**$ 1.19**	**3.59%**
RTSR - Network	per kWh	824.6320	$ 0.0072	$ 5.94	$ 0.0076	$ 6.27	$ 0.33	5.56%	$ 0.0078	$ 6.43	$ 0.16	2.63%
RTSR - Line and Transformation Connection	per kWh	825	$ 0.0052	$ 4.29	$ 0.0056	$ 4.62	$ 0.33	7.69%	$ 0.0057	$ 4.70	$ 0.08	1.79%
Sub-Total C - Delivery (including Sub-Total B)				**$ 39.91**		**$ 44.04**	**$ 4.13**	**10.35%**		**$ 45.48**	**$ 1.44**	**3.26%**
Wholesale Market Service Charge (WMSC)	per kWh	825	$ 0.0044	$ 3.63	$ 0.0044	$ 3.63	$ -	0.00%	$ 0.0044	$ 3.63	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	825	$ 0.0012	$ 0.99	$ 0.0012	$ 0.99	$ -	0.00%	$ 0.0013	$ 1.07	$ 0.08	8.33%
Standard Supply Service Charge	Monthly	1	$ 0.2500	$ 0.25	$ 0.2500	$ 0.25	$ -	0.00%	$ 0.2500	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	800	$ 0.0070	$ 5.60	$ 0.0070	$ 5.60	$ -	0.00%	$ 0.0070	$ 5.60	$ -	0.00%
TOU - Off Peak	per kWh	512	$ 0.0720	$ 36.86	$ 0.0720	$ 36.86	$ -	0.00%	$ 0.0720	$ 36.86	$ -	0.00%
TOU - Mid Peak	per kWh	144	$ 0.1090	$ 15.70	$ 0.1090	$ 15.70	$ -	0.00%	$ 0.1090	$ 15.70	$ -	0.00%
TOU - On Peak	per kWh	144	$ 0.1290	$ 18.58	$ 0.1290	$ 18.58	$ -	0.00%	$ 0.1290	$ 18.58	$ -	0.00%
Energy - RPP - Tier 1	per kWh	600	$ 0.0830	$ 49.80	$ 0.0830	$ 49.80	$ -	0.00%	$ 0.0830	$ 49.80	$ -	0.00%
Energy - RPP - Tier 2	per kWh	200	$ 0.0970	$ 19.40	$ 0.0970	$ 19.40	$ -	0.00%	$ 0.0970	$ 19.40	$ -	0.00%
Total Bill on TOU (before Taxes)				**$121.52**		**$125.65**	**$ 4.13**	**3.40%**		**$ 127.17**	**$ 1.52**	**1.21%**
HST			13%	$ 15.80	13%	$ 16.33	$ 0.54	3.40%	13%	$ 16.53	$ 0.20	1.21%
Total Bill (including HST)				$137.31		$141.98	$ 4.67	3.40%		$ 143.70	$ 1.72	1.21%
Ontario Clean Energy Benefit				-$ 13.73		-$ 14.20	-$ 0.47	3.42%		-$ 14.37	-$ 0.17	1.20%
Total Bill on TOU (including				**$123.58**		**$127.78**	**$ 4.20**	**3.40%**		**$ 129.33**	**$ 1.55**	**1.21%**
Total Bill on RPP (before Taxes)				**$119.58**		**$123.71**	**$ 4.13**	**3.45%**		**$ 125.23**	**$ 1.52**	**1.23%**
HST			13%	$ 15.55	13%	$ 16.08	$ 0.54	3.45%	13%	$ 16.28	$ 0.20	1.23%
Total Bill (including HST)				$135.13		$139.79	$ 4.67	3.45%		$ 141.51	$ 1.72	1.23%
Ontario Clean Energy Benefit				-$ 13.51		-$ 13.98	-$ 0.47	3.48%		-$ 14.15	-$ 0.17	1.22%
Total Bill on RPP (including				**$121.62**		**$125.81**	**$ 4.20**	**3.45%**		**$ 127.36**	**$ 1.55**	**1.23%**
Loss Factor (%)			3.08%		3.08%				3.08%			

	2017 Proposed Rates Rate ($)	2017 Proposed Rates Charge ($)	2017 vs 2016 $ Change	2017 vs 2016 %	2018 Proposed Rates Rate ($)	2018 Proposed Rates Charge ($)	2018 vs 2017 $ Change	2018 vs 2017 %	2019 Proposed Rates Rate ($)	2019 Proposed Rates Charge ($)	2019 vs 2018 $ Change	2019 vs 2018 %
Monthly Service Charge	$14.9200	$ 14.92	$ -	0.00%	$14.9200	$ 14.92	$ -	0.00%	$14.9200	$ 14.92	$ -	0.00%
Smart Meter Rate Adder		$ -	$ -			$ -	$ -			$ -	$ -	
Smart Meter Incremental Revenue	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of Green Energy Act	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	$ 0.0214	$ 17.12	$ 0.72	4.39%	$ 0.0221	$ 17.68	$ 0.56	3.27%	$ 0.0235	$ 18.80	$ 1.12	6.33%
Smart Meter Disposition Rider		$ -	$ -			$ -	$ -			$ -	$ -	
LRAM & SSM Rate Rider		$ -	$ -			$ -	$ -			$ -	$ -	
Rate Rider for Tax Change	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)		$ 32.04	**$ 0.72**	**2.30%**		$ 32.60	**$ 0.56**	**1.75%**		$ 33.72	**$ 1.12**	**3.44%**
Deferral/Variance Account	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Global Adjustment Sub-Account	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
1595	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Low Voltage Service Charge	$0.00006	$ 0.05	$ -	0.00%	$0.00006	$ 0.05	$ -	0.00%	$0.00006	$ 0.05	-$ 0.00	-0.08%
Line Losses on Cost of Power	$ 0.0889	$ 2.19	$ -	0.00%	$ 0.0889	$ 2.19	$ -	0.00%	$ 0.0889	$ 2.19	$ -	0.00%
Smart Meter Entity Charge	$ 0.7900	$ 0.79	$ -		$ 0.7900	$ 0.79	$ -		$ -	$ -	-$ 0.79	
Sub-Total B - Distribution (includes Sub-Total A)		**$ 35.07**	**$ 0.72**	**2.10%**		**$ 35.63**	**$ 0.56**	**1.60%**		**$ 35.96**	**$ 0.33**	**0.93%**
RTSR - Network	$ 0.0081	$ 6.68	$ 0.25	3.85%	$ 0.0084	$ 6.93	$ 0.25	3.70%	$ 0.0086	$ 7.09	$ 0.16	2.38%
RTSR - Line and Transformation Connection	$ 0.0058	$ 4.78	$ 0.08	1.75%	$ 0.0060	$ 4.95	$ 0.16	3.45%	$ 0.0061	$ 5.03	$ 0.08	1.67%
Sub-Total C - Delivery (including Sub-Total B)		**$ 46.53**	**$ 1.05**	**2.31%**		**$ 47.50**	**$ 0.97**	**2.09%**		**$ 48.08**	**$ 0.58**	**1.22%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	$ 3.63	$ -	0.00%	$ 0.0044	$ 3.63	$ -	0.00%	$ 0.0044	$ 3.63	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	$ 1.07	$ -	0.00%	$ 0.0013	$ 1.07	$ -	0.00%	$ 0.0013	$ 1.07	$ -	0.00%
Standard Supply Service Charge	$ 0.2500	$ 0.25	$ -	0.00%	$ 0.2500	$ 0.25	$ -	0.00%	$ 0.2500	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	$ 0.0070	$ 5.60	$ -	0.00%	$ 0.0070	$ 5.60	$ -	0.00%	$ 0.0070	$ 5.60	$ -	0.00%
TOU - Off Peak	$ 0.0720	$ 36.86	$ -	0.00%	$ 0.0720	$ 36.86	$ -	0.00%	$ 0.0720	$ 36.86	$ -	0.00%
TOU - Mid Peak	$ 0.1090	$ 15.70	$ -	0.00%	$ 0.1090	$ 15.70	$ -	0.00%	$ 0.1090	$ 15.70	$ -	0.00%
TOU - On Peak	$ 0.1290	$ 18.58	$ -	0.00%	$ 0.1290	$ 18.58	$ -	0.00%	$ 0.1290	$ 18.58	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0830	$ 49.80	$ -	0.00%	$ 0.0830	$ 49.80	$ -	0.00%	$ 0.0830	$ 49.80	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0970	$ 19.40	$ -	0.00%	$ 0.0970	$ 19.40	$ -	0.00%	$ 0.0970	$ 19.40	$ -	0.00%
Total Bill on TOU (before Taxes)		**$ 128.22**	**$ 1.05**	**0.83%**		**$ 129.19**	**$ 0.97**	**0.76%**		**$ 129.77**	**$ 0.58**	**0.45%**
HST	13%	$ 16.67	$ 0.14	0.83%	13%	$ 16.79	$ 0.13	0.76%	13%	$ 16.87	$ 0.08	0.45%
Total Bill (including HST)		$ 144.89	$ 1.19	0.83%		$ 145.98	$ 1.10	0.76%		$ 146.64	$ 0.65	0.45%
Ontario Clean Energy Benefit		-$ 14.49	-$ 0.12	0.84%		-$ 14.60	-$ 0.11	0.76%		-$ 14.66	-$ 0.06	0.41%
Total Bill on TOU (including		**$ 130.40**	**$ 1.07**	**0.82%**		**$ 131.38**	**$ 0.99**	**0.76%**		**$ 131.98**	**$ 0.59**	**0.45%**
Total Bill on RPP (before Taxes)		**$ 126.28**	**$ 1.05**	**0.84%**		**$ 127.25**	**$ 0.97**	**0.77%**		**$ 127.83**	**$ 0.58**	**0.45%**
HST	13%	$ 16.42	$ 0.14	0.84%	13%	$ 16.54	$ 0.13	0.77%	13%	$ 16.62	$ 0.08	0.45%
Total Bill (including HST)		$ 142.70	$ 1.19	0.84%		$ 143.80	$ 1.10	0.77%		$ 144.45	$ 0.65	0.45%
Ontario Clean Energy Benefit		-$ 14.27	-$ 0.12	0.85%		-$ 14.38	-$ 0.11	0.77%		-$ 14.44	-$ 0.06	0.42%
Total Bill on RPP (including		**$ 128.43**	**$ 1.07**	**0.84%**		**$ 129.42**	**$ 0.99**	**0.77%**		**$ 130.01**	**$ 0.59**	**0.46%**
Loss Factor (%)	3.08%				3.08%				3.08%			

Table 6: Residential Bill Impacts at 1,000 kWh (Revised Table 8-48)

	Charge Unit	Volume	2014 Rates Rate ($)	2014 Rates Charge ($)	2015 Proposed Rates Rate ($)	2015 Proposed Rates Charge ($)	2015 vs 2014 $ Change	2015 vs 2014 % Change
Monthly Service Charge	Monthly	1	$ 14.9200	$ 14.92	$14.9200	$ 14.92	$ -	0.00%
Smart Meter Rate Adder	Monthly	1		$ -		$ -	$ -	
Smart Meter Incremental Revenue	Monthly	1	$ 1.4700	$ 1.47	$ -	$ -	-$ 1.47	-100.00%
Recovery of Green Energy Act	Monthly	1	$ 0.0400	$ 0.04	$ -	$ -	-$ 0.04	-100.00%
Distribution Volumetric Rate	per kWh	1000	$ 0.0147	$ 14.70	$ 0.0185	$ 18.50	$ 3.80	25.85%
Smart Meter Disposition Rider	Monthly	1	$ -	$ -	$ 0.0100	$ 0.01	$ 0.01	
LRAM & SSM Rate Rider	per kWh	1000		$ -	-$ 0.0001	-$ 0.10	-$ 0.10	
Rate Rider for Tax Change	per kWh	1000	-$ 0.0001	-$ 0.10	$ -	$ -	$ 0.10	-100.00%
Sub-Total A (excluding pass through)				$ 31.03		$ 33.33	**$ 2.30**	**7.41%**
Deferral/Variance Account	per kWh	1000	-$ 0.0016	-$ 1.60	-$ 0.0007	-$ 0.70	$ 0.90	-56.25%
Global Adjustment Sub-Account	per kWh	1000	-$ 0.0002	-$ 0.21	$ 0.0012	$ 1.20	$ 1.41	-660.66%
1595	per kWh	1000	$ -	$ -	$ 0.0001	$ 0.10	$ 0.10	
Low Voltage Service Charge	per kWh	1000	$ 0.00006	$ 0.06	$0.00006	$ 0.06	$ -	0.00%
Line Losses on Cost of Power		30.79	$ 0.0889	$ 2.74	$ 0.0889	$ 2.74	$ -	0.00%
Smart Meter Entity Charge	Monthly	1	$ 0.7900	$ 0.79	$ 0.7900	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 32.80**		**$ 37.52**	**$ 4.71**	**14.37%**
RTSR - Network	per kWh	1031	$ 0.0072	$ 7.42	$ 0.0076	$ 7.83	$ 0.41	5.56%
RTSR - Line and Transformation Connection	per kWh	1031	$ 0.0052	$ 5.36	$ 0.0056	$ 5.77	$ 0.41	7.69%
Sub-Total C - Delivery (including Sub-Total B)				**$ 45.59**		**$ 51.12**	**$ 5.54**	**12.15%**
Wholesale Market Service Charge (WMSC)	per kWh	1031	$ 0.0044	$ 4.54	$ 0.0044	$ 4.54	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	1031	$ 0.0012	$ 1.24	$ 0.0012	$ 1.24	$ -	0.00%
Standard Supply Service Charge	Monthly	1	$ 0.2500	$ 0.25	$ 0.2500	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	1000	$ 0.0070	$ 7.00	$ 0.0070	$ 7.00	$ -	0.00%
TOU - Off Peak	per kWh	640	$ 0.0720	$ 46.08	$ 0.0720	$ 46.08	$ -	0.00%
TOU - Mid Peak	per kWh	180	$ 0.1090	$ 19.62	$ 0.1090	$ 19.62	$ -	0.00%
TOU - On Peak	per kWh	180	$ 0.1290	$ 23.22	$ 0.1290	$ 23.22	$ -	0.00%
Energy - RPP - Tier 1	per kWh	600	$ 0.0830	$ 49.80	$ 0.0830	$ 49.80	$ -	0.00%
Energy - RPP - Tier 2	per kWh	400	$ 0.0970	$ 38.80	$ 0.0970	$ 38.80	$ -	0.00%
Total Bill on TOU (before Taxes)				**$147.53**		**$153.07**	**$ 5.54**	**3.75%**
HST			13%	$ 19.18	13%	$ 19.90	$ 0.72	3.75%
Total Bill (including HST)				$166.71		$172.97	$ 6.26	3.75%
Ontario Clean Energy Benefit				-$ 16.67		-$ 17.30	-$ 0.63	3.78%
Total Bill on TOU (including				**$150.04**		**$155.67**	**$ 5.63**	**3.75%**
Total Bill on RPP (before Taxes)				**$147.21**		**$152.75**	**$ 5.54**	**3.76%**
HST			13%	$ 19.14	13%	$ 19.86	$ 0.72	3.76%
Total Bill (including HST)				$166.35		$172.60	$ 6.26	3.76%
Ontario Clean Energy Benefit				-$ 16.63		-$ 17.26	-$ 0.63	3.79%
Total Bill on RPP (including				**$149.72**		**$155.34**	**$ 5.63**	**3.76%**
Loss Factor (%)			3.08%		3.08%			

	2016 Proposed Rates Rate ($)	2016 Proposed Rates Charge ($)	2016 vs 2015 $ Change	2016 vs 2015 %	2017 Proposed Rates Rate ($)	2017 Proposed Rates Charge ($)	2017 vs 2016 $ Change	2017 vs 2016 %
Monthly Service Charge	$14.9200	$ 14.92	$ -	0.00%	$14.9200	$ 14.92	$ -	0.00%
Smart Meter Rate Adder		$ -	$ -			$ -	$ -	
Smart Meter Incremental Revenue	$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of Green Energy Act	$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	$ 0.0205	$ 20.50	$ 2.00	10.81%	$ 0.0214	$ 21.40	$ 0.90	4.39%
Smart Meter Disposition Rider		$ -	-$ 0.01	-100.00%		$ -	$ -	
LRAM & SSM Rate Rider		$ -	$ 0.10	-100.00%		$ -	$ -	
Rate Rider for Tax Change	$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)		$ 35.42	**$ 2.09**	**6.27%**		$ 36.32	**$ 0.90**	**2.54%**
Deferral/Variance Account	$ -	$ -	$ 0.70	-100.00%	$ -	$ -	$ -	
Global Adjustment Sub-Account	$ -	$ -	-$ 1.20	-100.00%	$ -	$ -	$ -	
1595	$ -	$ -	-$ 0.10	-100.00%	$ -	$ -	$ -	
Low Voltage Service Charge	$0.00006	$ 0.06	$ -	0.00%	$0.00006	$ 0.06	$ -	0.00%
Line Losses on Cost of Power	$ 0.0889	$ 2.74	$ -	0.00%	$ 0.0889	$ 2.74	$ -	0.00%
Smart Meter Entity Charge	$ 0.7900	$ 0.79	$ -		$ 0.7900	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)		**$ 39.01**	**$ 1.49**	**3.97%**		**$ 39.91**	**$ 0.90**	**2.31%**
RTSR - Network	$ 0.0078	$ 8.04	$ 0.21	2.63%	$ 0.0081	$ 8.35	$ 0.31	3.85%
RTSR - Line and Transformation Connection	$ 0.0057	$ 5.88	$ 0.10	1.79%	$ 0.0058	$ 5.98	$ 0.10	1.75%
Sub-Total C - Delivery (including Sub-Total B)		**$ 52.92**	**$ 1.80**	**3.52%**		**$ 54.24**	**$ 1.31**	**2.48%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	$ 4.54	$ -	0.00%	$ 0.0044	$ 4.54	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	$ 1.34	$ 0.10	8.33%	$ 0.0013	$ 1.34	$ -	0.00%
Standard Supply Service Charge	$ 0.2500	$ 0.25	$ -	0.00%	$ 0.2500	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	$ 0.0070	$ 7.00	$ -	0.00%	$ 0.0070	$ 7.00	$ -	0.00%
TOU - Off Peak	$ 0.0720	$ 46.08	$ -	0.00%	$ 0.0720	$ 46.08	$ -	0.00%
TOU - Mid Peak	$ 0.1090	$ 19.62	$ -	0.00%	$ 0.1090	$ 19.62	$ -	0.00%
TOU - On Peak	$ 0.1290	$ 23.22	$ -	0.00%	$ 0.1290	$ 23.22	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0830	$ 49.80	$ -	0.00%	$ 0.0830	$ 49.80	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0970	$ 38.80	$ -	0.00%	$ 0.0970	$ 38.80	$ -	0.00%
			$ -				$ -	
Total Bill on TOU (before Taxes)		**$ 154.97**	**$ 1.90**	**1.24%**		**$ 156.28**	**$ 1.31**	**0.85%**
HST	13%	$ 20.15	$ 0.25	1.24%	13%	$ 20.32	$ 0.17	0.85%
Total Bill (including HST)		$ 175.11	$ 2.15	1.24%		$ 176.60	$ 1.48	0.85%
Ontario Clean Energy Benefit		-$ 17.51	-$ 0.21	1.21%		-$ 17.66	-$ 0.15	0.86%
Total Bill on TOU (including		**$ 157.60**	**$ 1.94**	**1.25%**		**$ 158.94**	**$ 1.33**	**0.85%**
			$ -				$ -	
Total Bill on RPP (before Taxes)		**$ 154.65**	**$ 1.90**	**1.25%**		**$ 155.96**	**$ 1.31**	**0.85%**
HST	13%	$ 20.10	$ 0.25	1.25%	13%	$ 20.27	$ 0.17	0.85%
Total Bill (including HST)		$ 174.75	$ 2.15	1.25%		$ 176.24	$ 1.48	0.85%
Ontario Clean Energy Benefit		-$ 17.48	-$ 0.22	1.27%		-$ 17.62	-$ 0.14	0.80%
Total Bill on RPP (including		**$ 157.27**	**$ 1.93**	**1.24%**		**$ 158.62**	**$ 1.34**	**0.85%**
Loss Factor (%)	3.08%				3.08%			

	2018 Proposed Rates Rate ($)	2018 Proposed Rates Charge ($)	2018 vs 2017 $ Change	2018 vs 2017 %	2019 Proposed Rates Rate ($)	2019 Proposed Rates Charge ($)	2019 vs 2018 $ Change	2019 vs 2018 %
Monthly Service Charge	$14.9200	$ 14.92	$ -	0.00%	$14.9200	$ 14.92	$ -	0.00%
Smart Meter Rate Adder		$ -	$ -			$ -	$ -	
Smart Meter Incremental Revenue	$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of Green Energy Act	$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	$ 0.0221	$ 22.10	$ 0.70	3.27%	$ 0.0235	$ 23.50	$ 1.40	6.33%
Smart Meter Disposition Rider		$ -	$ -			$ -	$ -	
LRAM & SSM Rate Rider		$ -	$ -			$ -	$ -	
Rate Rider for Tax Change	$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)		$ 37.02	**$ 0.70**	**1.93%**		$ 38.42	**$ 1.40**	**3.78%**
Deferral/Variance Account	$ -	$ -	$ -		$ -	$ -	$ -	
Global Adjustment Sub-Account	$ -	$ -	$ -		$ -	$ -	$ -	
1595	$ -	$ -	$ -		$ -	$ -	$ -	
Low Voltage Service Charge	$0.00006	$ 0.06	$ -	0.00%	$0.00006	$ 0.06	-$ 0.00	-0.08%
Line Losses on Cost of Power	$ 0.0889	$ 2.74	$ -	0.00%	$ 0.0889	$ 2.74	$ -	0.00%
Smart Meter Entity Charge	$ 0.7900	$ 0.79	$ -		$ -	$ -	-$ 0.79	
Sub-Total B - Distribution (includes Sub-Total A)		**$ 40.61**	**$ 0.70**	**1.75%**		**$ 41.22**	**$ 0.61**	**1.50%**
RTSR - Network	$ 0.0084	$ 8.66	$ 0.31	3.70%	$ 0.0086	$ 8.86	$ 0.21	2.38%
RTSR - Line and Transformation Connection	$ 0.0060	$ 6.18	$ 0.21	3.45%	$ 0.0061	$ 6.29	$ 0.10	1.67%
Sub-Total C - Delivery (including Sub-Total B)		**$ 55.45**	**$ 1.22**	**2.24%**		**$ 56.37**	**$ 0.92**	**1.66%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	$ 4.54	$ -	0.00%	$ 0.0044	$ 4.54	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	$ 1.34	$ -	0.00%	$ 0.0013	$ 1.34	$ -	0.00%
Standard Supply Service Charge	$ 0.2500	$ 0.25	$ -	0.00%	$ 0.2500	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	$ 0.0070	$ 7.00	$ -	0.00%	$ 0.0070	$ 7.00	$ -	0.00%
TOU - Off Peak	$ 0.0720	$ 46.08	$ -	0.00%	$ 0.0720	$ 46.08	$ -	0.00%
TOU - Mid Peak	$ 0.1090	$ 19.62	$ -	0.00%	$ 0.1090	$ 19.62	$ -	0.00%
TOU - On Peak	$ 0.1290	$ 23.22	$ -	0.00%	$ 0.1290	$ 23.22	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0830	$ 49.80	$ -	0.00%	$ 0.0830	$ 49.80	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0970	$ 38.80	$ -	0.00%	$ 0.0970	$ 38.80	$ -	0.00%
			$ -				$ -	
Total Bill on TOU (before Taxes)		**$ 157.50**	**$ 1.22**	**0.78%**		**$ 158.42**	**$ 0.92**	**0.58%**
HST	13%	$ 20.47	$ 0.16	0.78%	13%	$ 20.59	$ 0.12	0.58%
Total Bill (including HST)		$ 177.97	$ 1.37	0.78%		$ 179.01	$ 1.04	0.58%
Ontario Clean Energy Benefit		-$ 17.80	-$ 0.14	0.79%		-$ 17.90	-$ 0.10	0.56%
Total Bill on TOU (including		**$ 160.17**	**$ 1.23**	**0.78%**		**$ 161.11**	**$ 0.94**	**0.59%**
			$ -				$ -	
Total Bill on RPP (before Taxes)		**$ 157.18**	**$ 1.22**	**0.78%**		**$ 158.10**	**$ 0.92**	**0.58%**
HST	13%	$ 20.43	$ 0.16	0.78%	13%	$ 20.55	$ 0.12	0.58%
Total Bill (including HST)		$ 177.61	$ 1.37	0.78%		$ 178.65	$ 1.04	0.58%
Ontario Clean Energy Benefit		-$ 17.76	-$ 0.14	0.79%		-$ 17.86	-$ 0.10	0.56%
Total Bill on RPP (including		**$ 159.85**	**$ 1.23**	**0.78%**		**$ 160.79**	**$ 0.94**	**0.59%**
Loss Factor (%)	3.08%				3.08%			

Table 7: Residential Bill Impacts at 1,500 kWh (Revised Table 8-49)

	Charge Unit	Volume	2014 Rates		2015 Proposed Rates		2015 vs 2014		2016 Proposed Rates		2016 vs 2015	
			Rate ($)	Charge ($)	Rate ($)	Charge ($)	$ Change	% Change	Rate ($)	Charge ($)	$ Change	%
Monthly Service Charge	Monthly	1	$ 14.9200	$ 14.92	$14.9200	$ 14.92	$ -	0.00%	$14.9200	$ 14.92	$ -	0.00%
Smart Meter Rate Adder	Monthly	1		$ -		$ -	$ -			$ -	$ -	
Smart Meter Incremental Revenue	Monthly	1	$ 1.4700	$ 1.47	$ -	$ -	-$ 1.47	-100.00%	$ -	$ -	$ -	
Recovery of Green Energy Act	Monthly	1	$ 0.0400	$ 0.04	$ -	$ -	-$ 0.04	-100.00%	$ -	$ -	$ -	
Distribution Volumetric Rate	per kWh	1500	$ 0.0147	$ 22.05	$ 0.0185	$ 27.75	$ 5.70	25.85%	$ 0.0205	$ 30.75	$ 3.00	10.81%
Smart Meter Disposition Rider	Monthly	1	$ -	$ -	$ 0.0100	$ 0.01	$ 0.01			$ -	-$ 0.01	-100.00%
LRAM & SSM Rate Rider	per kWh	1500		$ -	-$ 0.0001	-$ 0.15	-$ 0.15			$ -	$ 0.15	-100.00%
Rate Rider for Tax Change	per kWh	1500	-$ 0.0001	-$ 0.15	$ -	$ -	$ 0.15	-100.00%	$ -	$ -	$ -	
Sub-Total A (excluding pass through)				$ 38.33		$ 42.53	**$ 4.20**	**10.96%**		$ 45.67	**$ 3.14**	**7.38%**
Deferral/Variance Account	per kWh	1500	-$ 0.0016	-$ 2.40	-$ 0.0007	-$ 1.05	$ 1.35	-56.25%	$ -	$ -	$ 1.05	-100.00%
Global Adjustment Sub-Account	per kWh	1500	-$ 0.0002	-$ 0.32	$ 0.0012	$ 1.80	$ 2.12	-660.66%	$ -	$ -	-$ 1.80	-100.00%
1595	per kWh	1500	$ -	$ -	$ 0.0001	$ 0.15	$ 0.15		$ -	$ -	-$ 0.15	-100.00%
Low Voltage Service Charge	per kWh	1500	$ 0.00006	$ 0.09	$0.00006	$ 0.09	$ -	0.00%	$0.00006	$ 0.09	$ -	0.00%
Line Losses on Cost of Power		46.185	$ 0.0889	$ 4.11	$ 0.0889	$ 4.11	$ -	0.00%	$ 0.0889	$ 4.11	$ -	0.00%
Smart Meter Entity Charge	Monthly	1	$ 0.7900	$ 0.79	$ 0.7900	$ 0.79	$ -		$ 0.7900	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 40.60**		**$ 48.42**	**$ 7.82**	**19.27%**		**$ 50.66**	**$ 2.24**	**4.63%**
RTSR - Network	per kWh	1546	$ 0.0072	$ 11.13	$ 0.0076	$ 11.75	$ 0.62	5.56%	$ 0.0078	$ 12.06	$ 0.31	2.63%
RTSR - Line and Transformation Connection	per kWh	1546	$ 0.0052	$ 8.04	$ 0.0056	$ 8.66	$ 0.62	7.69%	$ 0.0057	$ 8.81	$ 0.15	1.79%
Sub-Total C - Delivery (including Sub-Total B)				**$ 59.77**		**$ 68.83**	**$ 9.06**	**15.16%**		**$ 71.53**	**$ 2.70**	**3.93%**
Wholesale Market Service Charge (WMSC)	per kWh	1546	$ 0.0044	$ 6.80	$ 0.0044	$ 6.80	$ -	0.00%	$ 0.0044	$ 6.80	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	1546	$ 0.0012	$ 1.86	$ 0.0012	$ 1.86	$ -	0.00%	$ 0.0013	$ 2.01	$ 0.15	8.33%
Standard Supply Service Charge	Monthly	1	$ 0.2500	$ 0.25	$ 0.2500	$ 0.25	$ -	0.00%	$ 0.2500	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	1500	$ 0.0070	$ 10.50	$ 0.0070	$ 10.50	$ -	0.00%	$ 0.0070	$ 10.50	$ -	0.00%
TOU - Off Peak	per kWh	960	$ 0.0720	$ 69.12	$ 0.0720	$ 69.12	$ -	0.00%	$ 0.0720	$ 69.12	$ -	0.00%
TOU - Mid Peak	per kWh	270	$ 0.1090	$ 29.43	$ 0.1090	$ 29.43	$ -	0.00%	$ 0.1090	$ 29.43	$ -	0.00%
TOU - On Peak	per kWh	270	$ 0.1290	$ 34.83	$ 0.1290	$ 34.83	$ -	0.00%	$ 0.1290	$ 34.83	$ -	0.00%
Energy - RPP - Tier 1	per kWh	600	$ 0.0830	$ 49.80	$ 0.0830	$ 49.80	$ -	0.00%	$ 0.0830	$ 49.80	$ -	0.00%
Energy - RPP - Tier 2	per kWh	900	$ 0.0970	$ 87.30	$ 0.0970	$ 87.30	$ -	0.00%	$ 0.0970	$ 87.30	$ -	0.00%
											$ -	
Total Bill on TOU (before Taxes)				**$212.56**		**$221.62**	**$ 9.06**	**4.26%**		**$ 224.47**	**$ 2.86**	**1.29%**
HST			13%	$ 27.63	13%	$ 28.81	$ 1.18	4.26%	13%	$ 29.18	$ 0.37	1.29%
Total Bill (including HST)				$240.19		$250.43	$ 10.24	4.26%		$ 253.66	$ 3.23	1.29%
Ontario Clean Energy Benefit				-$ 24.02		-$ 25.04	-$ 1.02	4.25%		-$ 25.37	-$ 0.33	1.32%
Total Bill on TOU (including				**$216.17**		**$225.39**	**$ 9.22**	**4.26%**		**$ 228.29**	**$ 2.90**	**1.29%**
											$ -	
Total Bill on RPP (before Taxes)				**$216.28**		**$225.34**	**$ 9.06**	**4.19%**		**$ 228.19**	**$ 2.86**	**1.27%**
HST			13%	$ 28.12	13%	$ 29.29	$ 1.18	4.19%	13%	$ 29.67	$ 0.37	1.27%
Total Bill (including HST)				$244.39		$254.63	$ 10.24	4.19%		$ 257.86	$ 3.23	1.27%
Ontario Clean Energy Benefit				-$ 24.44		-$ 25.46	-$ 1.02	4.17%		-$ 25.79	-$ 0.33	1.30%
Total Bill on RPP (including				**$219.95**		**$229.17**	**$ 9.22**	**4.19%**		**$ 232.07**	**$ 2.90**	**1.27%**
Loss Factor (%)			3.08%		3.08%				3.08%			

	2017 Proposed Rates		2017 vs 2016		2018 Proposed Rates		2018 vs 2017		2019 Proposed Rates		2019 vs 2018	
	Rate ($)	Charge ($)	$ Change	%	Rate ($)	Charge ($)	$ Change	%	Rate ($)	Charge ($)	$ Change	%
Monthly Service Charge	$14.9200	$ 14.92	$ -	0.00%	$14.9200	$ 14.92	$ -	0.00%	$14.9200	$ 14.92	$ -	0.00%
Smart Meter Rate Adder		$ -	$ -			$ -	$ -			$ -	$ -	
Smart Meter Incremental Revenue	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of Green Energy Act	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	$ 0.0214	$ 32.10	$ 1.35	4.39%	$ 0.0221	$ 33.15	$ 1.05	3.27%	$ 0.0235	$ 35.25	$ 2.10	6.33%
Smart Meter Disposition Rider		$ -	$ -			$ -	$ -			$ -	$ -	
LRAM & SSM Rate Rider		$ -	$ -			$ -	$ -			$ -	$ -	
Rate Rider for Tax Change	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)		$ 47.02	**$ 1.35**	**2.96%**		$ 48.07	**$ 1.05**	**2.23%**		$ 50.17	**$ 2.10**	**4.37%**
Deferral/Variance Account	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Global Adjustment Sub-Account	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
1595	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Low Voltage Service Charge	$0.00006	$ 0.09	$ -	0.00%	$0.00006	$ 0.09	$ -	0.00%	$0.00006	$ 0.09	-$ 0.00	-0.08%
Line Losses on Cost of Power	$ 0.0889	$ 4.11	$ -	0.00%	$ 0.0889	$ 4.11	$ -	0.00%	$ 0.0889	$ 4.11	$ -	0.00%
Smart Meter Entity Charge	$ 0.7900	$ 0.79	$ -		$ 0.7900	$ 0.79	$ -		$ -	$ -	-$ 0.79	
Sub-Total B - Distribution (includes Sub-Total A)		**$ 52.01**	**$ 1.35**	**2.66%**		**$ 53.06**	**$ 1.05**	**2.02%**		**$ 54.37**	**$ 1.31**	**2.47%**
RTSR - Network	$ 0.0081	$ 12.52	$ 0.46	3.85%	$ 0.0084	$ 12.99	$ 0.46	3.70%	$ 0.0086	$ 13.30	$ 0.31	2.38%
RTSR - Line and Transformation Connection	$ 0.0058	$ 8.97	$ 0.15	1.75%	$ 0.0060	$ 9.28	$ 0.31	3.45%	$ 0.0061	$ 9.43	$ 0.15	1.67%
Sub-Total C - Delivery (including Sub-Total B)		**$ 73.50**	**$ 1.97**	**2.75%**		**$ 75.32**	**$ 1.82**	**2.48%**		**$ 77.10**	**$ 1.77**	**2.35%**
Wholesale Market Service Charge (WMSC)	$ 0.0044	$ 6.80	$ -	0.00%	$ 0.0044	$ 6.80	$ -	0.00%	$ 0.0044	$ 6.80	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	$ 2.01	$ -	0.00%	$ 0.0013	$ 2.01	$ -	0.00%	$ 0.0013	$ 2.01	$ -	0.00%
Standard Supply Service Charge	$ 0.2500	$ 0.25	$ -	0.00%	$ 0.2500	$ 0.25	$ -	0.00%	$ 0.2500	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	$ 0.0070	$ 10.50	$ -	0.00%	$ 0.0070	$ 10.50	$ -	0.00%	$ 0.0070	$ 10.50	$ -	0.00%
TOU - Off Peak	$ 0.0720	$ 69.12	$ -	0.00%	$ 0.0720	$ 69.12	$ -	0.00%	$ 0.0720	$ 69.12	$ -	0.00%
TOU - Mid Peak	$ 0.1090	$ 29.43	$ -	0.00%	$ 0.1090	$ 29.43	$ -	0.00%	$ 0.1090	$ 29.43	$ -	0.00%
TOU - On Peak	$ 0.1290	$ 34.83	$ -	0.00%	$ 0.1290	$ 34.83	$ -	0.00%	$ 0.1290	$ 34.83	$ -	0.00%
Energy - RPP - Tier 1	$ 0.0830	$ 49.80	$ -	0.00%	$ 0.0830	$ 49.80	$ -	0.00%	$ 0.0830	$ 49.80	$ -	0.00%
Energy - RPP - Tier 2	$ 0.0970	$ 87.30	$ -	0.00%	$ 0.0970	$ 87.30	$ -	0.00%	$ 0.0970	$ 87.30	$ -	0.00%
			$ -				$ -				$ -	
Total Bill on TOU (before Taxes)		**$ 226.44**	**$ 1.97**	**0.88%**		**$ 228.27**	**$ 1.82**	**0.81%**		**$ 230.04**	**$ 1.77**	**0.78%**
HST	13%	$ 29.44	$ 0.26	0.88%	13%	$ 29.67	$ 0.24	0.81%	13%	$ 29.91	$ 0.23	0.78%
Total Bill (including HST)		$ 255.88	$ 2.22	0.88%		$ 257.94	$ 2.06	0.81%		$ 259.94	$ 2.00	0.78%
Ontario Clean Energy Benefit		-$ 25.59	-$ 0.22	0.87%		-$ 25.79	-$ 0.20	0.78%		-$ 25.99	-$ 0.20	0.78%
Total Bill on TOU (including		**$ 230.29**	**$ 2.00**	**0.88%**		**$ 232.15**	**$ 1.86**	**0.81%**		**$ 233.95**	**$ 1.80**	**0.78%**
			$ -				$ -				$ -	
Total Bill on RPP (before Taxes)		**$ 230.16**	**$ 1.97**	**0.86%**		**$ 231.99**	**$ 1.82**	**0.79%**		**$ 233.76**	**$ 1.77**	**0.76%**
HST	13%	$ 29.92	$ 0.26	0.86%	13%	$ 30.16	$ 0.24	0.79%	13%	$ 30.39	$ 0.23	0.76%
Total Bill (including HST)		$ 260.08	$ 2.22	0.86%		$ 262.14	$ 2.06	0.79%		$ 264.15	$ 2.00	0.76%
Ontario Clean Energy Benefit		-$ 26.01	-$ 0.22	0.85%		-$ 26.21	-$ 0.20	0.77%		-$ 26.41	-$ 0.20	0.76%
Total Bill on RPP (including		**$ 234.07**	**$ 2.00**	**0.86%**		**$ 235.93**	**$ 1.86**	**0.79%**		**$ 237.74**	**$ 1.80**	**0.76%**
Loss Factor (%)	3.08%				3.08%				3.08%			

Table 8: Residential Bill Impacts at 2,000 kWh (Revised Table 8-50)

			2014 Rates		2015 Proposed Rates		2015 vs 2014		2016 Proposed Rates		2016 vs 2015		2017 Proposed Rates		2017 vs 2016		2018 Proposed Rates		2018 vs 2017		2019 Proposed Rates		2019 vs 2018	
	Charge Unit	Volume	Rate ($)	Charge ($)	Rate ($)	Charge ($)	$ Change	% Change	Rate ($)	Charge ($)	$ Change	%	Rate ($)	Charge ($)	$ Change	%	Rate ($)	Charge ($)	$ Change	%	Rate ($)	Charge ($)	$ Change	%
Monthly Service Charge	Monthly	1	$ 14.9200	$ 14.92	$14.9200	$ 14.92	$ -	0.00%	$14.9200	$ 14.92	$ -	0.00%	$14.9200	$ 14.92	$ -	0.00%	$14.9200	$ 14.92	$ -	0.00%	$14.9200	$ 14.92	$ -	0.00%
Smart Meter Rate Adder	Monthly	1		$ -		$ -	$ -			$ -	$ -			$ -	$ -			$ -	$ -			$ -	$ -	
Smart Meter Incremental Revenue	Monthly	1	$ 1.4700	$ 1.47	$ -	$ -	-$ 1.47	-100.00%	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Recovery of Green Energy Act	Monthly	1	$ 0.0400	$ 0.04	$ -	$ -	-$ 0.04	-100.00%	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Distribution Volumetric Rate	per kWh	2000	$ 0.0147	$ 29.40	$ 0.0185	$ 37.00	$ 7.60	25.85%	$ 0.0205	$ 41.00	$ 4.00	10.81%	$ 0.0214	$ 42.80	$ 1.80	4.39%	$ 0.0221	$ 44.20	$ 1.40	3.27%	$ 0.0235	$ 47.00	$ 2.80	6.33%
Smart Meter Disposition Rider	Monthly	1	$ -	$ -	$ 0.0100	$ 0.01	$ 0.01			$ -	-$ 0.01	-100.00%		$ -	$ -			$ -	$ -			$ -	$ -	
LRAM & SSM Rate Rider	per kWh	2000		$ -	-$ 0.0001	-$ 0.20	-$ 0.20			$ -	$ 0.20	-100.00%		$ -	$ -			$ -	$ -			$ -	$ -	
Rate Rider for Tax Change	per kWh	2000	-$ 0.0001	-$ 0.20	$ -	$ -	$ 0.20	-100.00%	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Sub-Total A (excluding pass through)				$ 45.63		$ 51.73	**$ 6.10**	**13.37%**		$ 55.92	**$ 4.19**	**8.10%**		$ 57.72	**$ 1.80**	**3.22%**		$ 59.12	**$ 1.40**	**2.43%**		$ 61.92	**$ 2.80**	**4.74%**
Deferral/Variance Account	per kWh	2000	-$ 0.0016	-$ 3.20	-$ 0.0007	-$ 1.40	$ 1.80	-56.25%	$ -	$ -	$ 1.40	-100.00%	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Global Adjustment Sub-Account	per kWh	2000	-$ 0.0002	-$ 0.43	$ 0.0012	$ 2.40	$ 2.83	-660.66%	$ -	$ -	-$ 2.40	-100.00%	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
1595	per kWh	2000	$ -	$ -	$ 0.0001	$ 0.20	$ 0.20		$ -	$ -	-$ 0.20	-100.00%	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -	
Low Voltage Service Charge	per kWh	2000	$ 0.00006	$ 0.12	$0.00006	$ 0.12	$ -	0.00%	$0.00006	$ 0.12	$ -	0.00%	$0.00006	$ 0.12	$ -	0.00%	$0.00006	$ 0.12	$ -	0.00%	$0.00006	$ 0.12	-$ 0.00	-0.08%
Line Losses on Cost of Power		61.58	$ 0.0889	$ 5.48	$ 0.0889	$ 5.48	$ -	0.00%	$ 0.0889	$ 5.48	$ -	0.00%	$ 0.0889	$ 5.48	$ -	0.00%	$ 0.0889	$ 5.48	$ -	0.00%	$ 0.0889	$ 5.48	$ -	0.00%
Smart Meter Entity Charge	Monthly	1	$ 0.7900	$ 0.79	$ 0.7900	$ 0.79	$ -		$ 0.7900	$ 0.79	$ -		$ 0.7900	$ 0.79	$ -		$ 0.7900	$ 0.79	$ -		$ -	$ -	-$ 0.79	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 48.39**		**$ 59.32**	**$ 10.93**	**22.58%**		**$ 62.31**	**$ 2.99**	**5.04%**		**$ 64.11**	**$ 1.80**	**2.89%**		**$ 65.51**	**$ 1.40**	**2.18%**		**$ 67.52**	**$ 2.01**	**3.07%**
RTSR - Network	per kWh	2062	$ 0.0072	$ 14.84	$ 0.0076	$ 15.67	$ 0.82	5.56%	$ 0.0078	$ 16.08	$ 0.41	2.63%	$ 0.0081	$ 16.70	$ 0.62	3.85%	$ 0.0084	$ 17.32	$ 0.62	3.70%	$ 0.0086	$ 17.73	$ 0.41	2.38%
RTSR - Line and Transformation Connection	per kWh	2062	$ 0.0052	$ 10.72	$ 0.0056	$ 11.54	$ 0.82	7.69%	$ 0.0057	$ 11.75	$ 0.21	1.79%	$ 0.0058	$ 11.96	$ 0.21	1.75%	$ 0.0060	$ 12.37	$ 0.41	3.45%	$ 0.0061	$ 12.58	$ 0.21	1.67%
Sub-Total C - Delivery (including Sub-Total B)				**$ 73.95**		**$ 86.53**	**$ 12.58**	**17.01%**		**$ 90.14**	**$ 3.61**	**4.17%**		**$ 92.76**	**$ 2.62**	**2.91%**		**$ 95.19**	**$ 2.43**	**2.62%**		**$ 97.82**	**$ 2.63**	**2.76%**
Wholesale Market Service Charge (WMSC)	per kWh	2062	$ 0.0044	$ 9.07	$ 0.0044	$ 9.07	$ -	0.00%	$ 0.0044	$ 9.07	$ -	0.00%	$ 0.0044	$ 9.07	$ -	0.00%	$ 0.0044	$ 9.07	$ -	0.00%	$ 0.0044	$ 9.07	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	2062	$ 0.0012	$ 2.47	$ 0.0012	$ 2.47	$ -	0.00%	$ 0.0013	$ 2.68	$ 0.21	8.33%	$ 0.0013	$ 2.68	$ -	0.00%	$ 0.0013	$ 2.68	$ -	0.00%	$ 0.0013	$ 2.68	$ -	0.00%
Standard Supply Service Charge	Monthly	1	$ 0.2500	$ 0.25	$ 0.2500	$ 0.25	$ -	0.00%	$ 0.2500	$ 0.25	$ -	0.00%	$ 0.2500	$ 0.25	$ -	0.00%	$ 0.2500	$ 0.25	$ -	0.00%	$ 0.2500	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	2000	$ 0.0070	$ 14.00	$ 0.0070	$ 14.00	$ -	0.00%	$ 0.0070	$ 14.00	$ -	0.00%	$ 0.0070	$ 14.00	$ -	0.00%	$ 0.0070	$ 14.00	$ -	0.00%	$ 0.0070	$ 14.00	$ -	0.00%
TOU - Off Peak	per kWh	1280	$ 0.0720	$ 92.16	$ 0.0720	$ 92.16	$ -	0.00%	$ 0.0720	$ 92.16	$ -	0.00%	$ 0.0720	$ 92.16	$ -	0.00%	$ 0.0720	$ 92.16	$ -	0.00%	$ 0.0720	$ 92.16	$ -	0.00%
TOU - Mid Peak	per kWh	360	$ 0.1090	$ 39.24	$ 0.1090	$ 39.24	$ -	0.00%	$ 0.1090	$ 39.24	$ -	0.00%	$ 0.1090	$ 39.24	$ -	0.00%	$ 0.1090	$ 39.24	$ -	0.00%	$ 0.1090	$ 39.24	$ -	0.00%
TOU - On Peak	per kWh	360	$ 0.1290	$ 46.44	$ 0.1290	$ 46.44	$ -	0.00%	$ 0.1290	$ 46.44	$ -	0.00%	$ 0.1290	$ 46.44	$ -	0.00%	$ 0.1290	$ 46.44	$ -	0.00%	$ 0.1290	$ 46.44	$ -	0.00%
Energy - RPP - Tier 1	per kWh	600	$ 0.0830	$ 49.80	$ 0.0830	$ 49.80	$ -	0.00%	$ 0.0830	$ 49.80	$ -	0.00%	$ 0.0830	$ 49.80	$ -	0.00%	$ 0.0830	$ 49.80	$ -	0.00%	$ 0.0830	$ 49.80	$ -	0.00%
Energy - RPP - Tier 2	per kWh	1400	$ 0.0970	$135.80	$ 0.0970	$135.80	$ -	0.00%	$ 0.0970	$135.80	$ -	0.00%	$ 0.0970	$135.80	$ -	0.00%	$ 0.0970	$135.80	$ -	0.00%	$ 0.0970	$135.80	$ -	0.00%
											$ -				$ -				$ -				$ -	
Total Bill on TOU (before Taxes)				**$277.59**		**$290.16**	**$ 12.58**	**4.53%**		**$293.98**	**$ 3.81**	**1.31%**		**$296.60**	**$ 2.62**	**0.89%**		**$299.03**	**$ 2.43**	**0.82%**		**$301.66**	**$ 2.63**	**0.88%**
HST			13%	$ 36.09	13%	$ 37.72	$ 1.64	4.53%	13%	$ 38.22	$ 0.50	1.31%	13%	$ 38.56	$ 0.34	0.89%	13%	$ 38.87	$ 0.32	0.82%	13%	$ 39.22	$ 0.34	0.88%
Total Bill (including HST)				$313.67		$327.88	$ 14.21	4.53%		$332.20	$ 4.31	1.31%		$335.16	$ 2.97	0.89%		$337.91	$ 2.75	0.82%		$340.88	$ 2.97	0.88%
Ontario Clean Energy Benefit				-$ 31.37		-$ 32.79	-$ 1.42	4.53%		-$ 33.22	-$ 0.43	1.31%		-$ 33.52	-$ 0.30	0.90%		-$ 33.79	-$ 0.27	0.81%		-$ 34.09	-$ 0.30	0.89%
Total Bill on TOU (including				**$282.30**		**$295.09**	**$ 12.79**	**4.53%**		**$298.98**	**$ 3.88**	**1.32%**		**$301.64**	**$ 2.67**	**0.89%**		**$304.12**	**$ 2.48**	**0.82%**		**$306.79**	**$ 2.67**	**0.88%**
											$ -				$ -				$ -				$ -	
Total Bill on RPP (before Taxes)				**$285.35**		**$297.92**	**$ 12.58**	**4.41%**		**$301.74**	**$ 3.81**	**1.28%**		**$304.36**	**$ 2.62**	**0.87%**		**$306.79**	**$ 2.43**	**0.80%**		**$309.42**	**$ 2.63**	**0.86%**
HST			13%	$ 37.09	13%	$ 38.73	$ 1.64	4.41%	13%	$ 39.23	$ 0.50	1.28%	13%	$ 39.57	$ 0.34	0.87%	13%	$ 39.88	$ 0.32	0.80%	13%	$ 40.22	$ 0.34	0.86%
Total Bill (including HST)				$322.44		$336.65	$ 14.21	4.41%		$340.96	$ 4.31	1.28%		$343.93	$ 2.97	0.87%		$346.68	$ 2.75	0.80%		$349.65	$ 2.97	0.86%
Ontario Clean Energy Benefit				-$ 32.24		-$ 33.67	-$ 1.43	4.44%		-$ 34.10	-$ 0.43	1.28%		-$ 34.39	-$ 0.29	0.85%		-$ 34.67	-$ 0.28	0.81%		-$ 34.96	-$ 0.29	0.84%
Total Bill on RPP (including				**$290.20**		**$302.98**	**$ 12.78**	**4.40%**		**$306.86**	**$ 3.88**	**1.28%**		**$309.54**	**$ 2.68**	**0.87%**		**$312.01**	**$ 2.47**	**0.80%**		**$314.69**	**$ 2.68**	**0.86%**
Loss Factor (%)			3.08%		3.08%				3.08%				3.08%				3.08%				3.08%			

8.0-VECC-59

Reference: E8/T1/S2/pg.12

a) What is the cost of providing the transformer ownership allowance in 2015, by customer class?

b) Where/how is the "cost" recovered? It is noted that the proposed rates for the GS>50 class in 8/T3/S4 are the same as those calculated on pages 8-12 using the base revenue requirement.

Response:

a) The forecast Transformer Ownership Allowance for the 2015 Test Year is $1,533,896 for the GS > 50kW class.

b) The full allowance of $1,533,896 is provided to GS > 50 kW customers based on a rate of $(0.73)/kW.

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8.0-VECC-60

Reference: E8/T1/S4/pg.1

a) What is the basis for Horizon determining there is no need to change any of the retail service charges (i.e. do the current charges adequately cover costs)?

Response:

a) Horizon Utilities has not considered a change to the retail service charges. The current charges do not adequately cover costs. However, in Article 490 of the Accounting Procedures Handbook states that "*The balances in the variance accounts will therefore reflect, on a global basis, whether the approved rates are sufficient to cover the estimated incremental expenses or not. The account balances filed as part of the RRR on a quarterly basis are used by the Board to adjust the approved rates for these services and to monitor for disposition of the variance accounts*."

Horizon Utilities believes that a generic proceeding would be the best avenue to consider changing retail service charges. Horizon Utilities current Retail Service Charges are provided at Exhibit 8, Tab 1, Schedule 4, Table 8-21.

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8.0-VECC-61

Reference: E8/T1/S7/pg.1

a) Please confirm that Paymentus does not handle transactions of more than $275.

b) For customers that do not use their credit card for payments to Horizon, how are such payments made and now are they processed

c) What is the cost to Horizon of processing such payments entirely itself as opposed to the cost of using Paymentus (including the $5.95 transaction fee)?

d) How many payments does Horizon process annually that are less than $275 and what are these payments typically for?

Response:

a. The Paymentus system as implemented for Horizon Utilities does not enable a transaction value greater than $275. Customers may submit multiple transactions.

b. In addition to credit card payments through Paymentus, customers may provide payment by using the drop boxes at Horizon Utilities' locations, make a payment at their financial institutions, or submit their payment by mail. Payment options include cheque, certified cheque, money order, electronically with on-line banking, telepay, or automatic withdrawal with pre-authorized banking. All payments are processed internally by Horizon Utilities staff.

c. Horizon Utilities estimates that it would cost approximately $21.50 per transaction to process credit card payments internally as compared to approximately $6.70 per transaction with the inclusion of the transaction fee and the internal costs related to the provision of Paymentus.

   As indicated in Exhibit 8, Tab 1, Schedule 7, Page 1, the proposed Paymentus Service Charge represents the service fee charged by Paymentus and is a flow through charge that would be collected by Horizon Utilities and remitted directly to Paymentus.

d. Horizon Utilities processes approximately 1,400,000 payments annually of a value less than $275. Customer payments are received to pay electricity account charges including those related to consumption and service fees.

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8.0-VECC-62

Reference: E8/T1/S2/pg.4-12
E8/T2/S1/Tables 8-35 to 8-39

a) For 2015, Tables 8-7 and 8-14 derive fixed and variable charges for the GS>50 class of $376.90 and $2.5408/kW respectively using a base revenue requirement of $21,400,734. However, Table 8-35 indicates that these same rates yield a revenue of $22,927,498. Please reconcile.

Response:

a) The difference between the $21,100,734 (Table 8-7/Table 8-8) and $22,927,498 (Table 8-35) is the impact of the Transformer Ownership allowance and the impact of rounding the distribution rates. Specifically: $22,927,498 - $1,533,896 for the Transformer Allowance + $7,131 due to rounding results in the base revenue requirement of $21,400,734.

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9.0-VECC-63

Reference: E9/T3/S1

a) Are the $226,339 in IFRS project management costs the allocated cost of a Horizon employee? If so please explain why this cost was not expensed in prior years.

b) Please identify all Horizon internal costs recorded in account 1508.

c) Please confirm that the $544,360 balance represents the final costs for the IFRS transition and that the account will be closed subsequent to disposition

Response:

(a) The $226,339 in IFRS project management costs are not the allocated cost of a Horizon employee. They are the costs associated with an outside consultant.

(b) The internal costs recorded in account 1508 are $129,671 and are related to IT Systems Changes and Implementation as identified in Table 9-12 in Exhibit 9, Tab 3, Schedule 1.

(c) Horizon Utilities confirms that the $544,360 balance represents the final costs for the IFRS transition. The sub-account to record IFRS transition costs “1508 Other Regulatory Assets, Sub-account IFRS Transition Costs Variance” will be closed subsequent to disposition. The main account “1508 Other Regulatory Assets” will not be closed as it is used to record amounts of regulatory created assets not related to IFRS transition costs.