Responses to Association of Major Power Consumers in Ontario Technical Questions

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2-AMPCO-22

Ref: 2-AMPCO-6 (f) [Kathy]

Preamble: Horizon indicates that reactive replacement costs for XLPE primary cable at $213/metre is 323% higher than the proactive placements at $66/metre in 2013.

Please explain the differences in the two approaches to account for the substantial difference in costs between reactive and proactive replacement.

Response:

Generally reactive replacement for underground cables has the following additional cost elements as compared to proactive replacement. Each scenario is different; however most reactive replacement usually involves most or all of the following;

- Additional staff – More staff is needed to organize and execute the work and often a portion or the entire employee costs are at premium overtime labour costs. Supervisors are typically required to attend to coordinate and oversee activities and specialized staff is needed to find the cable fault(s) using high voltage current injection or high potential discharge equipment. This is in addition to the regular trouble crews that are responding to the trouble call and on-call staff if the replacement takes place after regular hours. More staff is required to troubleshoot the outage and pinpoint the damage. Additional staff must be called in to execute the cable removal replacement.
- Temporary feeds – Often when replacements take a substantial amount of time to complete, or there are critical customers affected, a temporary feed may be required. The temporary feed could consist of primary cable being placed on top of the ground in duct to bypass the faulted area or in some cases a temporary overhead pole line is built to maintain service. These feeds are labour intensive and include the cost of materials and removal once replacement is complete.
- Contractor costs – Costs include fault-finding, excavation, mobilization time, minimum call charges, emergency locates, road closures and traffic control are of which are at premium cost during reactive emergency situations. Some faults require specialized equipment which Horizon Utilities does not have and as such an outside contractor is hired. The time required to contact contractors, their travel time to the site and their time to set-up contributes to the overall length of time to replace the cable. Other workers on site may be unable to proceed with their tasks during that time.

- Restoration – Often open cut methods and/or a combination of open cut and vacuum excavation - The restoration work which results from these methods is more involved and costly when compared to the restoration work related to proactive replacement. Trenchless directional boring technology is often used in proactive replacement which results in less restoration work; this is generally not a viable option for reactive replacement.
- Loss of productivity – pulling crews from planned work during regular hours impacts production and adds additional set up and tear down time to the planned work. After hours work may require staff to be paid for rest time the following day in accordance with the Collective Agreement. Staff on paid rest time are away from work the following day which significantly impacts other planned work which staff was scheduled to complete. Often there are scheduled outages that are delayed which results in additional costs to notify customers a second time. Other delays to planned work involve loading or unloading equipment, material and tools that are specific to the reactive work.

2-AMPCO-23

Ref: 2-AMPCO-9 (j)

Preamble: Horizon provides a table in the response showing further outage data (% of customer minutes) related to equipment and material subcauses for the years 2010 to 2013.

Please discuss if Horizon has an annual % threshold or running average threshold for failures that triggers potential future capital investment.

Response:

Horizon Utilities does not have an annual % threshold or running average threshold for failures that triggers potential future capital investment. Analysis of material and equipment breakdown is one input used to identify and develop Horizon Utilities' Capital Investment Programs. The Capital Investment Programs, identified in Section 3.1.1 of Exhibit 2, Tab 6, Appendix 2-4, are designed to address: multiple asset categories having poor Health Index distributions; asset categories having a high investment requirement; and areas with operational issues that have either caused, or have a high risk of causing significant customer impact.

4-AMPCO-24

Ref: 4-AMPCO-18 (a)

Please explain why Human Resources Costs/FTE is increasing by approximately 37.5% between 2011 and 2015.

Response:

As detailed in Exhibit 4, Tab 3, Schedule 3, pages 12 – 17, Horizon Utilities re-organized the Human Resources and Healthy Workplace and Safety departments and initiated enhancements to its Human Resources strategy to meet organizational demands and better align to corporate goals and objectives.

The 37.5% cost variance between 2011 and 2015 can be categorized into the following three areas (inclusive of labour and non-labour inflationary increases):

1. Approximately 26% is attributed to the reallocation/transfer of three existing FTE to Human Resources from other programs and two new FTE as described in Exhibit 4, Tab 3, Schedule 3, pages 12-13.
2. Approximately 8.5% is attributed to enhancements and new programs to support a more robust Human Resources strategy as detailed in Exhibit 4, Tab 3, Schedule 3, pages 13-17. This includes additional costs budgeted in 2015 to support labour negotiations with respect to a new collective agreement for unionized staff.
3. The remaining 3% is related to the implementation of new technology platforms and solutions as detailed in Exhibit 4, Tab 3, Schedule 3, p. 14-15.

4-AMPCO-25

Ref: 4-AMPCO-20 (a)

Please explain the trend in Corporate Costs/customer between 2011 and 2014.

Response:

For ease of use, the table included in the response to 4-AMPCO-20(a) is shown below.

Corporate Communications Costs per Customer

Programs	2011 Actual	2012 Actual	2013 Actual	2014 Bridge Year	2015 Rate Year	2016 Rate Year	2017 Rate Year	2018 Rate Year	2019 Rate Year
Corporate Communications Costs OM&A (1)	1,098,676	945,125	1,064,847	1,127,509	1,143,176	1,171,246	1,197,486	1,222,395	1,249,236
Number of Customers (2)	237,305	238,488	240,114	241,692	243,319	245,123	247,036	249,021	250,909
Corporate Communications Costs per Customer	$ 4.63	$ 3.96	$ 4.43	$ 4.67	$ 4.70	$ 4.78	$ 4.85	$ 4.91	$ 4.98

(1) Per Table 4-29
(2) Per Table 3-28

Corporate Communication Costs per customer decreased in 2012 due to a non-recurring expenditure in 2011 relating to the Corporate Website initiative as explained in Exhibit 4, Tab 3, Schedule 3, page 19.

Corporate Communication Costs per customer increased in 2013, due to an increase in FTE of 1 between 2012 and 2013 as shown in Table 2 in the response to Interrogatory 4-AMPCO-16. The role of a Public Relations Clerk was converted to a Manager, External Communications role. This position was filled in November 2012.

Corporate Communication Costs per customer is forecasted to increase in 2014 due to an increase in public relations expenditures.

4-AMPCO-26

Ref: 2-AMPCO-21 (b)

Please explain why actual overtime costs are significantly over budget for the years 2010 (98%), 2011 (54%) and 2013 (94%) and much less so in 2012 (4.5%).

Response:

A number of weather related events not included in the overtime budgets occurred in 2010 which were responsible for the majority of the overtime variance. As a result, Horizon Utilities began tracking major storms in 2011 separate from other reactive maintenance. In 2011, a major storm was not included in overtime budgets and a number of other weather related events were responsible for the majority of the overtime variance.

Overtime budgets were increased in 2012, in part to respond to expectations of continued significant weather events which reduced the actual to budget overtime variance.

In 2013, Horizon Utilities experienced two of its most costly major storms which were not fully budgeted.

4-AMPCO-27

Ref: 2-AMPCO-21 (c)

a) Please explain quantify how the premiums for on-call and shift work are paid.

b) Please explain the drivers for the 13% increase in on-call and shift work between 2011 and 2012 actuals.

Response:

a) As provided in the response to Interrogatory 4-AMPCO-21 (c), employees designated to be “on-call” are paid a weekly premium. The shift premium is calculated based on 5% of the hourly wage rate and applies to hours worked between 7:30 p.m. and 7:30 a.m.

b) A change to Article 20.02 of the collective agreement with IBEW Local 636, “On-Call Duty and Minimum Call-Out” was implemented effective January 2012, which increased the on-call time period for underground employees from weekends, to full weeks. The remainder of the variance between 2011 and 2012 is a result of an increase in the supervisory on call premium and the impact of the inflationary increase in salaries on shift premium.

4-AMPCO-28

Ref: 2-AMPCO-21 (e)

AMPCO is unclear on how employees at the top of the pay grade receive pay increases. Please explain by way of an example.

Response:

If an employee is at the top of their pay grade they would be eligible to receive a pay increase of up to the new (adjusted) top of the pay grade.

For example:

Top of pay grade:	$50,000
Employee salary:	$50,000
Adjustment to pay grade:	2.0%
New Top of pay grade:	$51,000

Based on satisfactory performance, the employee would be eligible to receive a pay increase of up to $1,000.

4-AMPCO-29

Ref: 2-AMPCO-21 (n)

Please confirm vacant positions are not included Appendix 2-K.

Response:

Horizon Utilities confirms that vacant positions are not included in Appendix 2-K.

4-AMPCO-30

Ref: 2-AMPCO-21 (0)

Please explain the 34% increase in contractor costs for 2013 actual compared to 2012 actual.

Response:

The 34% increase in contractor costs for 2013 actual compared to 2012 actual supports the reduction of vacancies from 2012 to 2013 as provided in the response to 4-AMPCO-21 (l).

Horizon Utilities utilizes contract resources to temporarily fill vacant positions pending a permanent hire.

Responses to Consumers Council of Canada Technical Questions

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1-CCC-41TC

Reference 1-Staff-2

The Council is interested in better understanding the scope of the list of "reopeners" that Horizon has proposed as "significant events outside the normal course of business". Please give examples additional items that Horizon views as meeting the OEB's Z-factor criteria that are not included on this list.

Response:

Horizon Utilities has listed the reopeners that have been contemplated in its response to Interrogatory 1-Staff-2. Horizon Utilities does not have additional examples to add at this time.

1-CCC-42TC

Reference 1-Staff-6

Please provide a detailed explanation as to how, from a practical perspective, Horizon intends to apply the materiality threshold.

Response:

Events that have a cost impact over the term of the Application greater than the materiality threshold ($564,780) calculated in Exhibit 1, Tab 6, Schedule 1, individually or cumulatively, would be included in the annual update. For example, if there was one incident that exceeded materiality or if there was a number of smaller incidents that accumulate to the materiality threshold, these would be included in the annual update process for reopeners.

Additionally, an event in a particular year resulting in a cost impact above materiality across the remaining years of the rate plan would be included in the annual update.

1-CCC-43TC

Reference 1-CCC-1 – Attachment 8

Horizon makes reference to the Board's revenue decoupling consultation process and its decision to proceed with a 100% fixed charge for low-volume consumers. What is Horizon's current position on the 100% fixed charge? If it is optional, would Horizon pursue the implementation of 100% fixed charge?

Response:

Horizon Utilities' position is that its cost structure is largely fixed relative to the number of customers. Consequently, a fixed charge makes sense for the sector. It is premature for Horizon Utilities to offer a position on the 100% fixed charge until the full implications of such have been articulated by the Board. Horizon Utilities would consider the implementation of a 100% fixed charge during the 2015-2019 rate plan term depending upon the full implications of such and the direction from the OEB.

1-CCC-44TC

Reference 1-CCC-2

There are a number of e-mails to employees provided in the response regarding the development of the Application – one refers to the Distribution System Plan Review Workbook. Please explain how Horizon has taken the information gathered through that process and used it in the development of its Distribution System Plan.

Response:

For clarification, the process that is referred to in this question is interpreted to mean how the customer outreach process was considered in the development of the DSP. The Board issued the Chapter 5 – Consolidated Distribution System Plan Filing Requirements (EB-2010-0377) in March of 2013. In August 2013, Horizon Utilities commenced development of the DSP Review Workbook which was completed in January 2014. Customers were engaged and customer feedback was reviewed and compared to the Horizon Utilities' DSP. As discussed in Horizon Utilities response to Interrogatory 2-Staff-17, customer preferences expressed through the customer engagement process validated the approach adopted in Horizon Utilities' DSP, with its emphasis on system renewal over the 2015-2019 rate plan period. Horizon Utilities did not alter its capital investment levels based on the outcomes from the Innovative Customer Consultation Report.

1-CCC-45TC

Reference 1-CCC-10, 1-CCC-11

The answer describes ways in which Horizon has taken measures to manage and mitigate internal risks associated with capital and operating expenditures. Regardless, forecast risk remains and as the plan proceeds those forecasts are ultimately going to be wrong. In the next answer Horizon concludes that an ESM would require a wholesale change for the distribution sector in terms of the current rate setting options. Is it Horizon's view that a custom plan cannot incorporate some form of an ESM? If so, how has Horizon arrived at that conclusion?

Response:

Yes, Horizon Utilities agrees that a Custom IR can include an ESM. However, Horizon Utilities is not proposing such.

5-CCC-46TC

Reference 5-CCC-36

Please provide the actual weather-normalized ROE figures for 2011, 2012 and 2013 if those differ from the numbers provided.

Response:

Horizon Utilities does not currently measure or report weather normalized ROE. However, in an attempt to provide a meaningful answer to this question, Horizon Utilities has calculated ROE for each of the years using budgeted volumetric billing determinants, which were prepared on a weather normalized basis. This provides a proxy for weather normalized ROE of 8.23%, 10.55%, and 8.84% for 2011, 2012, and 2013 respectively.

Responses to City of Hamilton Technical Questions

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1 – C of H 11 TC

(a) The response to this interrogatory creates the impression that Horizon has, in allocating costs, just followed the OEB-approved cost allocation methodology. Has Horizon deviated from that cost allocation model? If so, in what ways and with what effect on the rate classes?

(b) How were the common costs, in the amount of $399,055, allocated to the LU(2) class derived?

(c) What percentage is $399,055 of the total common costs of Horizon?

Response:

a) Horizon Utilities has followed OEB-approved cost allocation methodologies in the preparation of this Application. Horizon Utilities has not deviated from OEB-approved Cost Allocation model.

b) The common costs of $399,055 were allocated to the LU (2) class within the OEB Cost Allocation model. This amount can be computed by taking the total costs allocated to the LU (2) class of $432,222 (cell I40 of Tab O1) and subtracting the directly allocated costs of $33,167 (cell I35 of Tab O1).

c) The common costs of $399,055 represents 0.35% of the total common costs.

C of H 12TC

Cost Allocation and Rate Design EMP Presentation, May 1, 2013

(a) What was the impetus for the creation of this Presentation?

(b) What is the "Project" referred to on page 2 of the Presentation?

(c) What are the "customer requests to review Cost Allocation" referred to on page 3 of the Presentation?

(d) What are the "strategic issues within Horizon Utilities' service area" referred to on page 3 of the Presentation?

(e) What is meant by the statement "mitigate the shareholder's risk" which appears on page 3 of the Presentation?

(f) The graph on page 6 of the Presentation shows "Large Use Customer – Demand", from January of 2012 to December of 2012. Why was the data presented on the graph limited to that timeframe?

(g) In the Risk Matrix, which appears on page 18 of the Presentation, there are references to "SU direct connect to HONI" and to the "probability of bypass". On what basis did Horizon calculate the risk of "direct connect to HONI" and the risk of "bypass"?

Response:

a) The impetus for the creation of this presentation was to present an update on the Cost Allocation and Rate Design project to the Executive Management ("EMT") members and to request a decision on the next steps including creating a new Large Use customer class. The objectives of reviewing Cost Allocation and Rate Design are specified on slide 3 of the presentation.

b) The project referred to on page 2 of the Presentation is the Cost Allocation and Rate Design ("CARD") project.

c) Horizon Utilities' industrial customers had provided their view to Horizon Utilities in a meeting on October 3, 2012; they indicated that they believed that they were served by limited, dedicated distribution assets. Horizon Utilities advised these customers that it would be reviewing cost allocation and rate design as a component of its Application and that part of such review would include reviewing cost causality to ensure that there was equity in cost allocation. Horizon Utilities committed to consider the views of its industrial customers as part of its review.

d) The strategic issues considered by Horizon Utilities may be summarized under two categories: i) customer growth and retention; ii) rate competitiveness.

The fundamental customer growth issue is articulated in Exhibit 1, Tab 2, Schedule 4, page 1 lines 26-29 and page 2 lines 1-14 with corresponding customer cost implications. The low customer growth profile of Horizon Utilities' service area results in rate pressure arising from inflationary and renewal based expenditure. The same pool of customers effectively shares rising costs.

Rate competitiveness is also a consideration in addressing customer growth. As Horizon Utilities reviews its cost allocation and rate design, it is mindful of inequities between classes that may be causing rate competitiveness issues that are limiting to customer growth.

These strategic issues align with ratepayer concerns. Fostering customer growth and minimizing loss of load within the construct of OEB ratemaking policy serves to mitigate the impact of rate increases for all customers.

e) Shareholder risks, in part, are aligned to the issues described in d). Low customer growth is a shareholder risk to the extent that it cannot increase the value of its investment through additional investments in utility infrastructure. Rate competitiveness is important to the shareholder to support its merger and acquisition strategy through being an attractive merger partner. Customer growth supports both of these strategic issues. In the absence of such, these strategies are at risk.

The prospect of revenue volatility with respect to both customer loss and the variable portion of distribution rates create shareholder risk. Cost allocation and rate design afford opportunities for Horizon Utilities to mitigate these risks through proposals for equitable changes that conform to OEB ratemaking policy.

f) The 2012 demand data represented the last full year of such data that was available at the time for assessment purposes.

g) These risks were not quantified. Their identification on page 18 was considered on a qualitative basis only.

C of H 13TC

Recommendation on Cost Allocation – August 2013

(a) Based on what considerations did Horizon move from the EMP Presentation, dated May 1, 2013 (C of H 2, attachment 2) to the Recommendation on Cost Allocation dated August 2013?

Response:

Horizon Utilities' recommendations were based on considerations of cost causality and equity between rate classes within the confines of OEB ratemaking policy.

2 (Attachment 3) - C of H 14TC

CoS Scenario Bill Impacts November 26 2013

(a) For whom was this presentation prepared?

(b) What decisions, if any, was Horizon seeking from this presentation?

(c) Why were the graphs entitled "Rate Curve Competitiveness for 2015" prepared? With whom does Horizon compete and for what?

(d) The graph entitled "Scenario 1: Existing Rate Classes", which appears on page 6 of this presentation lists 8 utilities other than Horizon. Why were those 8 utilities selected?

Response:

a) This presentation was prepared for Horizon Utilities' Executive Management Team.

b) This presentation was used to illustrate the outcomes of creating the LU(1) and LU(2) classes on cost allocation, revenue to cost ratios, and rates. The purpose of the presentation was information.

c) Please refer to Horizon Utilities' response to COH-12-TC d) and e).

d) The utilities in this graph were chosen for comparison based on geographic location relative to Horizon Utilities and based on the existence of a Large Use customer class.

2 (Attachment 6) - C of H 15TC

Bill Impacts – EMT Review Target Area Comparison

(a) For whom was this document prepared?

(b) Why was it prepared? What is the relevance for Horizon's rate application of the comparisons?

(c) The graphs in this document compare Horizon to other utilities. Please indicate the criteria upon which the other utilities were selected.

Response:

a) This document was prepared for Horizon Utilities' Executive Management Team.

b) This presentation was used to benchmark Horizon Utilities' proposed 2015 distribution rates (as at the time of the drafting of the presentation) against other Ontario LDCs for informational purposes.

c) The comparative utilities were selected based on geographical proximity and size relative to Horizon Utilities.

2 (Attachment 5) - C of H 16TC

CoS Scenario Bill Impacts November 6, 2013

Introduction:

This document contains a comparison of two scenarios. Scenario 1 "(No LU (2) Class)" shows the bill impact in 2015 for the streetlight class to be an increase of 8.35% over 2014. In Scenario 2 "(Introduction of LU (2) Class in 2015)", the impact on the streetlight class is an increase of 16.76% in 2015 over 2014. In the application as filed, the proposed distribution bill impact for the streetlight class is 24.5% for 2015 over 2014.

(a) Was the presentation "CoS Scenario Bill Impacts" dated November 6, 2013, the final presentation to the EMT before the application was filed?

(b) Did the EMT consider the distribution bill impact on the streetlight class of 24.5% prior to the application being filed? If so, when, and under what circumstances?

(c) Was the City of Hamilton told what the distribution bill impact increase would be prior to the filing of the application? If not, why not? Was the City of Hamilton consulted about any of the scenarios referred to in this attachment?

Response:

a) Yes this was the final presentation prepared prior to the filing of the Application.

b) The EMT reviewed the bill impact of all rate classes, including the Street Light class, prior to filing the Application. As stated in Exhibit 8, Tab 4, Schedule 1, Page 1, Horizon Utilities considered the 10% total bill threshold as the guideline in regard to rate mitigation.

c) Customers were not provided with the bill impacts of the Application prior to the Application filing. However, the Distribution System Plan Workbook included indicative bill impacts. The City of Hamilton was informed of the bill impacts as follows: Mayor and City Councillors on May 16, 2014; City of Hamilton staff regarding Large Use accounts on May 22, 2014; and specific to Street Lights on May 26, 2014.

2 (Attachment A) - C of H 17TC

Meeting with Large Use Customers – November, 2013 (Supplementary Response to C of H Interrogatory 2(a)

(a) What was the impetus for this meeting and for the proposal outlined in the slide deck?

(b) Did the large use customers ask for a reduction in their rates?

(c) If so, when and under what circumstances?

(d) What was the "evolving Financial Plan" referred to on page 4 of the slide deck?

(e) On page 6 of the slide deck, there is a statement that "This is a new and untested cost allocation method to present to the Ontario Energy Board." What was "new and untested"?

Response:

a) Horizon Utilities met with the Large Use customers in November 2013 as a follow up to a discussion in 2012 where the Large Use customers identified that they were concerned about the extent of the distribution assets that serve them relative to other customers; they were aware that their facilities were largely served by dedicated assets.

b) No, the Large Use customers did not ask for a reduction in their rates.

c) Not applicable.

d) The "evolving Financial Plan" was the Financial Plan that was in development at the time of this presentation and meeting with the Large Use customers. The Financial Plan was filed in Horizon Utilities' response to Interrogatory 1-CCC-1.

e) Horizon Utilities has not previously applied for a directly allocated rate class. The statement refers to the fact that this method is new to Horizon Utilities. Horizon Utilities has not conducted an exhaustive search for other distributors with directly allocated costs; however, it is presumed that the tab included in the model for directly allocated costs was included because some LDCs have costs that are directly allocated. Customers and/or customer classes with dedicated facilities that would appropriately be directly allocated would have predated the 2006 cost allocation information filings.

3 - C of H 18TC

Introduction:

The answer to this interrogatory indicates that Horizon uses the terms “devices” and

“connections” interchangeably and that each device is a connection. However, the answer also says that there is a distinction drawn between devices (individual lights) and connections.

(a) Does Horizon charge Hamilton on the basis of the number of devices as opposed to the number of connections? If so, what is its justification for doing so?

(b) What is the rate-making impact of charging Hamilton on the basis of the number of devices as opposed to the number of connections?

Response:

a) All street lighting customers within Horizon Utilities’ service area are charged a per device distribution rate. Horizon Utilities charges this rate as approved by the Ontario Energy Board in the Cost of Service and IRM rate applications. Costs are allocated to the street lighting class on the basis of connections. Using the fully allocated costs, a rate per device is calculated. The rate on Horizon Utilities’ Tariff of Rates and Charges is the computed and OEB-approved per device charge which is then charged per device to the Street Lighting customers.

b) If Horizon Utilities were to charge its Street Lighting customers on the basis of the number of connections rather than the number of devices, the distribution rate would be higher, but the volume that rate was charged on would be lower. The rate-making impact on charging per device versus connection is neutral.

EXAMPLE:

Charge per Device (Current Method):

Total Distribution Revenues	X	**Fixed Revenue % (Revenue from Devices)**	=	**Fixed Distribution Revenue (Revenue from Devices)**
$2,740,679		68.23%		$1,869,880
Total Distribution Revenues	X	**Variable Revenue % (Revenue from kW)**	=	**Variable Distribution Revenue (Revenue from kW)**
$2,740,679		31.77%		$870,799

Fixed Distribution Revenue (Revenue from Devices)	÷	**Annual Forecast Devices**	=	**Fixed Distribution Charge per Device**
$1,869,880		628,608		$2.97
Variable Distribution Revenue (Revenue from kW)	÷	**Annual Forecast kW**	=	**Total Variable Distribution Revenue**
$870,799		110,006		$7.9159

Charge per Connection (Alternate Method):

Total Distribution Revenues	X	**Fixed Revenue % (Revenue from Connections)**	=	**Fixed Distribution Revenue (Revenue from Connections)**
$2,740,679		68.23%		$1,869,880
Total Distribution Revenues	X	**Variable Revenue % (Revenue from kW)**	=	**Variable Distribution Revenue (Revenue from kW)**
$2,740,679		31.77%		$870,799

Fixed Distribution Revenue (Revenue from Connections)	÷	**Annual Forecast Connections**	=	**Fixed Distribution Charge per Connection**
$1,869,880		478,356		$3.91
Variable Distribution Revenue (Revenue from kW)	÷	**Annual Forecast kW**	=	**Total Variable Distribution Revenue (Revenue from kW)**
$870,799		110,006		$7.9159

7 (Attachment 1)- C of H 19TC

City of Hamilton Streetlight Audit Report

(a) Have the results of this audit been accepted by the City of Hamilton as the basis for the rates charged to the streetlight class?

Response:

a) The results of the audit were presented to the City of Hamilton on November 13, 2013. For a small portion, the daisy-chain ratio was unknown. For these streetlights for the purpose of the Application and the Cost Allocation model, Horizon Utilities assumed a 3:1 daisy chain ratio. As Horizon Utilities had communicated to the City of Hamilton in its meeting on May 27, 2013, the results of the study would be used for the Application as such would represent the best information available.

Responses to Energy Probe Technical Questions

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1-Energy Probe-58TC

Ref: 1-Energy Probe-3

a) Please confirm that Attachment 2 shows that the cumulative revenue requirement over 2015 through 2019 based on the Horizon proposal is about $24.6 million higher than under a price cap approach using the inflation and productivity assumptions used.

b) Please confirm that Attachment 1 shows that the cumulative OM&A over 2015 through 2019 based on the Horizon proposal is about $23.1 million higher than under the price cap approach using the assumptions used.

c) Please confirm that Attachment 4 shows that the cumulative OM&A difference noted above in part (b) would be $29.0 million when the base productivity of -0.72% for 2012 and 2013 is included.

Response:

a) Horizon Utilities does not confirm the amount of $24.6MM. Horizon Utilities confirms that its aggregate proposal for Revenue Requirement across 2015-2019 is approximately $23.1MM higher than under a price cap approach using the inflation and productivity assumptions in 1-EP-3 Attachment 2. This is evident by summing the values in the last line of this attachment corresponding to the 2015-2019 IR years.

b) Horizon Utilities does not confirm the amount of $23.1MM. Horizon Utilities confirms that the aggregate OM&A for 2015-2019 underlying its proposal for aggregate Revenue Requirement for those years is approximately $24.6MM higher than under a price cap approach using the inflation and productivity assumptions in 1-EP-3 Attachment 1. This is evident by summing the values in the last line of this attachment corresponding to the 2015-2019 IR years.

c) Confirmed.

1-Energy Probe-59TC

Ref: 1-Energy Probe-5

a) With respect to the annual adjustment applicable to long term debt, is Horizon requesting that the Board approve the timing and amount of forecasted long term debt issued in 2015 through 2019 now, or will this be part of the annual filing each year?

b) Please explain why an adjustment related to CDM results is required if there is an LRAM variance account in place.

c) Would any variance in the CDM results from that forecast in each of 2015 through 2019 also result in an adjustment to the working capital related to the cost of power?

d) Would the tax rate change adjustment also include changes to CCA rates, and tax credits?

Response:

a) Exhibit 5, Tab 1, Schedule 1, page 1 lines 22 through 26 and page 2 lines 1 through 15 articulate Horizon Utilities' request with respect to an annual adjustment for long-term debt and related rationale. Within this reference, Horizon Utilities specific request with respect to long-term debt is as follows: *"Horizon Utilities requests that: …. ii.) the Long-Term Debt rate used for all long-term deemed debt, funded and unfunded, be the weighted average of rate applicable to funded debt for Horizon Utilities; …"*

Horizon Utilities is not requesting approval for the timing or amount of the debt issuance. Horizon Utilities is requesting that the debt rate be updated as indicated above, as and when it issues new long-term debt.

Exhibit 5, Tab 1, Schedule 3, page 3 lines 3-14 provides Horizon Utilities' estimated timing and amount of issuance based on the best available information available to it in forecasting its incremental long-term debt requirements for the 2015 to 2019 years. Within this reference, Horizon Utilities also indicates that: *"The actual timing, amount, and term of new debt issuance will be influenced by several factors such as actual versus anticipated cash flow and financial market conditions."*

In summary, Horizon Utilities will include in its annual filings the details of any new debt issuances, if any. The nature of its request for adjustment will be limited to a revision of the long-term debt rate used for long-term deemed debt in the manner described above.

b) An annual adjustment to CDM results is not required if the Board continues the use of the LRAMVA into the years 2015-2019 to capture the revenue impact from the difference between actual and forecasted CDM results.

c) There would be no adjustment to the working capital related to the cost of power resulting from the CDM adjustment.

d) Horizon Utilities submits that the tax rate change adjustment should incorporate changes in tax legislation. This would include, for example, changes to: i) combined income tax rates; ii) rates used to compute tax credits; iii) CCA rates; etc. The tax rate change adjustment is not intended to true up underlying values applied to these rates, such as: i) actual income for tax purposes; ii) actual capital additions; iii) number of apprentices eligible for tax credits; etc.,.

1-Energy Probe-60TC

Ref: 1-CCC-4

Please explain, with references to the evidence, how the Horizon custom IR filing addresses each of the three bullet points noted in the statement.

Response:

Horizon Utilities has addressed issues on forecasts (revenues, costs, inflation and productivity) throughout the Application, particularly in Exhibits 1, 2 and 4, and in its response to Interrogatory 1-SEC-8. Horizon Utilities has also addressed the Board's inflation and productivity analyses in its responses to Interrogatories 1-EP-3, 1-BOMA-7 and 1-CCC-5. With respect to the Interrogatory 1-CCC-4 reference under which this Technical Conference Question is being asked, Horizon Utilities makes it a practice of contacting a party if clarification is needed on the questions asked. Ms. Girvan of Consumers Council of Canada ("CCC") was contacted for clarification on CCC-4 and CCC-5. She had identified that CCC's question was contained in 1-CCC-5, to which Horizon Utilities has responded.

In any event, the Board will consider the evidence put forward by Horizon Utilities and assess the evidence against its own assessment and its own criteria as to how this Application meets the letter or spirit of the RRFE in this early stage of implementation of the RRFE.

1-Energy Probe-61TC

Ref: 1-CCC-10

a) Is Horizon proposing a capital expenditures variance account to provide a level of protection against unacceptable risk?

b) Has Horizon considered any other type of mechanism that would protect ratepayers from forecast risk while at the same time providing an incentive to Horizon to meet its forecasts?

Response:

a) Horizon Utilities has not proposed a capital expenditures variance account in its Application as provided in the response to Interrogatory 1-Staff-3 parts b) and c).

b) No, Horizon Utilities has not considered any other type of mechanisms.

1-Energy Probe-62TC

Ref: 1-CCC-11

Given the recent Decision for Enbridge Gas Distribution in EB-2012-0459, has Horizon changed its position on an earnings sharing mechanism?

Response

Horizon Utilities is not proposing any amendments to its filed Application or interrogatory evidence as a result of the recent Board decision for Enbridge Gas Distribution in EB-2012-0459.

1-Energy Probe-63TC

Ref: 1-VECC-1

Please provide Horizons expectations with regard to the material that would be filed in each of the annual adjustment applications with the Board and intervenors.

Response:

Horizon Utilities expects to provide its Application to the Board to support the annual adjustments as determined in this proceeding. Horizon Utilities does not file information directly with intervenors.

1-Energy Probe-64TC

Ref: 1-STAFF-1

a) Please explain how the administrative process proposed for setting rates for 2016 through 2019 would allow the Board and intervenors the opportunity to review and provide alternatives for the need for and cost of long term debt and any additional annual adjustments as identified by the Board, among other things.

b) Does Horizon agree that any reopeners would require a rate filing and a review of the evidence and proposals by the Board and intervenors? If not, why not?

Response:

a) Horizon Utilities submits that the administrative process is not within its discretion. Horizon Utilities would not presume to offer a process for the Board to review and approve setting rates for 2016 to 2019 with respect to the annual adjustments identified in the application or as otherwise identified by the Board.

Please also refer to 1-EP-59TC a) with respect to the scope of Horizon Utilities' request for annual adjustments with respect to the long-term debt rate.

b) Horizon Utilities submits that the process with respect to reviewing and approving reopeners is not within its discretion. Horizon Utilities would not presume to offer a process for the Board to review and approve setting rates for 2016 to 2019 with respect to reopeners.

1-Energy Probe-65TC

Ref: 1-STAFF-8

The response indicates that the non-labour inflation index of 1.50% is 0.5% below the most recent GDPIPIFDD estimate provided in Appendix B of the report referenced and the Bank of Canada target for inflation.

a) Please confirm that the most recent GDPIPIFDD figure used by the Board to set the 2014 price escalator is 1.8% as shown in Appendix C to the EB-2010-0379 Report of the Board dated November 21, 2013.

b) Please confirm that the Bank of Canada inflation target is based on the consumer price index and not the GDPIPIFDD.

c) Please provide the actual increase in the GDPIPIFDD for each of 2012 and 2013, as well as the year over year increase for the first quarter of 2014.

Response

a) Horizon Utilities confirms that the most recent GDPIPIFDD used by the Board is 2.0%. Please refer to the GDPIPIFDD statistic corresponding to 2014 (est.) in Appendix B of the *Report of the Board: Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* as corrected on December 4, 2013 (the "Rate Setting Report"). This is the reference rate for Horizon Utilities' response to Interrogatory 1-Staff-8, page 1, lines 14-15 and page 2, lines 1-3.

Appendix C of the Rate Setting Report identifies the Annual Index applicable to 2014 rates as 1.7%. Within such rate, Horizon Utilities confirms that the GDPIPIFDD component is 1.8%.

b) Horizon Utilities confirms that the Bank of Canada inflation target is based on the consumer price index.

c) The actual annual increase in GDPIPIFDD for 2012 is provided in Appendix C of the Rate Setting Report as 1.8%.

The actual increase annual in GDPIPIFDD for 2013 has been derived from Statistics Canada Table 380-0066 (dated 2014-05-29) under Implicit Price Indexes corresponding to Final Domestic Demand. This value has been computed as 1.6%.

The year over year increase in GDPIPIFDD for the first quarter of 2014 has been derived from Statistics Canada Table 380-0066 (dated 2014-05-29) under Implicit Price Indexes corresponding to Final Domestic Demand. This value has been computed as 2.0%.

2-Energy Probe-66TC

Ref: 2-Energy Probe-10

Please explain why it takes 3 days to mail a bill from the billing date.

Response:

The 3 days that Horizon Utilities has provided as the Mailing Lag includes 1 day for internal processes including printing and preparing the invoice for mailing, and 2 days for Canada Post to deliver the invoice to the customer's mailing address.

2-Energy Probe-67TC

Ref: 2-Energy Probe-11

What assumptions did Horizon make with respect to postage and envelope costs with respect to the potential to shift more customers from receiving a hard copy of their bill to being sent it by e-mail or logging on to the Horizon website and downloading a copy?

Response:

With reference to 2-Energy Probe-11, Horizon Utilities did not include any specific reductions in postage, paper, and envelope expenditures with respect to potential increases in customer e-billing.

As provided in Horizon Utilities' response to Interrogatory 1-BOMA-8 which provides details of the productivity savings anticipated from increased e-billing volumes, modest incremental savings of approximately $20,000 are forecasted annually from 2016 through to 2019. This is not material as compared to the postage expenditure of approximately $1.7MM, and primarily acts as cost containment measure against future Canada Post postage increases.

2-Energy Prober-68TC

Ref: 2-Energy Probe-13

a) Would one component of the annual working capital adjustment proposed by Horizon include any change to the average lead time for interest expenses based on new debt instruments added in 2015 through 2019?

b) The response associated with the average payment lead times for computer maintenance indicates that it is based on a 3 year contract that was paid at the beginning of the term of the agreement that ends March 31, 2015. How has Horizon forecast the computer maintenance costs going forward in terms of a new agreement with payment terms?

Response:

a) As indicated in Exhibit 1, Tab 2, Schedule 2 page 12 of the Financial Performance section, one component of the annual working capital adjustment would include any change to the average lead time for interest expenses based on new debt instruments added in 2015 through 2019, as a result of either a change in the interest or a change in payment dates if they differ from the current dates used in the Lead Lag Study produced by Navigant Consulting Inc.

b) Horizon Utilities forecast the computer maintenance costs based on a new 3 year contract, with similar payment terms.

2-Energy Probe-69TC

Ref: 2-Energy Probe-15

If Horizon recovered the NBV of $7,974,590 at the end of 2014 through a rate rider, please calculate the monthly rate rider by rate class if the amount was recovered over a 12 month period or over a 24 month period.

Response:

Horizon Utilities provides a monthly rate rider by rate class if the NBV of $7,974,590 is recovered through a rate rider over a 12 month period and a 24 month period in Tables 1 and 2 respectively below. The rate riders in Tables 1 and 2 below do not include a rate of return.

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. As such, Horizon Utilities reiterates that if recovery of stranded meters is through a rate rider, it expects the recovery to include a regulated rate of return. Otherwise, Horizon Utilities submits that the recovery of only the NBV of the stranded meters is punitive in that it does not provide Horizon Utilities with a fair return on the capital it has invested in conventional meters.

Table 1 – 12 month rate rider to recover NBV of $7,974,590

Customer Class	# of Active Metered Customers (average 2015)	NBV of Stranded Meters	Monthly Charge
Residential	220,565	$6,141,165	$2.32
GS< 50kW	18,428	$1,561,125	$7.06
GS>50kW	2,198	$272,299	$10.32
Total	**241,190**	**$7,974,590**	

Table 2 – 24 month rate rider to recover NBV of $7,974,590

Customer Class	# of Active Metered Customers (average 2015)	NBV of Stranded Meters	Monthly Charge
Residential	220,565	$6,141,165	$1.16
GS< 50kW	18,428	$1,561,125	$3.53
GS>50kW	2,198	$272,299	$5.16
Total	**241,190**	**$7,974,590**	

2-Energy Probe-70TC

Ref: 2-SIA-10

The response indicates that Horizon is prepared to recover the NBV of the stranded meters through a rate rider over an extended period of time (five years or eight years) provided that the recovery includes a regulatory rate of return.

Please provide a list of other distributors (including file numbers) where the Board has approved recovery the NBV of the stranded meters including a regulatory rate of return.

Response

The applications of distributors for recovery of stranded meters are a matter of public record. As such, Horizon Utilities has not reviewed all related applications.

However, Horizon Utilities is aware that in the case of Hydro One Networks Inc. ("Hydro One"), the Board had approved recovery the NBV of the stranded meters including a regulatory rate of return in Hydro One's Cost of Service Application (EB-2005-0378) as identified in Hydro One's response to Board Staff Interrogatory 81 in Hydro One's Cost of Service Application (EB-2013-0416).

Board Staff Interrogatory 81 and Hydro One's response are provided below for ease of reference.

<u>Board Staff Interrogatory 81</u>

The Board's Distribution Filing Requirements state that, if not already addressed in a previous Board decision, distributors must file as part of their 2014 application a proposed treatment for the recovery of stranded meters that is in conformity with the approach taken by the Board.

Please provide a proposed treatment for the recovery of stranded meter costs in conformity with the approach taken by the Board, as described in section 2.5.1.4 of the Distribution Filing Requirements.

<u>Board Staff Interrogatory #81 Hydro One Response</u>

Hydro One does not have any stranded meters. This is consistent with the recommendation in the Foster Associates 2005 Distribution Depreciation Study which was used to determine Hydro One's 2006 Distribution rates approved by the Board in RP-2005-0020/EB-2005-0378, amortization of conventional meters in account 1860 was changed to 5 years to be consistent with the timeline for the Province's initiative to replace conventional meters with smart meters.

2-Energy Probe-71TC

Ref: 2-SEC-20 &
1-Staff-15

a) Please provide a table for 2015 through 2019 that shows the O&M reductions from distribution system capital investments in the same level of detail as provided in part (c) of the response. Please also provide a total line in the table.

b) Please incorporate a second part to the table requested in part (a) above that reflects the incremental cost savings after 2013 as shown in Table 1 to the response to 1-Staff-15 (at the level of construction & maintenance, customer service, supply chain management, etc.), as well as any other reductions in OM&A not included in responses to 2-SEC-20 and 1-STAFF-15.

c) Please confirm that incremental savings between 2013 and 2014 as shown in the response to 1-Staff-15 is about $1.46 million.

Response:

a) Horizon Utilities provides a summary of O&M reductions from distribution system capital investments in Table 1 below. The savings are all considered operating cost savings and not productivity improvements.

Table 1 – O&M Reductions from Distribution System Capital Investments

Initiative	2016	2017	2018	2019	Total
Station Decommissioning	$23,000	$82,000	$52,000	$178,000	$335,000
Corrective Maintenance	$55,000	$55,000	$55,000	$55,000	$220,000
Total OM&A Reduction	**$78,000**	**$137,000**	**$107,000**	**$233,000**	**$555,000**

b) Horizon Utilities provides a summary in Table 2 below of incremental cost savings as requested above.

Table 2 – Incremental Cost Savings from Distribution Capital Investments

Department	2016	2017	2018	2019	Total
Construction & Maintenance	**$78,000**	**$137,000**	**$107,000**	**$233,000**	**$555,000**

c) Horizon Utilities confirms that the incremental savings between 2013 and 2014 as shown in the response to Interrogatory 1-Staff-15 is $1.46 million.

3-Energy Probe-72TC

Ref: 3-Energy Probe 18c

What is the impact on the load forecast (by rate class) and on the revenue requirement for each of 2015 through 2019 if the most recent Conference Board forecasts are used?

Response:

The most recent Conference Board forecasts have been provided as attachment 3-EP-18c_Attch 1_Conference Board of Canada Economic Variables in Horizon Utilities Interrogatory Response to 3-EP-18c. The impact to the load forecast (by rate class) updating for the most recent Conference Board forecasts is provided in Tables 1-4 as identified below. The impact on the revenue requirement for each of 2015 through 2019 is provided in Table 5 below. The cumulative impact on revenue requirement for the rate plan term of using the most recent Conference Board forecasts is $1,929.

- Table 1: Forecasted Volumes and Customers 2014-2019 Using Most Recent Conference Board Forecast
- Table 2: Forecasted Volumes and Customers 2014 – 2019 (As Filed in Exhibit 3, Tab 2, Schedule 1, Page 2)
- Table 3: Absolute Variance between the Forecasted Volumes and Customers 2014 - 2019 Using Most Recent Conference Board Forecasts vs. Forecasted Volumes and Customers 2014 – 2019 as filed in Exhibit 3, Tab 2, Schedule 1, Page 2
- Table 4: Percentage Variance between the Forecasted Volumes and Customers 2014 - 2019 Using Most Recent Conference Board Forecasts vs. Forecasted Volumes and Customers 2014 – 2019 as filed in Exhibit 3, Tab 2, Schedule 1, Page 2

Table 1: Forecasted Volumes and Customers 2014-2019 Using Most Recent Conference Board Forecast

Customer Class	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Residential						
Customers	218,980	220,349	221,822	223,397	225,043	226,598
kWh	1,634,449,350	1,621,224,457	1,619,130,704	1,612,961,145	1,608,380,921	1,603,801,426
GS < 50 kW						
Customers	18,383	18,417	18,472	18,533	18,597	18,657
kWh	588,132,628	584,777,386	584,352,522	581,705,356	580,068,542	578,331,821
GS > 50 kW						
Customers	2,145	2,179	2,210	2,241	2,273	2,304
kWh	1,858,793,791	1,853,712,212	1,848,952,591	1,837,366,359	1,828,605,655	1,819,670,525
kW	5,116,919	5,102,729	5,075,041	5,057,603	5,033,414	5,008,766
Large Use (1)						
Customers	7	7	7	7	7	7
kWh	264,367,942	269,695,476	275,173,538	280,948,387	286,416,820	291,865,629
kW	613,675	626,042	638,758	652,163	664,857	677,505
Large Use (2)						
Customers	4	4	4	4	4	4
kWh	322,581,816	329,082,474	335,766,806	342,813,278	349,485,861	356,134,499
kW	1,846,057	1,883,259	1,921,512	1,961,837	2,000,023	2,038,071
USL						
Customers	1,857	1,857	1,857	1,857	1,857	1,857
Connections	3,047	3,039	3,031	3,023	3,014	3,006
kWh	11,620,990	11,397,660	11,174,331	10,951,001	10,727,671	10,504,342
Sentinel						
Customers	248	248	248	248	248	248
Connections	407	401	395	389	383	378
kWh	455,814	437,397	418,980	400,564	382,147	363,731
kW	1,294	1,241	1,185	1,135	1,083	1,030
Street Lighting						
Customers	4	4	4	4	4	4
Devices	52,412	52,384	52,356	52,328	52,300	52,273
kWh	39,744,804	39,694,810	39,602,538	39,651,553	39,629,670	39,610,413
kW	110,065	110,006	109,948	109,890	109,831	109,773
Standby						
kW	281,814	290,976	300,137	309,299	318,460	327,622
Total						
Customers	241,628	243,065	244,624	246,292	248,032	249,678
Customers/Connections/Devices	295,385	296,780	298,297	299,923	301,622	303,226
kWh	4,720,147,134	4,710,021,872	4,714,572,011	4,706,797,643	4,703,697,286	4,700,282,385
kW from applicable classes	7,969,824	8,014,254	8,046,582	8,091,927	8,127,668	8,162,767

Table 2: Forecasted Volumes and Customers 2014 – 2019 (As Filed in Exhibit 3, Tab 2, Schedule 1, Page 2)

Customer Class	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Residential						
Customers	219,031	220,574	222,279	224,093	225,976	227,764
kWh	1,630,039,291	1,617,715,605	1,615,569,770	1,608,117,860	1,604,991,612	1,600,739,130
GS < 50 kW						
Customers	18,386	18,429	18,494	18,565	18,639	18,709
kWh	589,101,097	586,002,830	585,648,636	583,142,939	581,558,617	579,899,038
GS > 50 kW						
Customers	2,154	2,196	2,230	2,258	2,286	2,316
kWh	1,862,301,069	1,857,864,416	1,852,830,462	1,841,172,846	1,831,925,238	1,822,597,172
kW	5,126,645	5,114,245	5,085,745	5,068,149	5,042,608	5,016,885
Large Use (1)						
Customers	7	7	7	7	7	7
kWh	264,367,942	269,877,849	275,125,662	280,664,097	285,758,686	290,887,091
kW	613,675	626,465	638,647	651,503	663,329	675,234
Large Use (2)						
Customers	4	4	4	4	4	4
kWh	322,581,816	329,305,006	335,708,389	342,466,388	348,682,806	354,940,487
kW	1,846,057	1,884,533	1,921,178	1,959,852	1,995,427	2,031,238
USL						
Customers	1,857	1,857	1,857	1,857	1,857	1,857
Connections	3,047	3,039	3,031	3,023	3,014	3,006
kWh	11,620,990	11,397,660	11,174,331	10,951,001	10,727,671	10,504,342
Sentinel						
Customers	248	248	248	248	248	248
Connections	407	401	395	389	383	378
kWh	455,814	437,397	418,980	400,564	382,147	363,731
kW	1,294	1,241	1,185	1,135	1,083	1,030
Street Lighting						
Customers	4	4	4	4	4	4
Devices	52,412	52,384	52,356	52,328	52,300	52,273
kWh	39,744,804	39,694,810	39,602,538	39,651,553	39,629,670	39,610,413
kW	110,065	110,006	109,948	109,890	109,831	109,773
Standby						
kW	281,814	290,976	300,137	309,299	318,460	327,622
Total						
Customers	241,692	243,319	245,123	247,036	249,021	250,909
Customers/Connections/Devices	295,449	297,034	298,796	300,668	302,610	304,456
kWh	4,720,212,823	4,712,295,573	4,716,078,768	4,706,567,248	4,703,656,447	4,699,541,403
kW from applicable classes	7,979,551	8,027,466	8,056,840	8,099,828	8,130,739	8,161,782

Table 3: Absolute Variance between the Forecasted Volumes and Customers 2014 - 2019 Using Most Recent Conference Board Forecasts vs. Forecasted Volumes and Customers 2014 – 2019 as filed in Exhibit 3, Tab 2, Schedule 1, Page 2

Customer Class	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Residential						
Customers	(51)	(225)	(457)	(696)	(933)	(1,166)
kWh	4,410,059	3,508,852	3,560,934	4,843,285	3,389,309	3,062,296
GS < 50 kW						
Customers	(3)	(12)	(22)	(32)	(42)	(52)
kWh	(968,469)	(1,225,444)	(1,296,114)	(1,437,583)	(1,490,075)	(1,567,217)
GS > 50 kW						
Customers	(9)	(17)	(20)	(17)	(13)	(12)
kWh	(3,507,278)	(4,152,204)	(3,877,871)	(3,806,487)	(3,319,583)	(2,926,647)
kW	(9,726)	(11,516)	(10,704)	(10,546)	(9,194)	(8,119)
Large Use (1)						
Customers	0	0	0	0	0	0
kWh	(0)	(182,373)	47,876	284,290	658,134	978,538
kW	0	(423)	111	660	1,528	2,271
Large Use (2)						
Customers	0	0	0	0	0	0
kWh	(0)	(222,532)	58,417	346,890	803,055	1,194,012
kW	0	(1,274)	334	1,985	4,596	6,833
USL						
Customers	0	0	0	0	0	0
Connections	0	0	0	0	0	0
kWh	0	0	0	0	0	0
Sentinel						
Customers	0	0	0	0	0	0
Connections	0	0	0	0	0	0
kWh	0	0	0	0	0	0
kW	0	0	0	0	0	0
Street Lighting						
Customers	0	0	0	0	0	0
Devices	0	0	0	0	0	0
kWh	0	0	0	0	0	0
kW	0	0	0	0	0	0
Standby						
kW	0	0	0	0	0	0
Total						
Customers	(64)	(254)	(499)	(744)	(989)	(1,231)
Customers/Connections/Devices	(64)	(254)	(499)	(745)	(988)	(1,230)
kWh	(65,689)	(2,273,701)	(1,506,757)	230,395	40,839	740,982
kW from applicable classes	(9,727)	(13,212)	(10,258)	(7,901)	(3,071)	985

Table 4: Percentage Variance between the Forecasted Volumes and Customers 2014 - 2019 Using Most Recent Conference Board Forecasts vs. Forecasted Volumes and Customers 2014 – 2019 as filed in Exhibit 3, Tab 2, Schedule 1, Page 2

Customer Class	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Residential						
Customers	(0.02%)	(0.10%)	(0.21%)	(0.31%)	(0.41%)	(0.51%)
kWh	0.27%	0.22%	0.22%	0.30%	0.21%	0.19%
GS < 50 kW						
Customers	(0.02%)	(0.07%)	(0.12%)	(0.17%)	(0.23%)	(0.28%)
kWh	(0.16%)	(0.21%)	(0.22%)	(0.25%)	(0.26%)	(0.27%)
GS > 50 kW						
Customers	(0.41%)	(0.77%)	(0.90%)	(0.74%)	(0.58%)	(0.54%)
kWh	(0.19%)	(0.22%)	(0.21%)	(0.21%)	(0.18%)	(0.16%)
kW	(0.19%)	(0.23%)	(0.21%)	(0.21%)	(0.18%)	(0.16%)
Large Use (1)						
Customers	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kWh	(0.00%)	(0.07%)	0.02%	0.10%	0.23%	0.34%
kW	0.00%	(0.07%)	0.02%	0.10%	0.23%	0.34%
Large Use (2)						
Customers	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kWh	(0.00%)	(0.07%)	0.02%	0.10%	0.23%	0.34%
kW	0.00%	(0.07%)	0.02%	0.10%	0.23%	0.34%
USL						
Customers	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Connections	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Sentinel						
Customers	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Connections	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kW	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Street Lighting						
Customers	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Devices	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kW	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Standby						
kW	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total						
Customers	(0.03%)	(0.10%)	(0.20%)	(0.30%)	(0.40%)	(0.49%)
Customers/Connections/Devices	(0.02%)	(0.09%)	(0.17%)	(0.25%)	(0.33%)	(0.40%)
kWh	(0.00%)	(0.05%)	(0.03%)	0.00%	0.00%	0.02%
kW from applicable classes	(0.12%)	(0.16%)	(0.13%)	(0.10%)	(0.04%)	0.01%

Table 5: Revenue Requirement Comparison (2015 – 2019)

	2015	2016	2017	2018	2019
Base Revenue Requirement (As Filed)	$112,956,026	$118,628,501	$121,743,444	$123,920,317	$127,881,899
Base Revenue Requirement (Per 3-EP-72TC)	$112,953,875	$118,627,064	$121,743,830	$123,920,506	$127,882,984
Difference	$2,151	$1,437	($386)	($188)	($1,085)

4-Energy Probe-73TC

Ref: Exhibit 4, Tab 2, Schedule 2, Table 4-17

Table 4-17 shows the new business requirements actually incurred in 2011. Were any of these new business requirements included in the Board approved 2011 figure?

Response:

Horizon Utilities confirms that the three New Business Requirements (“NBR”) listed in 2011 in Table 4-17 were included in the 2011 Application.

4-Energy Probe-74TC

Ref: 4-Energy Probe-27d&e

The response to part (d) indicates that the cost of the KPMG report was $27,000 and was incurred in 2013. The response to part (e) indicates that Horizon plans to amortize this cost over 2015 through 2019.

a) Please confirm that the total cost of the KPGM report is $27,000, so the amortized amount in each of 2015 through 2019 is $5,400.

b) Please confirm that the $27,000 shown for 2013 is not included in Table 4-20 for 2013, but is reflected in the 2015 through 2019 figures.

Response:

a) Horizon Utilities confirms that the cost of the KPMG report of $27,000 is amortized over the 2015 – 2019 years at $5,400 per year.

b) Horizon Utilities confirms that the $27,000 in not included in Table 4-20, but is reflected in the 2015 – 2019 years.

4-Energy Probe-75TC

Ref: 4-Energy Probe-28

Please provide the number of major storm events for each of 2011 through 2013 and year to date in 2014.

Response:

Horizon Utilities experienced 1 major storm in 2011, 2 major storms in 2012, and 2 major storms in 2013 as shown in response to Interrogatory 2-VECC-34. Horizon Utilities has not experienced a major storm to date in 2014.

4-Energy Probe-76TC

Ref: 4-Energy Probe-29

The response indicates that the updated 2014 forecast for total compensation is lower by about $1.6 million from the original forecast. How much of this reduction is related to a decrease in the amount expensed and how much is related to a decrease in the amount capitalized?

Response:

Of the $1.6M reduction in total compensation from the original forecast, $1.2M relates to a decrease in the amount expensed and $0.4M relates to a decrease in the amount capitalized.

4-Energy Probe-77TC

Ref: 4-Energy Probe-41

Please explain when any change in tax rates for 2015 would be determined by the Board.

Response

Changes in tax rates are determined through legislative changes enacted by the Federal or Ontario Government with applicability as specified in such legislation. Horizon Utilities assumed that such changes would affect its proposed rate adjustments in the application as of their effective dates.

8-Energy Probe-78TC

Ref: 8-SIA-32

a) Please provide all the information used in Schedule 11-2 to determine the calculated rates shown in Table 1.

b) Do wage rates make up a significant component in how these rates are set? What other costs are used in the determination of these rates?

c) What wage rates (year) were used in determining the current rates for the services shown in Table 1?

Response:

a) In Attachment 1, Horizon Utilities provides all the information used in Schedule 11-2 to determine the calculated rates shown in Table 1.

b) Yes, as labour costs make up a majority of the costs that determine these rates. However, Horizon Utilities did not update the hours required to deliver these services, and thus cannot represent that the calculated labour costs are consistent with the actual labour costs to deliver these services. Vehicle costs and “other” costs are also used in the Board’s Schedule 11-2 calculations, making up the remainder of the costs that determine these rates.

c) The current rates for the services shown in Table 1 are aligned with the standard amounts provided in Schedule 11-2 of the Board’s Distribution Rate Handbook (“DRH”). Horizon Utilities could not identify in the DRH the source of the wage rates used in determining the standard amounts for these rates, and thus cannot state which year’s wage rates were used in this determination.

Responses to School Energy Coalition Technical Questions

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1-SEC-53TC

[1-SEC-2] Please explain the zero-based approach. Please explain how top-down limits are placed on budgets, if they are. Please explain how the first year budget is used as the basis for the subsequent year budgets, including how economies of scale, changes in workforce demographics, and effects of capital spending are taken into account.
Response:

A zero-based approach to budgeting means the forecast for the subject year of the financial plan does not begin with default amounts taken from prior year actuals or the current year financial plan or forecast. Rather, each detailed line item is to be justified in terms of the future year's anticipated requirements. Past history may provide guidance but does not constitute a substitute for appropriate justification of costs.

Additionally, the first year of the operating budget only influences subsequent years to the extent that activities are recurring or related amounts generally change only with respect to inflation or where history is often a basis for forecasting (e.g., payroll, benefits, elements of other revenue, etc.). Otherwise, each year of the term of the financial plan is based on corresponding capital and operating business plans. Capital budgets are prepared using a zero-based approach for each year of the plan term. Overall, the plans for each year are expected to align to the strategic objectives of Horizon Utilities.

Top-down limits are established with respect to certain parameters (e.g. headcount, payroll inflation, etc.) but not in terms of absolute dollar amounts. This notwithstanding, customer impacts, the availability of supporting regulated revenue cash flow, and corporate liquidity heavily influence the outcome of the process.

Aggregated budget amounts are compared to the prior plan's forecast for the same year i.e. year 1 (2014) of the 2014 budget is compared to year 2 of the 2013 budget, to ensure any material changes to the previous plan are well understood in terms of changes to assumptions or expected requirements, and are aligned with productivity targets. As described above, potential future rate impacts to customers are also considered – revenue requirements are derived for each year of the plan term based on underlying costs. Productivity factors are also reviewed to ensure costs increase are appropriately managed/contained through productivity initiatives undertaken each year. Also, pro-forma statements are analyzed for consistency with the financial capacity, debt covenants and performance targets of the organization. Based on the findings of these analyses, final budget adjustments are generally dictated in a top-down manner.

1-SEC-54TC

[1-SEC-8 and 1-Staff-4] Please review the first attachment to these question, a list of Efficiency Assessments and other data for Ontario LDCs, a subset of the information in the PEG Benchmarking Update filed August 15, 2014, and confirm that the data for the Applicant is accurate. The data shows that the Applicant's efficiency has been declining over the last four years. Please provide details of the steps the Applicant is taking to ensure that this decline will be halted and then reversed, and to ensure that costs during each of the years of the IRM period will not exceed benchmark costs.

Response:

Horizon Utilities cannot confirm the accuracy of the data used by PEG in its August 15, 2014 update. Horizon Utilities believes that the PEG analysis of its data and efficiency are inaccurate for two reasons:

- There has been no attempt by PEG to normalize Horizon Utilities' data with respect to its transition to IFRS in 2012. As a consequence, OM&A rises significantly in 2012 and 2013 as a result of this transition. As you may appreciate, the PEG model is very complex and not easy to manipulate. However, Horizon Utilities has attempted normalization adjustments that indicate it should remain in the second cohort. This notwithstanding, Horizon Utilities cannot confirm the accuracy of its own analysis of the PEG model;
- There also appears to be some inconsistency in the manner that PEG has used to address smart meter costs in OM&A.

Horizon Utilities made Board staff aware of this matter on Thursday, August 14th and is working with them towards resolution.

The SEC attachment reference identifies a rising efficiency trend for Horizon Utilities from 2010 (-13.0%) to 2011 (-13.7%) thereafter declining in 2012 (-6.9%) and 2013 (-5.5%). The data in 2012 and 2013 is the subject of review as previously identified. Until this is resolved, Horizon Utilities cannot accept an assertion that its efficiency has declined in those years nor can it accept the three year average.

Horizon Utilities has and continues to undertake productivity initiatives and other strategies to deliver customer service at a reasonable cost consistent with some of its particular circumstances described in Exhibit 1. Customer growth is largely outside the control of Horizon Utilities and, as such, its low growth service territory is a constraint on achieving efficiency as measured by the PEG econometric analysis.

1-SEC-54TC Attachment 1 – Efficiency Assessment 2010 – 2013

		Efficiency Assessment						
Company	Year	2010	2011	2012	2013	Three Year	Cost per Customer	Cost per km of Line
HYDRO HAWKESBURY INC.	2013	-61.8%	-59.4%	-55.8%	-51.1%	-55.5%	284	23,045
WASAGA DISTRIBUTION INC.	2013	-46.8%	-46.3%	-37.8%	-41.6%	-42.1%	407	20,238
HEARST POWER DISTRIBUTION COMPANY LIMITED	2013	-26.3%	-30.1%	-28.4%	-33.1%	-30.6%	414	16,980
HALTON HILLS HYDRO INC.	2013	-27.2%	-24.9%	-27.5%	-35.7%	-29.5%	642	9,034
E.L.K. ENERGY INC.	2013	-28.2%	-26.2%	-25.4%	-33.2%	-28.3%	401	29,697
NORTHERN ONTARIO WIRES INC.	2013	-38.5%	-35.7%	-25.8%	-21.5%	-27.6%	687	11,268
HALDIMAND COUNTY HYDRO INC.	2013	-27.6%	-24.1%	-18.7%	-23.7%	-22.2%	681	8,310
COOPERATIVE HYDRO EMBRUN INC.	2013	-19.3%	-16.9%	-26.4%	-18.9%	-21.2%	568	39,819
KITCHENER	2013	-22.9%	-22.8%	-20.7%	-19.3%	-21.1%	466	22,062
NEWMARKET	2013	-14.6%	-21.0%	-19.5%	-19.5%	-20.1%	543	22,272
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATI(	2013	-22.6%	-21.8%	-15.5%	-19.3%	-18.9%	612	14,642
OSHAWA PUC NETWORKS INC.	2013	-21.7%	-18.0%	-14.5%	-17.4%	-16.7%	505	27,050
MILTON HYDRO DISTRIBUTION INC.	2013	-4.1%	-3.0%	-37.6%	-4.5%	-15.7%	654	22,402
ESSEX POWERLINES CORPORATION	2013	-17.0%	-17.1%	-12.6%	-17.2%	-15.7%	482	29,323
GRIMSBY POWER INCORPORATED	2013	-23.1%	-18.6%	-9.6%	-16.9%	-15.2%	538	23,739
WELLAND HYDRO-ELECTRIC SYSTEM CORP.	2013	-19.6%	-16.2%	-10.4%	-15.2%	-14.0%	472	23,533
LAKEFRONT UTILITIES INC.	2013	-14.7%	-12.5%	-18.7%	-7.4%	-12.9%	465	39,825
ENERSOURCE HYDRO MISSISSAUGA INC.	2013	-9.5%	-16.1%	-9.5%	-10.7%	-12.3%	692	26,742
Entegrus Powerlines	2013	-13.1%	-13.4%	-10.9%	-12.5%	-12.3%	531	22,407
LONDON HYDRO INC.	2013	-16.8%	-10.1%	-11.1%	-11.0%	-10.8%	466	24,430
LAKELAND POWER DISTRIBUTION LTD.	2013	-7.5%	-10.0%	-13.6%	-6.4%	-10.1%	700	22,852
RIDEAU ST. LAWRENCE DISTRIBUTION INC.	2013	-10.6%	-13.8%	-6.7%	-7.2%	-9.3%	489	27,552
HORIZON UTILITIES CORPORATION	2013	-13.0%	-13.7%	-6.9%	-5.5%	-8.8%	499	35,054
BURLINGTON HYDRO INC.	2013	-7.6%	-7.1%	-9.0%	-7.5%	-8.0%	587	25,773
HYDRO ONE BRAMPTON NETWORKS INC.	2013	-5.8%	-7.4%	-9.2%	-5.7%	-7.8%	586	27,565
COLLUS POWER CORPORATION	2013	-8.2%	-9.5%	-1.2%	-12.3%	-7.7%	500	23,849
KENORA HYDRO ELECTRIC CORPORATION LTD.	2013	-11.5%	-4.6%	-5.2%	-11.2%	-6.8%	532	30,201
HYDRO 2000 INC.	2013	-14.8%	-12.2%	-0.8%	-1.0%	-4.7%	531	30,838
WHITBY HYDRO ELECTRIC CORPORATION	2013	0.4%	-3.0%	-7.0%	-0.9%	-4.1%	642	24,806
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	2013	-7.1%	-6.2%	-2.4%	-2.8%	-3.9%	732	14,168
CAMBRIDGE and NORTH DUMFRIES HYDRO INC.	2013	-10.1%	-7.8%	-3.3%	0.5%	-3.7%	624	28,714
ORILLIA POWER DISTRIBUTION CORPORATION	2013	-3.5%	-1.9%	-3.7%	-4.7%	-3.5%	591	32,280
VERIDIAN CONNECTIONS INC.	2013	-4.7%	-4.5%	2.4%	-4.5%	-2.3%	529	23,757
CENTRE WELLINGTON HYDRO LTD.	2013	-8.7%	-4.9%	0.4%	0.4%	-1.5%	614	27,271
POWERSTREAM INC.	2013	-7.4%	-6.4%	1.2%	3.0%	-1.0%	653	29,912
WESTARIO POWER INC.	2013	-3.1%	-0.2%	-1.4%	2.2%	0.2%	550	24,220
ST. THOMAS ENERGY INC.	2013	-6.4%	-4.5%	6.8%	-0.3%	0.6%	533	33,412
ORANGEVILLE HYDRO LIMITED	2013	-2.7%	1.6%	0.8%	0.1%	0.7%	577	32,555
BRANTFORD POWER INC.	2013	3.8%	-2.5%	4.7%	0.7%	0.9%	507	39,373
NORFOLK POWER DISTRIBUTION INC.	2013	-1.8%	-2.6%	6.0%	1.2%	1.5%	689	16,915
OTTAWA RIVER POWER CORPORATION	2013	-2.9%	2.7%	0.0%	4.3%	2.3%	505	32,410
NIAGARA-ON-THE-LAKE HYDRO INC.	2013	7.6%	6.5%	2.7%	-0.7%	2.7%	699	18,516

KINGSTON HYDRO CORPORATION	2013	0.1%	2.2%	2.4%	3.7%	2.8%	517	38,667
SIOUX LOOKOUT HYDRO INC.	2013	0.6%	-1.4%	7.2%	2.9%	2.9%	802	7,845
GUELPH HYDRO ELECTRIC SYSTEMS INC.	2013	12.4%	14.7%	-2.0%	0.8%	4.2%	608	28,952
THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.	2013	9.6%	8.0%	-2.8%	8.2%	4.4%	585	25,631
HYDRO OTTAWA LIMITED	2013	-0.1%	-2.6%	7.8%	8.5%	4.5%	579	33,222
BLUEWATER POWER DISTRIBUTION CORPORATION	2013	-3.2%	1.7%	6.4%	5.9%	4.6%	646	29,017
NIAGARA PENINSULA ENERGY INC.	2013	5.4%	5.2%	10.2%	1.1%	5.4%	672	17,408
NORTH BAY HYDRO DISTRIBUTION LIMITED	2013	3.6%	5.5%	5.8%	5.4%	5.5%	614	25,228
WATERLOO NORTH HYDRO INC.	2013	-3.1%	6.4%	4.3%	10.6%	7.0%	728	25,066
PARRY SOUND POWER CORPORATION	2013	4.7%	4.6%	2.4%	13.9%	7.0%	805	21,599
ERIE THAMES POWERLINES CORPORATION	2013	14.9%	14.4%	3.9%	7.9%	8.7%	610	32,792
FORT FRANCES POWER CORPORATION	2013	14.8%	10.5%	11.7%	6.4%	9.6%	622	30,237
PUC DISTRIBUTION INC.	2013	-8.5%	-5.2%	13.4%	22.7%	10.2%	687	30,950
GREATER SUDBURY HYDRO INC.	2013	-2.4%	14.1%	16.7%	4.8%	11.9%	560	26,887
OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.	2013	7.6%	12.4%	10.6%	13.8%	12.0%	730	26,377
BRANT COUNTY POWER INC.	2013	15.6%	22.4%	11.5%	5.5%	13.0%	731	13,939
CANADIAN NIAGARA POWER INC.	2013	16.4%	15.6%	10.0%	13.8%	13.2%	726	20,275
TILLSONBURG HYDRO INC.	2013	13.5%	10.7%	12.2%	19.5%	14.1%	736	32,796
PETERBOROUGH DISTRIBUTION INCORPORATED	2013	14.0%	15.6%	13.2%	14.5%	14.4%	562	35,731
WELLINGTON NORTH POWER INC.	2013	7.4%	18.0%	12.8%	17.7%	16.1%	785	38,175
ENWIN UTILITIES LTD.	2013	17.8%	16.8%	23.9%	10.3%	16.9%	652	48,500
RENFREW HYDRO INC.	2013	15.3%	18.3%	18.3%	15.7%	17.4%	561	39,493
ATIKOKAN HYDRO INC.	2013	14.9%	7.7%	32.9%	11.6%	17.5%	908	16,430
MIDLAND POWER UTILITY CORPORATION	2013	16.4%	17.0%	19.6%	18.6%	18.2%	662	34,376
FESTIVAL HYDRO INC.	2013	20.5%	18.0%	20.2%	19.6%	19.2%	627	49,466
CHAPLEAU PUBLIC UTILITIES CORPORATION	2013	17.5%	14.8%	24.0%	20.5%	19.8%	653	30,175
WOODSTOCK HYDRO SERVICES INC.	2013	33.5%	32.9%	29.0%	28.1%	30.0%	739	48,418
WEST COAST HURON ENERGY INC.	2013	14.4%	16.0%	34.8%	41.4%	30.7%	820	50,545
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	2013	41.7%	47.7%	45.1%	48.4%	47.0%	924	66,793
HYDRO ONE NETWORKS INC.	2013	58.6%	57.3%	58.7%	27.6%	47.8%	1,046	10,682
ALGOMA POWER INC.	2013	62.0%	68.1%	66.4%	71.2%	68.5%	1,952	12,302

1-SEC-55TC

[1-Staff-3] Please confirm that, under the Applicant's proposal, there are no regulatory limits on the amount the Applicant can spend on capital, whether above or below the forecasts in the Application.

Response:

Horizon Utilities does not confirm that there are no regulatory limits on the amount spent on capital. As a very practical matter, capital expenditures are financed by regulated cash flow. Consequently, the level of regulated cash flow ultimately dictates the affordability of capital programs.

1-SEC-56TC

[1-Staff-6] Please explain more fully the proposed materiality threshold for reopeners, and how it would operate in practice.

Response:

This question was answered in response to Technical Conference Question 1-CCC-42TC and is repeated below.

Events that have a cost impact over the term of the Application greater than the materiality threshold ($564,780) calculated in Exhibit 1, Tab 6, Schedule 1, individually or cumulatively, would be included in the annual update. For example, if there was one incident that exceeded materiality or if there was a number of smaller incidents that accumulate to the materiality threshold, these would be included in the annual update process for reopeners.

Additionally, an event in a particular year resulting in a cost impact above materiality across the remaining IR years would be included in the annual update.

1-SEC-57TC

[1-Staff-8, p. 3] Please explain why the Applicant should have greater rate increases than the "many other distributors. confronted with similar requirements". Please identify how the responses of those distributors to these requirements differ from the response of the Applicant.

Response:

Horizon Utilities is somewhat confused by the question as 1-Staff-8 p. 3 does not provide any comparative rate increases with other distributors.

Horizon Utilities has not filed such evidence and cannot confirm that its' rate adjustments are greater than "many other distributors confronted with similar requirements". Horizon Utilities is not aware of any evidence it has filed with respect to responses of other distributors regarding rate adjustments and cannot comment further on this question.

1-SEC-58TC

[1-Staff-9] Please confirm that average annual productivity under the previous IR, 2011-2014 was $1,247,500, while proposed average annual productivity under Custom IR, 2015-2019, is $331,000 per year.

Response:

Horizon Utilities has corrected the productivity results that framed 1-Staff-9 as follows:

	Incremental Productivity			Corrected Incremental Productivity	
	Year	Productivity		Year	Productivity
	2011	$ 75,000		2011	$ 77,122
	2012	$ 1,465,000		2012	$ 1,397,830
	2013	$ 1,990,000		2013	$ 1,993,843
	2014	$ 1,460,000		2014	$ 1,385,007
	2015	$ 1,185,000		2015	$ 1,280,898
	2016	$ 160,000		2016	$ 165,600
	2017	$ 60,000		2017	$ 60,000
	2018	$ 100,000		2018	$ 100,000
	2019	$ 150,000		2019	$ 150,000
Average 2011 to 2014		$ 1,247,500	Average 2011 to 2014		$ 1,213,450
Average 2015 to 2019		$ 331,000	Average 2015 to 2019		$ 351,300

Horizon Utilities can advise that the average annual productivity under the previous application period was $1,213,451 annually as compared to the average of $351,300 annually during the custom IR timeframe of 2015 to 2019 as noted in the table created by Board Staff in 1-Staff-9.

Sustained productivity achievement and the additional of incremental and new initiatives are estimated to produce total productivity gains of $4.9MM, $6.1MM, $6.3MM, $6.3MM, $6.4MM and $6.4MM as of 2014, 2015, 2016, 2017, 2018, 2019 respectively as referenced in Exhibit 4, Tab 3, Schedule 4, Page 3 or 40.

1-SEC-59TC

[1-Staff-11, Table 1] Please confirm that, but for these projects, SAIDI would be in aggregate 2.906 higher.

Response:

Horizon Utilities cannot confirm that the SAIDI would be in aggregate 2.906 higher. The SAIDI values listed in 1-Staff-11 Table 1 are not intended to be aggregated in this manner.

1-SEC-60TC

[1-Staff-11, p. 5] Please advise what savings resulting from "reduction in outages. and decreased emergency and reactive maintenance" have been assumed in the Application, and show where those assumed savings are reflected in the cost forecasts.

Response:

Horizon Utilities expects emergency and reactive costs to increase over the rate plan term as stated in Exhibit 4, Tab 3, Schedule 3, beginning on page 62. However, Horizon Utilities expects to experience some O&M savings as a result of increased investment in system renewal, specifically through the 4kV and 8kV Renewal program, as referred to in Horizon Utilities response to Interrogatory 2-SEC-20 c). A reduction in the number of outages, and further reductions in reactive repair costs are expected but these cannot be quantified at this time as explained in response to Interrogatory Staff-11, page 5.

1-SEC-61TC

[1-Staff-12, p. 4] Please explain the 30% per annum data growth rate. Please provide the actual rate of data growth in each of the last five years.

Response:

Since 2009, Horizon Utilities has been experiencing annual data growth rates in excess of 30% driven by the following:

- Major implementations of new applications to support business requirements:
    - Geospatial Information System ("GIS") Renewal (Exhibit 2, Tab 6, Schedule 1, page 70);
    - Outage Management System ("OMS") (Exhibit 2, Tab 6, Schedule 1, page 72);
- Other new applications to support business requirements:
    - ABC/BI Financial Analysis Data Warehouse;
    - Budget and Forecasting System;
    - Primavera Planning and Scheduling System;
    - CYME Distribution System Planning;
    - Mobile work order management;
    - Microsoft SharePoint Enterprise Content Management;
    - KnowledgeNet Learning Management System;
- Incremental annual growth in data from AMI transactions (2.1 billion per year); user email and data files; and data stored in the SharePoint Enterprise Content Management system.

The actual per annum data growth rates for 2010 to 2014 (July) are:

- 2010 37%
- 2011 38%
- 2012 41%
- 2013 38%
- 2014 28% (January to July)

1-SEC-62TC

[1-Staff-15, Table 1] Please split this table into savings in OM&A, and savings in capital, and for the capital component provide an annual estimate of the revenue requirement impact.

Response:

The information contained in Table 1 in the response to Interrogatory 1-Staff-15 provides a summary of operating cost reductions and productivity/capacity improvements. The table does not contain capital components. Horizon Utilities provides the following table that summarizes the operating cost reductions included in Table 1 of the response to Interrogatory 1-Staff-15.

Table 1-OM&A Savings

Department	Initiative	2011 Actual	2012 Actual	2013 Actual	2014 Test Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Construction & Maintenance	Planning and Scheduling Initiative	$ -	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000
Construction & Maintenance	Outsourcing	$ -	$ -	$ -	$ 200,000	$ 300,000	$ 400,000	$ 400,000	$ 400,000	$ 400,000
Total Construction & Maintenance		**$ -**	**$ 100,000**	**$ 100,000**	**$ 300,000**	**$ 400,000**	**$ 500,000**	**$ 500,000**	**$ 500,000**	**$ 500,000**
Information Systems & Technology	IFS ERP Phase 1	$ -	$ -	$ 60,000	$ 170,000	$ 170,000	$ 170,000	$ 170,000	$ 170,000	$ 170,000
Information Systems & Technology	IFS ERP Phase 2	$ -	$ -	$ -	$ 30,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000
Total Information Systems & Technology		**$ -**	**$ -**	**$ 60,000**	**$ 200,000**	**$ 220,000**	**$ 220,000**	**$ 220,000**	**$ 220,000**	**$ 220,000**
Customer Services	E-mobile	$ 25,000	$ 180,000	$ 220,000	$ 390,000	$ 410,000	$ 410,000	$ 410,000	$ 410,000	$ 410,000
Customer Services	Customer Service - Outsourcing	$ -	$ -	$ 60,000	$ 70,000	$ 60,000	$ 70,000	$ 80,000	$ 90,000	$ 100,000
Customer Services	Customer Service - Miscellaneous	$ -	$ 175,000	$ 220,000	$ 240,000	$ 260,000	$ 280,000	$ 300,000	$ 320,000	$ 340,000
Total Customer Services		**$ 25,000**	**$ 355,000**	**$ 500,000**	**$ 700,000**	**$ 730,000**	**$ 760,000**	**$ 790,000**	**$ 820,000**	**$ 850,000**
Supply Chain Management	Fleet Initiatives	$ -	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000
Supply Chain Management	Procurement Initiatives	$ -	$ -	$ -	$ 30,000	$ 40,000	$ 40,000	$ 40,000	$ 50,000	$ 50,000
Supply Chain Management	Facilities Initiatives	$ -	$ -	$ 20,000	$ 30,000	$ 40,000	$ 40,000	$ 50,000	$ 50,000	$ 40,000
Total Supply Chain Management		**$ -**	**$ 20,000**	**$ 40,000**	**$ 80,000**	**$ 100,000**	**$ 100,000**	**$ 110,000**	**$ 120,000**	**$ 110,000**
Total Operating Expenditure Reductions		**$ 25,000**	**$ 475,000**	**$ 700,000**	**$ 1,280,000**	**$ 1,450,000**	**$ 1,580,000**	**$ 1,620,000**	**$ 1,660,000**	**$ 1,680,000**

Customer Services has made a correction to its OM&A savings. Please refer to Horizon Utilities' response to 1-VECC-64TC.

1-SEC-63TC

[1-Staff-16] With respect to the Applicant's productivity:

a. Please review the second attachment to these questions, a list of data for the twenty largest LDCs in the province. Please advise if any of the data relating to the Applicant appears to be inaccurate. Please provide a detailed plan for how the Applicant plans to improve its total factor productivity of -0.15% over the period of the Custom IR plan.

b. Attachment 1. Please confirm that the productivity amounts in the table include both OM&A and capital. Please explain how the capital productivity is integrated into the OM&A figures.

Response:

a) Horizon Utilities cannot validate the -0.15% total factor productivity value provided by SEC in the table. As well, Horizon Utilities is unaware of the source of the data in the table although it assumes that it refers to the PEG models. Consequently, Horizon Utilities does not accept the -0.15% total factor productivity value as a reference point for further improvement. Horizon Utilities has provided its known plans for productivity within the Application. Otherwise, Horizon Utilities cannot provide detailed plans with respect to initiatives that it has yet to conceive.

The computations in the table with respect to 2012 OM&A and Capital Expenditure changes appear to be based on 2012 MIFRS values and 2007 CGAAP values. The latter values would, of course, need to be restated on an MIFRS basis to provide a faithful and meaningful comparison and analysis.

I refer SEC to our previous response to 1-SEC-54TC with respect to Horizon Utilities concerns with respect to the PEG analysis of its data and efficiency.

Horizon Utilities has offered comparisons between 2012 and 2011; which are both stated in MIFRS.

Horizon Utilities makes reference to its filed evidence for Interrogatory 1-EP-3 and, more specifically, Attachment 3 to that interrogatory. This table provides MIFRS based actual customer and OM&A results for Horizon Utilities for 2012 and 2011 of $51,478,365, and $50,790,410, respectively. The corresponding OM&A per customer for 2012 and 2011 is $215.85 and $214.03, respectively. The corresponding year over year growth of OM&A per customer is relatively small at 0.85%.

The total 2012 and 2011 customers reported in this evidence is 238,488 and 237,305, respectively, or an increase of 0.50%.

The 2012 Audited Consolidated Financial Statements of Horizon Utilities Corporation reports 2012 and 2011 Distribution revenue of $97.185 million and $94.808MM, respectively. Using the customer numbers in 1-EP-3 Attachment 1, the corresponding 2012 and 2011 Revenue per Customer statistics are $407.51 and $399.52, respectively. The year over year increase in Revenue per Customer is relatively small at 2.00%.

Table 3 of Appendix 2-BA2 of the Application provides a fixed asset continuity for 2012 Actual MIFRS. The table reports a closing net book value of $369,861,076 for 2012. Table 2 of that same appendix reports a closing net book value of $326,151,640 for 2011. It is noteworthy that 2012 additions include an additional $10,000,000 Capital Contribution to Hydro One with respect to previous transformer station installations. 2012 and 2011 capital Assets per customer were $1,550.85 and $1,374.40. The year over year increase is 12.84%. Such increase would have been 10.34% in the absence of the capital contribution to Hydro One.

Horizon Utilities is unable to verify the CapAdds/Depn value in the SEC table as the underlying formula used to compute this statistic is not apparent.

b) Again, Horizon Utilities assumes that the data in SEC Attachment 1 is, at least in part, a faithful extraction from the PEG report and models. Based on its understanding of the PEG econometric analysis, Horizon Utilities confirms that the productivity amounts reported in the table include both OM&A and capital. However, Horizon Utilities is confused by the SEC question “Please explain how the capital productivity is integrated into the OM&A figures” and cannot provide such explanation.

1-SEC-64TC

[1-Energy Probe-3] Please provide a fuller explanation of the Attachments at the Technical Conference.

Response:

Horizon Utilities submits that it has provided full and comprehensive explanations of the attachments to its response to interrogatory 1-EP-3. Horizon Utilities would also direct SEC to its application evidence at Exhibit 1, Tab 2, Schedule 6, pages 24 through 31 under the heading OM&A Trend Analysis. The responses to interrogatories 1-Staff-8, 1-Staff-16, 1-SIA-7, 1-SIA-8, and 1-BOMA-7 may also be helpful references with respect to explanations of the attachments.

Beyond this, the question lacks sufficient specificity to guide Horizon Utilities on the nature of the “fuller explanation” sought by SEC.

2-SEC-65TC

[2-SEC-17] Please identify where institutional customers such as schools fit in Table 1. Please provide whatever data the Applicant has on the Value of Service applicable to schools.

Response:

Institutional customers such as schools would be considered Commercial customers in the context of calculating Value of Service ("VOS") as described in Horizon Utilities' response to Interrogatory 2-SEC-17.

2-SEC-66TC

[2-SEC-18, Attachment 2] Please provide a list of all institutional customers, including school boards, interviewed as part of the key account interviews. Please identify any representatives of school boards that participated in any focus groups. Please provide all written or online materials provided to customers who were interviewed individuals or in focus groups.

Response:

It seems that this question is a request for new information and not a clarification of the Work plan and Budget that was submitted in response to Interrogatory 2-SEC-18 Attachment 2. Horizon Utilities is concerned that the customers involved in the consultation understood the consultation process was confidential.

Horizon Utilities interprets institutional customers as Municipalities, Universities, Schools and Hospitals. Horizon Utilities can confirm that as part of the key account interviews, Horizon Utilities interviewed 8 institutional customers, 3 of which were school boards.

SEC may reach out to its clients to identify which school boards participated in interviews and if representatives of school boards participated in any focus groups.

Horizon Utilities provided customers who were interviewed or participated in focus groups with the link to the Online Distribution System Plan Workbook, http://www.horizonutilitiesworkbook.com as referenced in Exhibit 1, Tab 4, Schedule 1, Page 13 of 14, Table 1-22 and a copy of the Distribution System Plan Workbook as referenced in Exhibit 2, Appendix D of the DSP.

Horizon Utilities does not have any further information to provide in response to this question.

2-SEC-67TC

[2-SEC-19] Please provide a fuller explanation of Table 1 orally during the Technical Conference.

Response:

Horizon Utilities submits that it has provided full explanation in response to Interrogatory 2-SEC-19.

Beyond this, the question lacks sufficient specificity to guide Horizon Utilities on the nature of the “fuller explanation” sought by SEC.

2-SEC-68TC

[2-SEC-20(a)] Please explain the phrase "exclusive of productivity savings" and its impact.

Response:

Horizon Utilities included this phrase in the response to Interrogatory 2-SEC-20 to clarify that not a single major capital project will result in an actual reduction in operating costs exceeding the materiality threshold. Productivity savings not producing actual reductions in expenditures (e.g. capacity savings that provide the ability to perform a greater volume of work for the same expenditure) are not included in this assessment.

2-SEC-69TC

[2-SEC-20(c)] Please provide details of the $335,000 of savings. Please provide a table showing, for each year from 2011 to 2019, the number of stations, and the O&M related to those stations.

Response:

Horizon Utilities would like to clarify that the $335,000 of savings identified pertain to the 2015 to 2019 rate plan term and not 2011 to 2019 as identified in the question. The details of the $335,000 of savings are identified in the table below.

	2016	2017	2018	2019	Total
Thermography	$225	$675	$675	$1,800	$3,375
Oil Tests	$290	$1,450	$1,450	$3,480	$6,670
Bus Maintenance	$2,893	$23,148	$0	$23,148	$49,189
Partial Discharge	$3,356	$6,712	$0	$16,780	$26,848
Repairs/Janitorial/Service Agreements	$16,605	$49,815	$49,815	$132,840	$249,075
Total	**$23,370**	**$81,800**	**$51,940**	**$178,048**	**$335,157**

The number of substations being decommissioned per year is: two substations in 2016; two substations in 2017; and five substations in 2019.

2-SEC-70TC

[1-Staff-12, p. 5] Please identify all amounts included in capital budgets presented to the Board in prior years relating to building renovations that had not yet been completed by December 31, 2013.

Response:

There were no amounts for building renovations in the 2008 capital budget included in the 2008 CoS Application (EB-2007-0697) presented to the Board. The amounts budgeted in the 2011 capital budget and included in the 2011 CoS Application (EB-2010-0131) were completed by December 2013.

2-SEC-71TC

[2-Staff-17(c)] Please provide details of the "rate increases to fund system renewal" proposition approved by customers. Please advise which customer groups agreed with that proposition, in which proportions, and based on what level of rate increases for what level of system renewal. Please confirm that the key account customers, other than the LU(2) customers, agreed that they should pay higher rates so that Horizon could increase its system renewal spending.

Response:

Horizon Utilities did not specifically detail "rate increases to fund system renewal" in the customer consultation process. In the Residential ratepayer survey, customers were informed that in order to maintain the reliability of the local electricity system, the proposed 5 year plan would cost an estimated $228 million which included:

- $147 million to replace aging infrastructure;
- $41 million to maintain metering and connect new customers to the electricity system;
- $31 million to invest in tools, computers and software systems, vehicles and facilities needed to manage the electricity system; and
- $9 million for new technologies to make the system more efficient and reliable.

On page 21 of the Horizon Utilities' DSP Workbook, bill impacts associated with this increased costs was communicated as an average increase of 4.2% on the distribution portion of a residential customer's bill for the next five years. As referenced on page 5 of the Innovative Customer Consultation Report, 73% of residential customers either supported the increase or understood the need for the increase:

- The proposed rate increase is reasonable and I support it 32%
- I don't like it, but I think the proposed rate increase is necessary 41%
- The proposed rate increase is unreasonable and I oppose it 24%
- Don't know / Refuse 3%

As referenced on page 4, of the Innovative Customer Consultation Report, most participants (32 of 43) in the facilitated discussion groups with GS <50kW and GS >50kW supported or understood the need to increase rates by the proposed amount. The amount was referenced on page 21 of Horizon Utilities' DSP Workbook. It indicated a 4.2% increase on the distribution portion of customer's bill for the next five years for the GS <50kW customers and a 9.5% increase on the distribution portion of customer's bill for the next five years for the GS >50kW customers.

As referenced on page 6, of the Innovative Customer Consultation Report in Phase 4: Key Account Validation Interviews, "*most Key Accounts (6 of 9) gave Horizon Utilities permission to change rates by the proposed amount; with 5 of 9 saying they support the proposed rate change and 1 of the 9 saying they don't like but think it is necessary. Additionally, 3 of 9 respondents from the GS >50kW rate class who participated as Key Accounts believe the rate change is unreasonable and opposed it*."

2-SEC-72TC

[2-Staff-20(b)] Please confirm that, the longer the Productive Asset Investment Ratio for Distribution Plant remains high:

a. The average age of the Applicant's distribution plant declines;

b. The need to maintain a high Productive Asset Investment Ratio for Distribution Plant is reduced; and

c. The OM&A costs associated with operating and maintaining the distribution plant declines.

Response:

As identified in Horizon Utilities' response to Interrogatory 2-Staff-20 b) the Productive Asset Investment Ratio is defined as the ratio of Capital Expenditures versus Depreciation Expense. Companies with a ratio over 1.0 are typically expanding as more fixed assets are added than have depreciated over the same time. Horizon Utilities has assumed a "high" Productive Asset Investment Ratio to mean at the same levels identified in the response to Interrogatory 2-Staff-20 b).

a. Horizon Utilities confirms that the average age of its distribution plant will decline the longer the Productive Asset Investment Ratio for Distribution Plant remains high. The higher the Productive Asset Investment Ratio, the higher the value of capital expenditures for new assets in relation to NBV of existing assets and the faster the decline in the average age of distribution plant.

b. The need to maintain a high Productive Asset Investment Ratio corresponds to Horizon Utilities ongoing need to increase investment in the renewal of aging distribution system as identified in Horizon Utilities' response to Interrogatory 2-Staff-20. The longer the Productive Asset Investment Ratio for Distribution Plant remains high, the higher the investment in the renewal of aging distribution infrastructure. Once the backlog of assets requiring renewal is addressed, the requirement to maintain a high level of investment will decline. According to Horizon Utilities' projected 20-year expenditures, as shown in Exhibit 2, Tab 6, Schedule 1, Figure 2-2, the backlog of assets requiring renewal will not be addressed within the first 20 years.

c. Horizon Utilities does not confirm that the longer the productive asset investment ratio remains high that Operating and Maintenance costs ("O&M") decline. Horizon Utilities incurs capital expenditures which could increase O&M such as projects related to system access and system service. Horizon Utilities expects to experience some O&M savings as a result of increased investment in system renewal, specifically the 4kV and 8kV Renewal program, as referred to in Horizon Utilities' Interrogatory response to 2-SEC-20 c). However, full savings will not be realized until after the rate term plan, as identified on page 7 of the DSP filed as Appendix 2-4 of Exhibit 2. Additionally, operating cost increases are influenced by factors other than the level of capital expenditures, such as increased storm events and equipment failures.

4-SEC-73TC

[4-SEC-29] Please describe the reasons for the material variances between updated Tables 4-22 and 4-23, and the original tables.

Response:

The variance between 2014 budget as filed in the Application and the current forecast for 2014 is summarised in the table below, by program and cost centre:

Programs	2014 Bridge Year	2014 Bridge Year (based on five months actuals / seven months forecast)	Variance
Reference	**Table 4-22 and 4-23**	**4-SEC-29**	
Reporting Basis	**MIFRS**	**MIFRS**	
Executive			
Corporate	1,027,123	1,203,100	175,977
Sub-Total	**1,027,123**	**1,203,100**	**175,977**
Human Resources			
Corporate Services	483,350	479,026	(4,323)
Healthy Workplace & Safety	820,954	855,806	34,852
Human Resources	1,984,311	1,909,649	(74,662)
Sub-Total	**3,288,614**	**3,244,481**	**(44,134)**
Business Development & Corporate Communications			
Business Development - Executive			
Corporate Communications	1,127,509	1,154,675	27,166
Sub-Total	**1,127,509**	**1,154,675**	**27,166**
REGULATORY			
Regulatory Services	2,288,408	2,260,228	(28,180)
Sub-Total	**2,288,408**	**2,260,228**	**(28,180)**
Financial Services			
Financial Services	3,662,618	3,635,267	(27,351)
Sub-Total	**3,662,618**	**3,635,267**	**(27,351)**
IST			
Business Projects	704,536	889,233	184,697
PC Services	1,712,577	1,704,526	(8,051)
Business Applications	657,200	658,521	1,320
Information Systems and Technology	509,211	561,341	52,130
Cyber Security	498,930	479,591	(19,339)
Sub-Total	**4,082,455**	**4,293,211**	**210,757**
Customer Services			
Customer Care Intracompany Horizon	9,614,808	9,492,748	(122,060)
Customer Service and Customer Connections - Executive	-	-	-
Advance Meter Inventory/Meter Data Management & Repository	657,045	593,997	(63,048)
MV90	183,284	162,834	(20,450)
Sub-Total	**10,455,138**	**10,249,579**	**(205,559)**

Programs	**2014 Bridge Year**	**2014 Bridge Year (based on five months actuals / seven months forecast)**	**Variance**
Reference	**Table 4-22 and 4-23**	**4-SEC-29**	
Reporting Basis	**MIFRS**	**MIFRS**	
Customer Connections			-
Customer Connections	2,273,614	2,395,376	121,762
Meter Assets and Inside Service	784,348	658,744	(125,604)
Meter Sevice Providing	-	-	-
Smart Meters	-	-	-
Sub-Total	**3,057,962**	**3,054,120**	**(3,841)**
Utility Operations			-
Utility Operations	1,177,345	1,238,810	61,464
Sub-Total	**1,177,345**	**1,238,810**	**61,464**
Construction and Maintenance			-
Underground	3,304,290	2,520,588	(783,702)
Contractor Management	1,938,538	1,925,321	(13,217)
Overhead	5,046,085	5,927,602	881,517
Substations	851,250	853,042	1,792
Project Controls Office	556,010	464,699	(91,311)
Construction and Maintenance Services	234,446	314,287	79,841
Sub-Total	**11,930,619**	**12,005,539**	**74,920**
FACILITIES			-
Facilities - General	634,718	744,133	109,415
Building - Substations	961,132	915,737	(45,395)
Building - John St. Hamilton	978,914	1,086,195	107,281
Building - Nebo Rd. Hamilton	1,173,432	1,332,893	159,461
Building - Stoney Creek	329,326	428,006	98,680
Building - Vansickle Rd. St. Catharines	640,038	650,444	10,406
Sub-Total	**4,717,560**	**5,157,408**	**439,848**
Supply Chain Management			-
Procurement	853,214	944,477	91,263
Fleet	2,094,079	2,132,481	38,402
Logistics	1,926,703	1,737,620	(189,084)
Supply Chain	396,256	404,358	8,102
Sub-Total	**5,270,252**	**5,218,936**	**(51,316)**
Engineering and Operations			-
Network Assets	1,950,811	1,910,353	(40,457)
Network Operating	2,189,720	2,332,828	143,109
Network Records	2,472,786	1,861,369	(611,417)
Capital Projects	1,460,884	1,210,369	(250,515)
Engineering Operations & Operational Improvement	227,566	233,843	6,277
Sub-Total	**8,301,766**	**7,548,763**	**(753,004)**
Miscellaneous			0
Total	**60,387,369**	**60,264,118**	**(123,251)**

As shown in the table above, the current forecast for 2014 is not materially different from the Bridge Year forecast per the Application in totality.

4-SEC-74TC

[4-SEC-30] Please confirm that the Applicant expects to implement additional productivity initiatives during the IRM period, over and above those planned today and included in the Application.

Response:

The Applicant expects to investigate additional productivity initiatives during the IR period over and above those planned today and included in the Application. The Applicant cannot confirm any implementations in advance of evaluating the outcome of such investigations.

4-SEC-75TC

[4-SEC-34] Please identify the dollar impact of the IFRS (or MIFRS) accounting change for each year impacted.

Response:

Please refer to the table below for the dollar impact of the MIFRS accounting change on capitalized labour from 2011 to 2014.

	Actual 2011	Actual 2012	Actual 2013	Forecast 2014
Impact of MIFRS on Capitalized Compensation	$ 4,777,996	$ 4,769,057	$ 5,462,534	$ 6,364,519

4-SEC-76TC

[4-SEC-25, Attachment] With respect to the GIS Business Case:

a. P. 5. Please provide the dollar savings associated with the costs that are "lower on a per unit basis", and show where they are reflected in the cost forecasts in the Application. Please identify and quantify the increases in service levels forecast, and show where they are reflected in the Application.

b. P. 7. Please explain the first paragraph in "Financial Summary". Please identify the "improvements in efficiency" forecast, and show where they are reflected in the cost forecasts in the Application.

c. P. 9. Please provide the "GIS needs" document referred to.

d. P. 9. Please provide details on all of the "major IT upgrade projects" planned, and all incremental costs arising out of those initiatives.

e. P. 13. Please provide the dollar savings associated with the "dramatic savings in time and effort for field operations", and show where they are reflected in the cost forecasts in the Application.

f. P. 18. Please provide a list of "Horizon information systems" with which the GIS will not be interoperable.

g. P. 19-21. For each of the dollar amounts on these pages, please identify whether they are OM&A, or capital, and show where they are reflected in the relevant forecasts in the Application.

h. P. 21. Please confirm that each of the "annual benefits" are dollar savings that result in lower revenue requirement.

i. If any of the costs or benefits included in this business case are out of date, or have been updated, please provide the updated figures.

j. P. 22. Please provide a list of the "many improvements" the departments at Horizon are expecting from the GIS.

k. Please reconcile the savings in the business case with the response to 1-Staff-15, p. 2.

Response:

Horizon Utilities is unable to provide a response to parts (a) through (k) of this interrogatory. Horizon Utilities' description of the GIS Renewal Project, including total project costs and a description of the anticipated benefits, is provided starting on page 70 of Exhibit 2, Tab 6, Schedule 1 of the Application. The productivity improvements, in the form of organization capacity, are provided in the response to interrogatory 1-Staff-15(a).

Horizon Utilities' GIS Business Case, as provided in the response to Interrogatory 2-SEC-25, was developed in advance of Horizon Utilities' procurement process. Horizon Utilities identified the need to replace the end-of-life GIS system and engaged a 3rd party consultant to prepare a business case in support of the project. The potential project costs were estimates for budget purposes and were not reflective of the pricing received through the procurement process. The sources of potential benefits were high level estimates based upon the best available information at the time and anticipated project scope. Additionally, the business case was developed to support the required replacement of the GIS and does not reflect the actual project scope as developed through the procurement stage of the project. The actual project scope included the deployment of an Outage Management System ("OMS") to be integrated with the GIS. For the reasons listed above, the answers to parts (a) through (k) of this interrogatory would not be relevant to an assessment of this project and would provide no probative value to this process.

4-SEC-77TC

[1-Staff-12, p. 6] Please provide details of all OM&A savings that are assumed to arise due to the John Street repairs, including utility costs, repairs and maintenance, staff disruption, and other savings, and show where there savings have been reflected in the cost forecasts in the Application.

Response:

Table 1 below provides a summary of all OM&A savings that are assumed to arise from the planned building renovation projects at John Street. These savings have been contemplated in the costs forecasts in the Application, but such costs have not been reduced specifically by these amounts. There were no OM&A reductions in 2015. In the absence of the planned renovation projects at John Street, the forecasted costs would have been significantly higher than forecasted.

Table 1 - General Plant Capital Investments OM&A Reductions

Initiative General Plant Capital Investments :	2016	2017	2018	2019	Total	Total Benefits (ROI, Productivity or Efficiency measure)
Hughson Substation and John Street 5th Floor Renovations	$70,000	$70,000	$70,000	$70,000	$280,000	Operational cost savings due to the expected energy efficiencies expected from the replacement of high efficiency HVAC units, replacement of new windows and installation of insulation to the Hughson Substation building. In addition the annual asbestos testing to meet with Regulation would not be required as the removal of the asbestos is part of the project scope.
Building Security Replacement (John Street Building)		$20,000	$20,000	$20,000	$60,000	Operational cost savings from the reduction of third party security response to calls and repairs to security equipment and systems.
John Street Roof Replacement	$10,000	$10,000	$10,000	$10,000	$40,000	Operational cost savings from ongoing required repairs and patch work to existing roofs that would not be required once replaced.
John Street Window Replacement			$35,000	$35,000	$70,000	Operational cost savings due to expected energy efficiencies and reduction of required repairs to building structure and assets from water damage.
John Street 2nd Floor Renovation		$25,000	$25,000	$25,000	$75,000	Operational cost savings due to expected energy efficiencies from the installation of high efficiency lighting systems with motion sensors, installation of wall insulation and ongoing repairs of aging carpet.
John Street 6th Floor Renovation			$5,000	$5,000	$10,000	Operational cost savings due to expected energy efficiencies from the installation of high efficiency lighting systems with motion sensors, replacement of HVAC units and installation of wall insulation and ongoing repairs of aging carpet.
John Street Basement/Lobby Renovation				$5,000	$5,000	Operational cost savings due to expected energy efficiencies and water consumption reductions due to the replacement of existing lighting systems and washroom faucets and equipment.
Total General Plant Capital Investments	**$80,000**	**$125,000**	**$165,000**	**$170,000**	**$540,000**	

4-SEC-78TC

[1-Staff-15, p. 2] Please provide further details of the e-mobile productivity savings.

Response:

E-mobile was initiated in 2011 as a multi-year (4 year) project to develop a paperless work order system for meter-related service orders for field staff and to streamline and automate back-office processes. E-mobile was initiated as a result of the success using the electronic service order system to manage the mass deployment and installation of over 225,000 smart meters during the period 2007-2010.

Today, over 30,000 customer service field orders which include, meter changes, new installation of services, collection and reconnection activities and inspection related service orders are completed using e-mobile on an annual basis. Service orders are downloaded to the tablets from the Customer Information System ("CIS") for field agents. Service orders can be electronically prioritized with regard to routing to allow the agents to efficiently plan their day. Prior to the implementation of e-mobile, field staff were required to start and end their day at the office to pick-up and return their service orders to the office. With e-mobile, agents have the ability to start and end their day in the field and they can receive additional ad-hoc service orders as required throughout the day which provides additional productive time for each agent.

E-mobile also allows for the elimination of clerical work due to the reduction of manual paper processes.

There are customer benefits to the electronic service orders as agents have access to real-time customer information in the field.

Horizon Utilities has provided a further breakdown of e-mobile productivity in its response to 1-VECC-64TC.

4-SEC-79TC

[4-Staff-28, Table 2-28] Please provide details of how the Loss on Derecognition of PP&E has affected, or will affect, revenue requirement for ratemaking purposes in each of the years listed, and the basis for the financial and regulatory accounting treatments.

Response:

As provided in the Accounting Procedures Handbook ("APH"), Article 220, page 126 under Account 4362 - Loss from Retirement of Utility and Other Property *"This Account shall be charged with the loss from the retirement of property, plant and equipment or intangible asset"*. In the APH Article 315 page 9 it states *"Where a distributor has accounted for the amount of a gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings the distributor shall reclassify such gains and losses as depreciation expense and disclose the amount separately"*. These amounts have been disclosed separately in Table 4-78 in Exhibit 4, Tab 2, Schedule 2. For each of the rate years the revenue requirement impact of these losses, net of related proceeds, is $1,587,074, $2,286,304, $2,218,419, $2,387,296, and $2,613,609 in each of the years 2015 through 2019, respectively. Losses on derecognition of PP&E will affect revenue requirement for rate making purposes by an amount equal to the value of the loss.

On an external reporting basis, losses on disposition and early retirement of assets are reported separately in the financial statements as an expense.

4-SEC-80TC

[Ex.4-3-3-p.1] Please provide 2014 year-to-date actuals for Table 4-22 and 4-23.

Response:

As requested please find below updated information for Tables 4-22 and 4-23 for June 2014 Year-to-Date Actuals.

Programs	2014 Bridge Year (6 months actuals YTD)
Reporting Basis	MIFRS
Executive	
Corporate	616,934
Sub-Total	**616,934**
Human Resources	
Corporate Services	245,878
Healthy Workplace & Safety	264,073
Human Resources	792,880
Sub-Total	**1,302,831**
Business Development & Corporate Communications	
Corporate Communications	599,317
Sub-Total	**599,317**
Regulatory Affairs	
Regulatory Affairs	1,887,286
Sub-Total	**1,887,286**
Corporate Finance	
Corporate Finance	1,897,264
Sub-Total	**1,897,264**
IST	
Business Projects	560,226
PC Services	788,436
Business Applications	316,190
Information Systems and Technology	295,345
Cyber Security	232,682
Sub-Total	**2,192,878**
Customer Services	
Customer Care Intracompany Horizon	4,556,450
Customer Service and Customer Connections	-
Advance Meter Inventory/Meter Data Management & Repository	244,708
MV90	65,916
Sub-Total	**4,867,074**

Programs	**2014 Bridge Year (6 months actuals YTD)**
Reporting Basis	**MIFRS**
Customer Connections	
Customer Connections	1,064,097
Meter Assets and Inside Service	362,937
Meter Service Providing	-
Smart Meters	-
Sub-Total	**1,427,034**
Utility Operations	
Utility Operations	652,547
Sub-Total	**652,547**
Construction and Maintenance	
Underground	942,709
Contractor Management	884,837
Overhead	3,170,941
Substations	157,658
Project Controls Office	178,131
Construction and Maintenance Services	134,281
Sub-Total	**5,468,558**
FACILITIES	
Facilities - General	447,575
Building - Substations	448,361
Building - John St. Hamilton	477,566
Building - Nebo Rd. Hamilton	616,100
Building - Stoney Creek	159,189
Building - Vansickle Rd. St. Catharines	300,786
Sub-Total	**2,449,576**
Supply Chain Management	
Procurement	425,687
Fleet	1,114,055
Logistics	803,677
Supply Chain	176,867
Sub-Total	**2,520,285**
Engineering and Operations	
Network Assets	763,939
Network Operating	1,274,594
Network Records	518,998
Capital Projects	427,335
Engineering Operations & Operational Improvement	126,206
Sub-Total	**3,111,073**
Total	**28,992,659**

6-SEC-81TC

[6-SEC-38(d)] Please provide the Applicant's ranking in revenue per customer by rate class, using 2013 data. Please provide any data the Applicant has available comparing the vintage of its assets to the vintages of similar assets of other LDCs.

Response:

Rankings of average distribution revenue per customer by customer class can only have precision as a reliable comparative metric if the average billed kWh per customer in the class is the same for each LDC. With 73 LDCs in Ontario varying in customer size from 1,200 (Hydro 2000) to 1.2 million (Hydro One Networks), customer demographics across LDCs will be quite different. As a result, a metric of average revenue per customer needs to be assessed in the context of a metric of billed kWh per customer comparisons as well. The source data below is from the OEB's Annual Yearbook of Electricity Distributors 2013, published August 14, 2014.

Residential: Horizon Utilities ranks 25th lowest on average distribution revenue per customer and ranks 2nd lowest on average billed kWh of consumption per customer of 73 LDCs. Even with such a low volume of consumption per customer from the residential customer class, which would otherwise suggest Horizon Utilities' needs high average revenue per customer, there are 48 of 73 LDCs that require more revenue per customer than does Horizon Utilities.

General Service less than 50 kW: Horizon Utilities ranks 27th lowest on average distribution revenue per customer and 49th lowest on average billed kWh of consumption per customer of 72 LDC with filed data for 2013. Ranking lower on revenue per customer than billed kWh per customer against the sector suggests Horizon Utilities' customers in this class are, on balance, larger than the sector average for the class. This suggests Horizon Utilities' average revenue need per customer versus the sector is actually better than that represented in its 27th lowest ranking against other LDCs. Even at this ranking, there are 46 LDCs with a higher average revenue need in this class than Horizon Utilities.

General Service greater than 50 kW: Horizon Utilities ranks 43rd lowest on average distribution revenue per customer and 54th lowest on average billed kWh per customer of 73 LDCs. Any ranking based on either metric must come with the caveat that the OEB Yearbook data for this class also includes Large Use customers, which have greater than 5,000 kW of demand and Sub-transmission customers, some of which may have greater than 5,000 kW of demand. Only 23 of 73 LDCs have Large User customers and Horizon Utilities has 11 of the total of 132 Large User customers. With this context, ranking lower on average distribution revenue per customer than on average billed kWh of consumption again suggests that Horizon Utilities' GS > 50 kW customers are larger on balance, which would explain higher revenue outcome per customer. This suggests, first, that Horizon Utilities' average revenue per customer, while in the middle of the group of LDCs, is shaped by having larger customers on average than the class, and, second, that Horizon Utilities' average revenue need per customer versus the sector is actually better than that represented in its 43rd lowest ranking against other LDCs.

Unmetered Scattered Load: Horizon Utilities ranks 20th lowest on average distribution revenue per customer and 17th lowest on Billed kWh of the 68 LDCs with filed data.

The Applicant does not have any data comparing the vintage of its assets to other LDCs.

6-SEC-82TC

[6-SEC-39 and 6-SEC-40] Please confirm that no written materials were provided by KPMG to the Applicant relating to these analyses. If any written materials were provided, please provide copies. If no written materials were provided, please explain why.

Response:

Horizon Utilities confirms that no written material was provided by KPMG relating to these analyses as KPMG was not engaged to perform a review or audit of these specific analyses, therefore no reports were procured.

7-SEC-83TC

[7-SEC-44] Please confirm that, on average, GS>50 distribution bills would be increased, on an ongoing basis, by 11.7% as a result of the introduction of the LU(2) class.

Response:

Horizon Utilities does not confirm the above statement. Table 1 below provides a comparison of the distribution bill impact for a GS > 50 kW customer at 250 kW with and without the introductions of the LU (2) class.

Table 1: Distribution Bill Impacts at 250 kW

	2015	2016	2017	2018	2019
DX Bill Increase As Filed	22.26%	4.35%	2.34%	1.33%	2.68%
DX Bill Increase (No LU (2))	9.83%	4.28%	2.17%	1.28%	2.65%

Horizon Utilities wishes to further clarify that the evidence as presented in exhibit 7 shows that the introduction of the LU (2) class represents an improvement to the Cost Allocation process for Horizon Utilities. The increase in distribution rates from the introduction of this class should be seen as a correction to rates that are currently lower than they should be. In essence, the proposed LU (2) customers have been subsidizing the bills of many other rate classes under the current rate structure.

8-SEC-84TC

[8-SEC-51] Please confirm that, in light of the August 15, 2014 decision of the Board in EB-2013-0116 on fixed charges, the Applicant will keep the fixed charge for GS>50 at $302.77 throughout the IRM period, rather than move it further above the maximum of the range. Please provide the volumetric rates for each of the five years based on a fixed charge of $302.77 throughout.

Response:

Horizon Utilities has no changes to the Application as filed.

If the fixed charge of $302.77 was maintained throughout 2015 – 2019, the volumetric rates by year would be: $2.8042, $2.9559, $3.0675, $3.1644, $3.3085.

8-SEC-85TC

[8-Staff-32] Please explain how the proposed increases in fixed charges are consistent, for each class, with the demand-based fixed charges proposed as part of the Revenue Decoupling consultation.

Response:

The fixed charges proposed by Horizon Utilities are not consistent with the demand-based fixed charges proposed by the Board. Horizon Utilities is supportive of a fixed rate design solution, but further support the Board's Proposal 1 – a single monthly charge which is the same for all consumers within the rate class. As stated in response to 1-CCC-43TC, Horizon Utilities' position is that its cost structure is largely fixed relative to the number of customers. Consequently, a fixed charge makes sense for the sector. It is premature for Horizon Utilities to offer a position on the 100% fixed charge until the full implications of such have been articulated by the Board. Horizon Utilities would consider the implementation of a 100% fixed charge during the 2015-2019 rate plan term depending upon the full implications of such and the direction from the OEB.

9-SEC-86TC

[9-Staff-37 (a)] Please explain how the Applicant's answer is consistent with current Board policy.

Response:

Horizon Utilities has not provided detailed fixed asset continuity schedules on a gross basis, for the reasons explained in the response to Interrogatory 9-Staff-37. To reiterate, rate base is calculated based on average net book value and there is no impact to rate base of maintaining the gross amounts of assets and accumulated depreciation as compared to providing them on a MIFRS (net) basis. Horizon Utilities has maintained estimated CGAAP gross assets and accumulated depreciation total amounts for the period of 2011 to 2014 for the purpose of determining the variance between CGAAP and MIFRS for PP&E, accounted for in Variance Account 1575 - IFRS-CGAAP Transitional PP&E Amounts. Horizon Utilities offers that this is consistent with current Board policy.

1-SEC-87TC

SEC requests that the Applicant prepare a list, similar to the provincial government Sunshine List (applicable to the OEB, IESO, OPA, Hydro One and OPG) listing by name all employees who were paid over $100,000 in 2013, and the amount they were paid. We understand that the practice with the provincial government list is to use the T4 amount for each employee.

Response:

Horizon Utilities identifies that this is a request for new evidence rather than a request for clarification of the existing Application or interrogatory evidence and, as such, is outside the scope of the Technical Conference.

Additionally, this matter is the subject of submissions on confidentiality for resolution by the Board.

Horizon Utilities will be refusing to provide such information in this Technical Conference and otherwise unless compelled to do so by the Board. The basis for such refusal is articulated in Horizon Utilities' submission on confidentiality to the Board dated August 15, 2014.

Responses to Sustainable Infrastructure Alliance of Ontario Technical Questions

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4-SIA-34TC

In response to Interrogatory 4-SIA-31, Horizon confirmed that it “has not used the Service Revenue Requirement to calculate LEAP amounts” but used the “distribution revenue requirement” following guidance provided in section 2.7.3.6 of Chapter 2 of the Filing Requirements.

However, section 2.7.3.6 of the Filing Requirements states:

“The LEAP amount must be calculated based on total distribution revenues… …For greater clarity, Board-approved total distribution revenue means a distributor’s forecasted *service revenue requirement* as approved by the Board.” (*emphasis added*)

Given this clarification in the Filing Requirements, please confirm whether it remains Horizon’s position that the distribution revenue requirement should be used for the calculation of LEAP?

Response:

Horizon Utilities prepared the prefiled evidence and interrogatory responses according the Board’s statement that “the Board has determined that the greater of 0.12% of a distributor’s Board-approved distribution revenue requirement, or $2,000, is a reasonable commitment by all distributors to emergency financial assistance” per section 2.7.3.6 of the Chapter 2 Filing Requirements. Given the clarification noted in this question, Horizon Utilities has provided a revised calculation of the LEAP amounts for 2015 – 2019. Horizon Utilities has identified the variance between the two approaches; an average difference of approximately $6700 per year.

Table 1: LEAP Amounts per 4-SIA-34TC

	2015	2016	2017	2018	2019
Distribution Revenue Requirement	$ 112,956,026	$ 118,628,501	$ 121,743,444	$ 123,920,317	$ 127,881,899
Service Revenue Requirement	$ 118,433,942	$ 124,145,010	$ 127,299,380	$ 129,586,516	$ 133,635,798
LEAP As filed (0.12% of Distribution Revenue Requirement)	$ 135,547	$ 142,354	$ 146,092	$ 148,704	$ 153,458
LEAP (0.12% of Service Revenue Requirement)	$ 142,121	$ 148,974	$ 152,759	$ 155,504	$ 160,363
Variance	$ 6,573	$ 6,620	$ 6,667	$ 6,799	$ 6,905

8-SIA-35TC

In response to Interrogatory 8-SIA-33 part b), Horizon listed a number of payment options that it accepts from its customers on an ongoing basis. However, the interrogatory asked specifically about payment options during the situation identified in sub part a), namely at the time of imminent disconnection, as outlined in section 4.2.5b of the Distribution System Code, which states that:

> ***Where a distributor attends at a residential customer's property to execute a disconnection, whether during or after the distributor's regular business hours, the distributor shall ensure it has the facilities or staff available at that time to permit the customer to pay all amounts that are then overdue for payment by credit card issued by a financial institution. <u>The distributor may, in its discretion, also accept other forms of payment at the time of disconnection</u>. (<u>emphasis added</u>)***

For additional clarity, specifically in the situation noted above, does Horizon "in its discretion" accept any alternative forms of payment other than by credit card?

Response:

Horizon Utilities accepts alternative forms of payment other than by credit card when it attends a residential customer's property to execute a disconnection. The alternative forms of payment are: cash; certified cheque; money order; or verification of payment made by an electronic method such as on-line or tele-banking service.

Responses to Board Staff Technical Questions

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1-Staff-48TC

Reference: 1-Staff-10 – Performance Indicators and Measurement

In response to 1-Staff-10 (c), Horizon states that it has not developed reliability targets for 2015-2019 as data for 2015 is not available. Please clarify how service reliability indicators are used for planning purposes?

Response:

Horizon Utilities utilizes service reliability indicators to assist in the: identification; creation; and prioritization of the Capital Investment Programs. Asset Health, as quantified in the Asset Condition Assessment ("ACA"), identifies the magnitude of the future risk of failure; service reliability measures the historical failure. Combining the future risk of failure with the historical failure allows Horizon Utilities to identify the operating areas requiring investment and the appropriate Capital Investment Program for the area.

1-Staff-49TC

Reference: 1-Staff-11 – Level of Service Targets

In the reference, part a. Horizon quantified the potential impact for SAIDI for the projects at Table 1, but says that it has not calculated the price/improvement trade-off.

1. Please state the units for Table 1.

2. Since the cost of a project is forecasted, as is the expected impact to SAIDI, is it not reasonable to measure incremental benefits against the investment in question?

The original interrogatory 1-Staff-11(b) should have read:

In order to identify planned spending by driver, please tabulate all areas of capital and OM&A growth starting with the driver/need (e.g. poor reliability, worker safety, etc…) for the investment. Please indicate the anticipated directional or absolute result and expected timing of results.

Please use the suggested format below as guidance:

Driver	Expenditure	Activities	Results & Timing	Corresponding Projects/ Programs in Appendix A
e.g. Poor reliability	Capital Expenditure Operational Expenditure	Increase maintenance Perform system modifications and additions Install real-time monitoring assets	Improved reliability by month/year X Improvements in customer satisfaction	

3. Please complete 1-Staff11-(b) as suggested.

Response:

1. The units of measure for the values in Table 1 of Horizon Utilities' response to the Interrogatory 1-Staff-11 is hours.

2. Horizon Utilities response to Interrogatory 1-Staff-11 identified that a price/improvement calculation is not performed for each capital investment. Horizon Utilities believes that the response to Interrogatory 1-Staff-11 a) answered the question. Horizon Utilities has no further evidence to provide.

3. Horizon Utilities response to Interrogatory 1-Staff 11 b) provided the information that was requested, as understood by Horizon Utilities. Horizon Utilities did not include the table as suggested in the response as the information requested in the table did not align with Horizon Utilities' understanding of the information being requested in the table.

   In 1-Staff 49TC, part 3, Board Staff have restated the question to better align with the table but Horizon Utilities cannot provide a response to this amended request. Horizon Utilities cannot articulate the results and timing of the results as requested. Horizon Utilities would like to refer to its response to Interrogatory 1-Staff-21. The response to this interrogatory identifies: Horizon Utilities' capital and operating expenses; benefits of the project; project economics; rate impact; and pacing considerations.

1-Staff-50TC

Reference: 1-Staff-12 Planning Processes

At -1Staff-12(f), for project GP-1, Horizon indicates that it is using a 3-year cycle which allows a stable annual expenditure over the DSP term. Similar reasoning is used for GP-12 and GP-13, Vehicle Replacement and Tools, Shop and Garage Equipment respectively.

1. With respect to non-distribution assets, please clarify what is meant at 1-Staff-12(b) (ii) by "formulaic approach"?

2. Is there a basis other than "annual stable expenditure" for the cycles for projects GP-1, GP-12, and GP-13? For example, how did Horizon select a 3-year cycle for computer replacements? Does this schedule coincide with vendor support for instance, or industry best practices?

3. Respecting GP-4, when was the last enterprise phone system upgrade? What is the planned lifecycle replacement of Horizon's phone system?

4. Respecting GP-6, were the deferred infrastructure investments approved in EB-2010-0131? What was the amount that was deferred from 2008 until now? Were there any compounding effect in deferring the investments in buildings and infrastructure?

5. Without going into detail (as material was filed in confidence), can you restate what the security concerns are?

6. In response to 1-Staff-12(g), Horizon states that a varying load growth environment does not change Horizon's investment profile. Please indicate what projects were driven by load growth?

Response:

1. Horizon Utilities' definition of the term "formulaic approach" in this context is a process resulting in a quantitative score resulting from the relative scoring and weighting of a pre-defined set of inputs where the inputs and scoring criteria are used across all investments under consideration.

2. The replacement cycles for assets identified in the following projects are based on the following:

a) GP-1 Computer Replacements: As referenced in Horizon Utilities' response to Interrogatory Board Staff-21, a three-year PC refresh cycle reduces the total cost of ownership by reducing the number of models of PCs supported, which results in the reduction of the IST service desk effort required to deploy, secure, and manage new systems and applications. The reduction in the number of supported models has allowed Horizon Utilities to introduce mobile computing for remote field workers and to increase the number of supported PCs by over 100 devices since 2011, without an increase in IST service desk support staff. Reference: Exhibit 2, Tab 6, Appendix 2-4, Appendix A, pages 36-37

b) GP-12 – Vehicle Replacements - Horizon Utilities manages the fleet on an on-going basis by regular inspection and maintenance practices and uses both replacement and refurbishment strategies to allow planning on replacements to be done over a longer term which allows for a stable annual expenditure.

c) GP-13 – Tools and Equipment - is based on the condition of the asset. This project included expenditures pertaining to the purchase and replacement of tools and equipment, which are either worn; beyond repair; or the continued use of such creates health and safety risk.

3. Horizon Utilities' last enterprise phone system upgrade was in 2010. The planned lifecycle replacement for the enterprise phone system is every 5 years.

4. Project GP- 4 (John Street Renovations) was forecast in the 2011 CoS Application (EB-2010-0131), but due to capital reductions from the decision, these costs were deferred. Refer to Horizon Utilities' response to Interrogatory 1-Staff-12(f); the amount deferred from 2011 was $875K. No material investments in facilities were completed in the years 2008-2011, and this work was deferred until 2012. Since 2008, $4.2MM (including the $875K) was deferred. The compounding effects of these deferrals has been increased maintenance and repair costs, and increased capital replacement costs.

5. Horizon Utilities cannot restate the security concerns due to the confidential nature and risk to Horizon Utilities if this information is on the public record. The confidentiality related to this has been accepted by the OEB in PO#1.

6. The following system service projects are primarily driven by load growth:
    a. SS-3 Waterdown 3rd Feeder
    b. SS-5 Duct Structure – Elgin TS to King St
    c. SS-7 St. Paul Street Conductor Upgrade
    d. SS-9 Mohawk/Nebo TS Upgrade.

To clarify, Horizon Utilities' statement in response to Interrogatory 1-Staff-12 (g) with respect to a varying load growth environment was referring to investments in system renewal.

1-Staff-51TC

Reference: 1-Staff-13 – Planning

Are the amounts in response to 1Staff13(c) net benefits? If not, what are the net benefits of these projects?

Response:

- The value of $22,500,000 identified as the avoided capital cost resulting from converting the 4kV and 8kV distribution system to a higher voltage is a net benefit.

- The reduced capital expenditure of $450,000 resulting from migrating Horizon Utilities' ERP is an avoided capital cost that contributes to an annual net reduction in operating costs of $172,000 as identified on page 68 of Exhibit 2, Tab 6, Schedule 1 of the Application.

- The operational cost savings of $335,000 from 2015 to 2019 resulting from decommissioning the nine substations is a net benefit.

1-Staff-52TC

Reference: 1-Staff-14 – Benchmarking

At the reference, Horizon indicates that it benchmarked fleet replacement criteria against other LDCs in 2014 to determine whether its replacement guidelines were aligned with industry best practices. Please reconcile this statement with the one at 1-Staff-12(f), related to GP-12, Vehicle Replacement which mentions as a basis for replacement a stable annual expenditure over the DSP term.

Response:

The two statements are not meant to be reconciled as they refer to two different things. The replacement criteria outline how each vehicle is evaluated for replacement. Horizon Utilities manages the fleet on an on-going basis through inspection and maintenance programs, and utilizes both replacement and refurbishment strategies which enables Horizon Utilities to plan replacements over the longer term. This allows for a stable annual expenditure.

1-Staff-53TC

Reference: 1-Staff-15 – Monetizing Benefits

Are the monetized benefits described at the reference net benefits? If not what are the net benefits for these initiatives?

Response:

The monetized benefits identified in Horizon Utilities' response to Interrogatory 1-Staff-15 are net benefits.

1-Staff-54TC

Reference: 1-Staff-18 – Asset Condition Assessment

Response 1-Staff-18(a) states that the DSP contains an economic evaluation component. Please point to which economic evaluation you are referring to in the pre-filed evidence?

Response:

The economic evaluation component referred to can be found in the justification of the 4kV and 8kV Renewal Program and the XLPE Renewal Program in Section 3.5.3 of the DSP filed as Appendix 2-4 of Exhibit 2 of the pre-filed evidence.

1-Staff-55TC

Reference 1-Staff-20 – Asset Management Overview

In reference, Horizon indicates that it is unable to provide a comparative analysis between capital and O&M, and that Chapter 5 of the Filing Requirements does not specify that this information is required.

Also, Horizon states that it does not track planned vs. unplanned O&M.

At section 5.3.3 of Chapter 5, with respect to asset lifecycle optimization, the Board states that "information provided should be sufficient to show the trade-off between spending on new capital (i.e. replacement) and life-extending refurbishment".

Please complete your responses to 1Staff20 (a) and (b) to establish planning trends.

Response:

Horizon Utilities did not indicate in its response to Interrogatory 1-Staff-20 that it is unable to provide a comparative analysis between capital and O&M. It indicated that it was unable to provide a comparative analysis between capital and OM&A by the system asset categories identified in Appendix 2-AB (System Access, System Renewal, System Service, General Plant) which was Board Staff's request in part a) of the Interrogatory 1-Staff-20. A requirement to provide an OM&A breakdown by system asset category is not specified in the Chapter 5 Filing Requirements and this information is not available as identified in the interrogatory response. Horizon Utilities does not currently maintain its records in the manner in which Board Staff is asking it to respond.

Horizon Utilities included all available information in the response to 1-Staff-20 including trends for Total Capital Expenditures versus System O&M and has no further information to add to the response.

Horizon Utilities has provided information to show the trade-off between spending on new capital and life-extending refurbishment in Section 5.3.3 of the DSP filed as Appendix 2-4 of Exhibit 2.

1-Staff-56TC

Reference: 1-Staff-21 – Justification of DS Plan

Horizon filed qualitative analysis for the benefits and project economics.

1. Please provide a definition of non-discretionary for Horizon projects.

2. Are there any figures of merit related to the projects economics in the pre-filed evidence?

3. Is there any numerical information on the consequences on not proceeding with a project? If so please point to the evidence.

4. With respect to the projects economics, if business cases are available for material projects, please submit copies.

5. Where benefits are quantifiable please complete the table with appropriate information.

6. Please confirm that the expenditure cycles at table 2 are aligned with industry best practices.

Response:

1) The definition of non-discretionary projects is as follows:
    a. Distribution Plant projects: a score of 3, 4 or 5 as identified in column 1 of Table 1 of the Horizon Utilities' interrogatory response to 1-Staff-12.
    b. General Plant projects: a score of "High" as identified in column 2 of Table 1 of the Horizon Utilities' interrogatory response to 1-Staff-12.
2) Horizon Utilities is unclear what is being requested in this question. Horizon Utilities has provided the information available pertaining to these investments and has no further information to add.
3) Numerical information on the consequences of not proceeding with the 4kV and 8kV Renewal Program for the St. Catharines, Dundas, Hamilton West, and Hamilton Downtown Operating Areas is provided starting on page 241 of the DSP provided as Appendix 2-4 of Exhibit 2. The numerical consequences provided refer to the potential customer impact (volume of customers impacted and duration of outage). Numerical information on the consequences of not proceeding at a project level for System Renewal and System Service have been provided in Table 3 in each of the Material Capital Project Templates provided in Appendix G to the DSP.

4) There are no more business cases available other than those that Horizon Utilities has provided in the Application.
5) Horizon Utilities does not have any further information to add to Tables 1 and 2.
6) Horizon Utilities confirms that expenditure cycles at Table 2 are aligned with leading practices.

2-Staff-57TC

Reference: 2-Staff-22 Stranded Meters

Horizon stated in its response that it included a return component in the amount for the stranded meters used in calculating the Stranded Meter Rate Rider ("SMRR"). In Guideline G-2011-0001 pages 22 and 23, the Board stated:

"It is expected that a distributor, as part of its application for the disposition of smart meter costs in a cost of service application, will propose (a) rate rider(s) to recover the NBV of the stranded meters.

The recovery period should generally be accelerated (i.e. shorter than the average remaining life of the stranded meters). As a general rule of thumb, the Board expects that the recovery of stranded meter costs should be achievable in a period no longer than four years. The distributor can propose a shorter recovery period, but should take into account rate impacts on its affected customers, and may make proposals to mitigate potential material and adverse impacts. A distributor should provide an explanation for a recovery period longer than four years since the stranded meters are no longer used and useful and the proposed recovery period should, ideally, not go beyond the distributor's next cost of service rate application."

Please calculate a SMIRR based on the Net Book Value of the stranded meters as of December 31, 2014 based on a four year recovery period.

Response:

Horizon Utilities provides a monthly rate rider by rate class if the NBV of $7,974,590 is recovered through a rate rider over a four year recovery period in Table 1 below. The rate riders in Table 1 below do not include a rate of return.

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. As such, Horizon Utilities reiterates that if recovery of stranded meters is through a rate rider, it expects the recovery to include a regulated rate of return. Otherwise, Horizon Utilities submits that the recovery of only the NBV of the stranded meters is punitive in that it does not provide Horizon Utilities with a fair return on the capital it has invested in conventional meters.

Table 1

Customer Class	# of Active Metered Customers (average 2015)	NBV of Stranded Meters	Monthly Charge
Residential	220,565	$6,141,165	$0.58
GS< 50kW	18,428	$1,561,125	$1.76
GS>50kW	2,198	$272,299	$2.58
Total	**241,190**	**$7,974,590**	

3-Staff-58TC Forecast

Reference: 3-Staff-24

In part d. Horizon provided a volumetric forecast based on Board staffs terms. In Exhibit 3 Tab 1 Schedule 2 Horizon provided two forecasts; Table 3-26 based on 10 year average degree days, and Table 3-27 based on 20 years average degree days. What period was used to establish the average degree days in the interrogatory response?

Response:

Horizon Utilities response to Interrogatory 3-Staff-24 d) used the 20 year average degree days, consistent with its methodology as presented in Exhibit 3, Tab 1, Schedule 2.

4-Staff-59TC Post Employment Benefits

Ref: 4-Staff-27

1. On page 2, Horizon updated Table 4-120. Is this now the evidence and replaces the pre-filed evidence?

2. On page 4, Horizon has provided an update on Table 2. Is this now the evidence and replaces the pre-filed evidence?

3. If the answer to 1. And 2. Is yes, please file updated evidence on blue sheets.

4. On pages 4 and 5, Horizon states that "Under IFRS, actuarial gains and losses resulting from changes in actuarial assumptions and experience adjustments (the effects of differences between the previous actuarial assumptions and what has actually occurred), are recorded in the financial statements 1 in the current year as Other Comprehensive Income ("OCI"). Horizon Utilities has not requested any recovery of the amounts charged to OCI on transition to IFRS in the Application as it is expected that future differences resulting from these actuarial gains and losses will also be recorded in this account."

i. What is the referenced account?

ii. Is Horizon using an approved variance account for OCI? If so please state the account.

iii. What impact does OCI have on this application?

iv. Are costs that appear in OCI in the financial statements included in this application? If so, please indicate where.

Response:

1. This table is an update to the table produced in Interrogatory 4-Staff-27 part a) by Board Staff and does not replace the pre-filed evidence. There have been no amendments made to Table 4-120.

2. This table is an update to the table produced in 4-Staff-27 part b) by Board Staff and does not replace the pre-filed evidence.

3. Please refer to the responses in (1) and (2) above.

4. (i) The referenced account is Other Comprehensive Income ("OCI").

   (ii) Horizon is not using an approved variance account for OCI.

(iii) The impact of OCI has not been included in this Application. This has a favourable impact to customer rates, as Horizon Utilities has a loss of approximately $2,600,000 in Accumulated OCI at December 31, 2013.

(iv) Please refer to Horizon Utilities' response in (iii) above.

6-Staff-60TC Deferred Taxes

Reference: 6.0-VECC-48 - Deferred Taxes - Page 9.

Horizon did not apply to recover deferred taxes in this application. Rather, Horizon has asked the Board to comment on the fair return standard in light of only being permitted to recover current taxes.

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

1. Does Horizon now think the issue is outside the scope of this application?

2. If so, should Horizon's request be withdrawn so that cross-examination and submissions can be avoided?

3. If not, how could the parties settle the issue?

Response:

1. Yes. As a practical matter, the resolution of this issue is outside the scope of this Application.
2. Horizon Utilities suggests that the request be withdrawn from the Application. Horizon Utilities' intent of including this discussion in the Application was to create awareness of the implications of the Board's current policy with respect to the inclusion of cash taxes only in the revenue requirement. Horizon Utilities requests that the Board undertake a separate generic proceeding to investigate the issue.

6-Staff-61 TC Deferred taxes

Ref: 6-Staff-30 - Deferred Taxes - Page 5, paragraph (c)

Horizon states that it made submission as a member of the Coalition of Large Distributors in the Cost of Capital proceeding, EB-2009-0084. The submission stressed the need for recognition of fair returns to attract new capital.

1. Does Horizon think that it will have difficulty attracting new capital because of differences between rate regulation and accounting?

2. Does Horizon explain what these differences are in its financial statements?

3. Does Horizon discuss the differences with lenders so that they understand the complexities?

4. Are lenders and rating agencies relatively sophisticated in understanding the differences between rate regulation and accounting in assessing business risks?

5. If the interest rate on new debt is higher because of the differences between accounting and regulation, will the ratepayers bear the cost?

Response:

1. It is difficult to conclude on this matter. The large differences will result in rising and material future income tax liabilities. Generally speaking, rating agencies have not been concerned with the present nature or magnitude of future taxes. However, these may attract more attention if they become a material component of utility balance sheets
2. Yes – but only at a very high level.
3. Yes.
4. Yes.
5. Yes. These differences are an outcome of regulation and rate making policy.

7-Staff-62TC Cost Allocation

Re: 7 - Staff-31 Direct Allocations

Board staff would like further clarification on the development of the costs for direct assignment.

1. Did Horizon use actual records from the installation date of the specific costs incurred for these customers? If not, what is the overall average costs, or average costs based on the year installed? Please explain.

2. How did Horizon account for any contributions in aid of construction that it received from the customers?

Response:

a) Horizon Utilities has allocated the actual NBV of the directly allocated assets to the LU (2) class.

b) Horizon Utilities did not directly allocate any contributions in the aid on construction as the directly allocated capital work relates to the replacement of an existing facility – not a new connection. In this case there is no contribution in aid of construction.

9-Staff- 63TC – Account 1592TC

Re; 9-Staff-39

Horizon is proposing to dispose of $19,885 in Account 1592. According to Horizon, this balance comprises the cumulative principal difference arising from the differences in the actual tax rate (26.5%) and approved tax rate (26.05%) used for the tax savings rate rider approved in Horizon's 2012 IRM application (EB-2011-0172).

The APH states, for Account 1592 PILs and Tax Variances for 2006 and Subsequent Years, the account shall be used for:

1. any differences that result from a legislative or regulatory change to the tax rates or rules assumed in the 2006 OEB Tax Model.

2. any differences that result from a change in, or a disclosure of, a new assessing or administrative policy that is published in the public tax administration or interpretation bulletins by relevant federal or provincial tax authorities.

3. any differences in 2006 PILs that result in changes in a distributor's "opening" 2006 balances for tax accounts due to changes in debits and credits to those accounts arising from a tax re-assessment:

i. received by the distributor after its 2006 rate application is filed, and before May 1, 2007; or

ii. relating to any tax year ending prior to May 1, 2006.

In light of the above:

4. Please comment on Horizon's proposal for recovery of account 1592 which was disposed of on final basis in its 2012 IRM proceeding.

5. Please confirm that the tax rate change was not a change due to changes in the levels of tax rates set by authorities, but rather due to the results from estimating taxes and the resulting actual calculated taxes.

Response:

1. [Numbered as 4 in the question above] The tax sharing amount was calculated using the Board's tax sharing model which included an incorrect tax rate of 26.05% as provided by the Board. Subsequent to Horizon Utilities' 2012 IRM proceeding, Horizon Utilities recalculated the tax sharing amount using the correct tax rate of 26.5%. This resulted in an amount to be recovered from customers of $19,885.
2. [Numbered as 5 in the question above] The tax rate change was due to an error in the tax rate provided in the Board's tax sharing model. It was not a change due to changes in the levels of tax rates set by authorities.

9-Staff-64TC – Account 1518 and 1548

Re: 9-Staff-44

In response to this IR, Horizon stated: "However, a significant portion of these costs are fixed, such as the fixed portion of the software license and maintenance fee and the costs associated with billing staff and regulatory staff."

According to the APH Article 490:

"It should be noted that the RCVA relate only to the incremental costs of providing the retail services listed below. Note that "Incremental cost" is defined as the change in total expenses under a new condition (i.e. requirement to provide a new service) in comparison to some given known condition (i.e. costs incurred prior to the requirement to provide the new service)."

Board staff notes that fixed costs, by definition, are not incremental. Therefore, it appears that Horizon is not calculating balances in the RCVA accounts in accordance with the APH.

1. Please explain the horizon's view of including fixed costs as incremental for the purposes of allocating fixed costs to the RCVAs.

2. Please provide substantiation that the assets acquired were solely for the purposes of retail services.

Response:

1. In its response to Interrogatory 9-Staff-44, Horizon Utilities' reference to fixed costs meant costs which are unaffected by:
    a. changes in the activity level of retailer transactions; and
    b. changes in the number of customers with retailers.

These fixed costs can be incremental. As an example, the software license and maintenance fees for the retailer billing system have a fixed component which does not vary with the number of retailer transactions or the number of retail customers. These costs are still incremental in that they are incurred solely to provide retailer services. Similarly, the time incurred by regulatory, billing and IT staff does not vary with activity level. The same functions are performed irrespective of the number of retailer transactions or the number of customers with retailers. These costs are incremental in that they would not be incurred if Horizon Utilities was not providing retailer services. As such, Horizon Utilities believes it is calculating balances in the RCVA accounts in accordance with the APH.

2. No assets were acquired for the purposes of supplying retailer services. Horizon Utilities pays a software license and maintenance fee to a third party for retailer services. Horizon Utilities also incurs incremental employee expenses to administer retailer services.

Responses to Vulnerable Energy Consumers Coalition Technical Questions

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1.0 – VECC - 64TC

Reference: 1-Staff-15 / BOMA-8

a) For the e-mobile efficiencies shown (by reference in the interrogatory response) at E4/T3/S4/pg. 9Table 4-46 please provide the following:

i. Savings for the reduction of 2 FTEs

ii. Description of the "Future Costs" that being avoided and why they escalate up to 2014 and then remain at $400k

iii. Show how the productivity improvement/capacity savings are calculated in each of the years

iv. Show the derivation of the "realized operating expenditure reductions and why it escalates to $600k in 2014 and remains at that figure onward.

Please show all assumptions.

Response:

a) In the course of responding to Technical Questions regarding e-mobile productivity, Horizon Utilities identified that some components of Operating Expenditure Reductions and Productivity and Capacity Improvements were misclassified between e-mobile and the miscellaneous initiatives. The most significant reclassification is for "Web self-service – reduction in call volumes" as referenced in Exhibit 4, Tab 3, Schedule 4, Page 40 of 40. Web self-service should have been included in Productivity and Capacity Improvements under the miscellaneous category and not e-mobile.

With this reclassification, as of the end of the Custom IR period the productivity savings achieved by Horizon Utilities in 2019 are reduced by $34,700.

The reclassification in Customer Services does not impact Horizon Utilities' revenue requirement.

However, in the interest of providing greater clarity, a corrected BOMA-8_Attch_3_Customer Services is being provided as Attachment 1. Horizon Utilities is also providing corrected tables for Exhibit 4, Tab 3, Schedule 4, specifically Table 4-43, Table 4-44, Table 4-45, Table 4-46, and Table 4-48. These revised tables are provided in Attachments 2 through 6 respectively.

i.) The savings corresponding to the two FTE reductions from e-mobile operating reductions comprise: i) a Meter Technician beginning in 2011, valued at approximately $130,000 annually; and ii) one clerical FTE beginning in mid-2012 valued at approximately $35,000 annually. As a result of the reclassification identified above, an additional three clerical FTEs were reallocated to e-mobile operating expenditure reductions as follows: i) one FTE was reallocated from Operating Expenditure Reductions, Miscellaneous valued at $65,000 annually; and ii) two FTEs were reallocated from e-mobile productivity and capacity improvements, both beginning in 2014, valued at $65,000 and $75,000 annually. The two new FTE reductions are as a result of the increased capacity achievement in the department which has now translated to permanent headcount reductions.

ii) E-mobile future cost avoidance expenditures are comprised of 3 main components: i) the cost avoidance related to the hiring of additional supervision to perform crew visits, safety inspections, and enhanced communications valued at $28,000 annually; ii) the elimination of the hiring of a Connections Clerk to support new customer connections valued at $85,000 annually; and iii) the elimination of the need to operate one cargo van valued at $10,000 annually.

Please refer to the corrected Table 4-46 in Attachment 5.

The e-mobile program is fully implemented as of the end of 2014. Future cost avoidance is being sustained in 2015 and beyond.

iii) Please refer to the corrected BOMA-8_Attch_3_Customer Services for the initiative details in Attachment 1.

E-Mobile Productivity and Capacity Improvements

- includes the redeployment of two Meter Technicians from performing field related activities to supporting new customer connections, one in 2012 and one in 2014, as referenced in Exhibit 4, Tab 3, Schedule 4, Page 8 or 40. The Meter Technicians have been valued at approximately $130,000 annually; and,

- the redeployment of one Connections Clerk planned for 2015 due to capacity built to date and, as previously discussed, the future cost avoidance of a Connections Clerk to support new customer connections. The Connections Clerks are each valued at approximately $85,000 annually.

Automation and Streamlined Processes

- Includes a number of processes which were streamlined through automation including:
  - Collections activities such as: notice management; delivery of customer disconnection advisement calls; the elimination of filing; auto-returning of collection service orders; the elimination of agents calling into the office to determine the status of customer payments; the auto-deletion of customer disconnection orders where payment was received and the field visit was no longer required; the auto-return of service orders where an agent action is required due to vacant location; reporting, which decreased manual reconciliation efforts; and the automation of collections orders. The increased capacity from these initiates was measured to be approximately 70 hours per week, valued at burdened labour rates corresponding to the specific task.
  - The automation of meter change data being populated into the Customer Information System and Advanced Metering Infrastructure systems, which increased capacity by 15 hours per week, calculated at burdened labour rates.

Miscellaneous

- "Web self-service – reduction in call volumes" is the reduction in call volumes of 170,000 annually as of 2014 which has been estimated by the number of calls avoided to the Call Centre based upon the number of self-service activities performed directly by customers, and the assumption that a percentage of logins to myAccount result in the elimination of customer calling the Call Centre. It is assumed that customer calls have been avoided since the enhancement of the

Horizon Utilities website and self-service functions since May 2012. The value of a customer call has been estimated to be approximately $4.00 per call.

- “Reduction in dedicated admin time – Call Centre” is the reduction in elimination of 15 minutes dedicated daily time for Call Centre agents to perform administration tasks such as time-entry, e-mail management, check voice-mails, etc. The agents are now expected to perform these tasks during any gaps between customer calls. The additional capacity to the workgroup has been calculated at 15 minutes per day per agent at the burdened labour rate per agent.
- The 14-hour banked time program is a program that allowed Customer Service staff to work through their lunches to “bank” up to 14 hours of time per calendar year that could be used in lieu of vacation time, pending supervisor approval. This program was discontinued to build required capacity in the department. The capacity was calculated at 14 hours per employee at burdened labour rates.
- Other – automation initiatives includes a number of small processes that have been automated including the transfer sheets related to retailer accounts, the clerical task of completing a customer move-in or move-out that was initiated on the website, the automation of microFIT payments, and streamlining of collection agency processes. The tasks have built additional capacity in the department of approximately 15 hours per week valued at burdened labour rates.

iv) Please refer to the corrected BOMA-8_Attch_3_Customer Services in Attachment 1. The e-mobile program is fully implemented as of the end of 2014. Operating reductions are being sustained in 2015 and beyond.

1.0-VECC-64TC Attachment 1: BOMA-8_Attch_3_Customer Services_Corrected

Initiative	2011	2012	2013	2014	2015	2016	2017	2018	2019
Operating Expenditure Reductions									
E-Mobile									
1 FTE Reduction Meter Technician	19,718	118,310	121,860	132,000	132,000	132,000	132,000	132,000	132,000
1 FTE Clerical Role	-	30,940	33,672	34,200	34,200	34,200	34,200	34,200	34,200
1 FTE Reduction: General Clerk St. Catharines	-	-	25,932	65,000	65,000	65,000	65,000	65,000	65,000
1 FTE Reduction: General Clerk Hamilton	-	-	-	65,000	65,000	65,000	65,000	65,000	65,000
1 FTE Reduction: Collections Clerk	-	-	-	50,000	75,000	75,000	75,000	75,000	75,000
Reduction in paper and printing	5,586	29,521	30,142	35,000	35,000	35,000	35,000	35,000	35,000
Other (Reduction in Fleet requirements)	-	5,256	5,256	5,300	5,500	5,500	5,500	5,500	5,500
Sub-total	**25,304**	**184,027**	**216,862**	**386,500**	**411,700**	**411,700**	**411,700**	**411,700**	**411,700**
Outsourcing									
MV90 Operator	-	-	60,391	70,000	60,000	60,000	60,000	60,000	60,000
Call Centre Overflow	-	-	-	-	-	10,000	20,000	30,000	40,000
Sub-total	**-**	**-**	**60,391**	**70,000**	**60,000**	**70,000**	**80,000**	**90,000**	**100,000**
Miscellaneous									
Meter Reading Expenditure Reduction	-	93,236	144,928	150,000	150,000	150,000	150,000	150,000	150,000
E-Billing for Multi-account Customer	-	3,216	10,618	15,000	15,000	17,000	19,000	19,000	19,000
Overtime Reduction	-	55,863	32,895	35,000	25,000	20,000	20,000	20,000	20,000
Payment pickups from Drop-off Locations	-	-	4,080	4,000	4,000	4,000	4,000	4,000	4,000
Courier Service Elimination	-	-	5,355	9,000	9,000	9,000	9,000	9,000	9,000
Increase in e-billing services	-	-	5,970	23,500	57,000	80,000	98,000	118,000	138,000
Other	-	24,563	12,000	-	-	-	-	-	-
Sub-total	**-**	**176,878**	**215,846**	**236,500**	**260,000**	**280,000**	**300,000**	**320,000**	**340,000**
Total CS Operating Expenditure Reductions	**$ 25,304**	**$360,905**	**$ 493,099**	**$ 693,000**	**$ 731,700**	**$ 761,700**	**$ 791,700**	**$ 821,700**	**$ 851,700**
Productivity and Capacity Improvements									
E-Mobile									
2 FTE Redeployment Connections Clerks	31,200	81,900	84,360	85,600	170,000	175,600	175,600	175,600	175,600
2 FTE Redeployment Meter Technicians	-	9,859	121,860	264,120	265,000	265,000	265,000	265,000	265,000
Automation / Streamlined processes	20,618	162,686	213,221	229,167	265,000	265,000	265,000	265,000	265,000
Sub-total	**51,818**	**254,445**	**419,441**	**578,887**	**700,000**	**705,600**	**705,600**	**705,600**	**705,600**
Miscellaneous									
Web self-service - reduction in call volumes	-	-	400,000	680,000	680,000	680,000	680,000	680,000	680,000
Reduction in dedicated admin time - Call Centre	-	62,424	62,664	62,988	60,000	60,000	60,000	60,000	60,000
Elimination of 14-hour banked time program	-	33,603	34,608	33,168	33,000	33,000	33,000	33,000	33,000
Other (Automation initiatives)	-	23,575	38,983	35,759	40,000	60,000	80,000	90,000	100,000
Sub-total	-	119,602	536,255	811,915	813,000	833,000	853,000	863,000	873,000
Total CS Productivity and Capacity Improvements	**$ 51,818**	**$374,047**	**$ 955,696**	**$1,390,802**	**$1,513,000**	**$1,538,600**	**$1,558,600**	**$1,568,600**	**$1,578,600**

1.0-VECC-64TC Attachment 2: Table 4-43_Corrected

Initiatve	Type	2011 Actual	2012 Actual	2013 Actual	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Construction & Maintenance	Operating Expenditure Reductions	$ -	$ 100,000	$ 100,000	$ 300,000	$ 400,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000
	Productivity Improvements / Capacity	$ -	$ 600,000	$ 1,720,000	$ 1,720,000	$ 1,720,000	$ 1,720,000	$ 1,720,000	$ 1,720,000	$ 1,720,000
Information Systems & Technology	Operating Expenditure Reductions	$ -	$ -	$ 60,000	$ 200,000	$ 220,000	$ 220,000	$ 220,000	$ 220,000	$ 220,000
	Productivity Improvements / Capacity	$ -	$ -	$ -	$ 140,000	$ 1,020,000	$ 1,020,000	$ 1,020,000	$ 1,050,000	$ 1,150,000
Customer Services	Operating Expenditure Reductions	$ 25,304	$ 360,905	$ 493,099	$ 693,000	$ 731,700	$ 761,700	$ 791,700	$ 821,700	$ 851,700
	Productivity Improvements / Capacity	$ 51,818	$ 374,047	$ 955,696	$ 1,390,802	$ 1,513,000	$ 1,538,600	$ 1,558,600	$ 1,568,600	$ 1,578,600
Supply Chain Management	Operating Expenditure Reductions	$ -	$ 20,000	$ 40,000	$ 80,000	$ 100,000	$ 100,000	$ 110,000	$ 120,000	$ 110,000
	Productivity Improvements / Capacity	$ -	$ 20,000	$ 50,000	$ 90,000	$ 90,000	$ 100,000	$ 100,000	$ 120,000	$ 140,000
Finance	Operating Expenditure Reductions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Productivity Improvements / Capacity	$ -	$ -	$ 50,000	$ 240,000	$ 340,000	$ 340,000	$ 340,000	$ 340,000	$ 340,000
Total		**$ 77,122**	**$ 1,474,952**	**$ 3,468,795**	**$ 4,853,802**	**$ 6,134,700**	**$ 6,300,300**	**$ 6,360,300**	**$ 6,460,300**	**$ 6,610,300**
OM&A per Application		$50,790,410	$51,478,365	$54,522,505	$60,387,369	$62,632,679	$64,394,131	$66,255,827	$67,708,658	$69,140,489
Productivity as a % of Total OM&A		*0.2%*	*2.9%*	*6.4%*	*8.0%*	*9.8%*	*9.8%*	*9.6%*	*9.5%*	*9.6%*

1.0-VECC-64TC Attachment 3: Table 4-44_Corrected

	2011 Actual - Restated MIFRS	2012 Actual MIFRS	2013 Actual MIFRS	2014 Bridge Year MIFRS	2015 Test Year MIFRS
OM&A per Application	$ 50,790,410	$ 51,478,365	$ 54,516,505	$ 60,387,369	$ 62,632,679
YOY growth		*1.4%*	*5.9%*	*10.8%*	*3.7%*
Add: Productivity Savings	$ 77,122	$ 1,474,952	$ 3,468,795	$ 4,853,802	$ 6,134,700
OM&A without Productivity	$ 50,867,532	$ 52,953,317	$ 57,985,300	$ 65,241,171	$ 68,767,379
YOY growth		*4.1%*	*9.5%*	*12.5%*	*5.4%*

	2016 Test Year MIFRS	2017 Test Year MIFRS	2018 Test Year MIFRS	2019 Test Year MIFRS	CAGR 2011 to 2019	CAGR 2011 to 2015	CAGR 2015 to 2019
OM&A per Application	$ 64,394,131	$ 66,255,827	$ 67,708,658	$ 69,140,489			
YOY growth	*2.8%*	*2.9%*	*2.2%*	*2.1%*	*3.9%*	*5.4%*	*2.5%*
Add: Productivity Savings	$ 6,300,300	$ 6,360,300	$ 6,460,300	$ 6,610,300			
OM&A without Productivity	$ 70,694,431	$ 72,616,127	$ 74,168,958	$ 75,750,789			
YOY growth	*2.8%*	*2.7%*	*2.1%*	*2.1%*	*5.1%*	*7.8%*	*2.4%*

1.0-VECC-64TC Attachment 4: Table 4-45_Corrected

Initiatve	Type	2011 Actual	2012 Actual	2013 Actual	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
E-mobile	Operating Expenditure Reductions	$ 25,304	$ 184,027	$ 216,862	$ 386,500	$ 411,700	$ 411,700	$ 411,700	$ 411,700	$ 411,700
	Productivity Improvements / Capacity	$ 51,818	$ 254,445	$ 419,441	$ 578,887	$ 700,000	$ 705,600	$ 705,600	$ 705,600	$ 705,600
Customer Service - Outsourcing	Operating Expenditure Reductions	$ -	$ -	$ 60,391	$ 70,000	$ 60,000	$ 70,000	$ 80,000	$ 90,000	$ 100,000
	Productivity Improvements / Capacity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service - Miscellaneous	Operating Expenditure Reductions	$ -	$ 176,878	$ 215,846	$ 236,500	$ 260,000	$ 280,000	$ 300,000	$ 320,000	$ 340,000
	Productivity Improvements / Capacity	$ -	$ 119,602	$ 536,255	$ 811,915	$ 813,000	$ 833,000	$ 853,000	$ 863,000	$ 873,000
Total		**$ 77,122**	**$ 734,952**	**$ 1,448,795**	**$ 2,083,802**	**$ 2,244,700**	**$ 2,300,300**	**$ 2,350,300**	**$ 2,390,300**	**$ 2,430,300**

1.0-VECC-64TC Attachment 5: Table 4-46_Corrected

Initiatve	2011 Actual	2012 Actual	2013 Actual	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Realized Operating Expenditure Reductions	$ 25,304	$ 184,027	$ 216,862	$ 386,500	$ 411,700	$ 411,700	$ 411,700	$ 411,700	$ 411,700
Productivity Improvements / Capacity	$ 26,818	$ 131,176	$ 293,313	$ 450,997	$ 570,000	$ 575,600	$ 575,600	$ 575,600	$ 575,600
Future Cost Avoidance	$ 25,000	$ 123,269	$ 126,128	$ 127,890	$ 130,000	$ 130,000	$ 130,000	$ 130,000	$ 130,000
Total	**$ 77,122**	**$ 438,472**	**$ 636,303**	**$ 965,387**	**$ 1,111,700**	**$ 1,117,300**	**$ 1,117,300**	**$ 1,117,300**	**$ 1,117,300**

1.0-VECC-64TC Attachment 6: Table 4-48_Corrected

	2011 Actual	2012 Actual	2013 Actual	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Realized Operating Expense Savings	$ -	$ 176,878	$ 215,846	$ 236,500	$ 260,000	$ 280,000	$ 300,000	$ 320,000	$ 340,000
Productivity Improvements / Capacity	$ -	$ 119,602	$ 536,255	$ 811,915	$ 813,000	$ 833,000	$ 853,000	$ 863,000	$ 873,000
Total	**$ -**	**$ 296,480**	**$ 752,101**	**$ 1,048,415**	**$ 1,073,000**	**$ 1,113,000**	**$ 1,153,000**	**$ 1,183,000**	**$ 1,213,000**

2.0 – VECC - 65TC

Reference: 2-AMPCO-9

a) Chart 3 indicates that the linear trend is calculated with "2006-2013 Actual and 2013 Forecast" (emphasis added). Please confirm that the chart uses 2013 forecast and not 2014 forecast as shown in the diagram.

b) Please recalculate and show the trend shown in Chart 3 through 5 starting in 2007 and with the elimination of the 2014 forecast SAIFI/SAIDI&CAIDI service quality indicators.

Response:

a. Horizon Utilities confirms that the linear trend illustrated in Chart 3 is based on actual data for 2006 to 2013 and forecast data for 2014.

b. Charts 3 through 5 have been recalculated and provided below to show only 2007 to 2013 data.

Chart 3

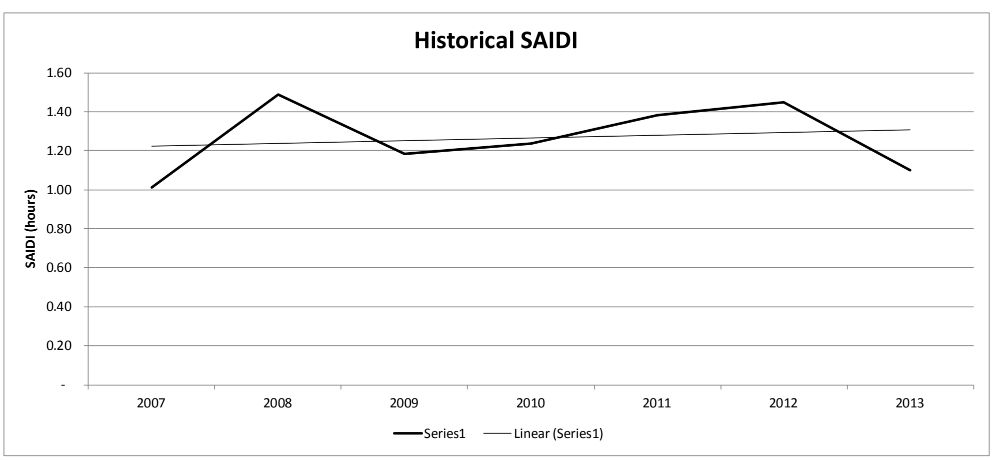


Chart 4

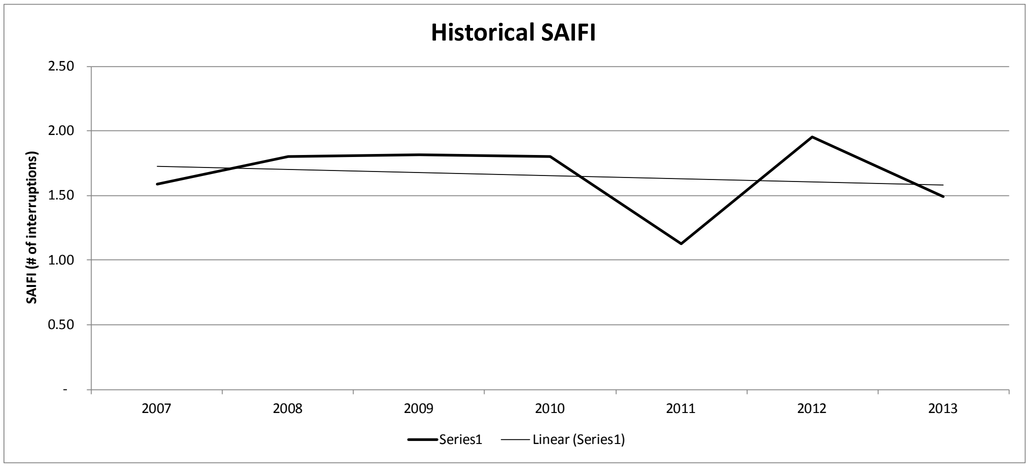
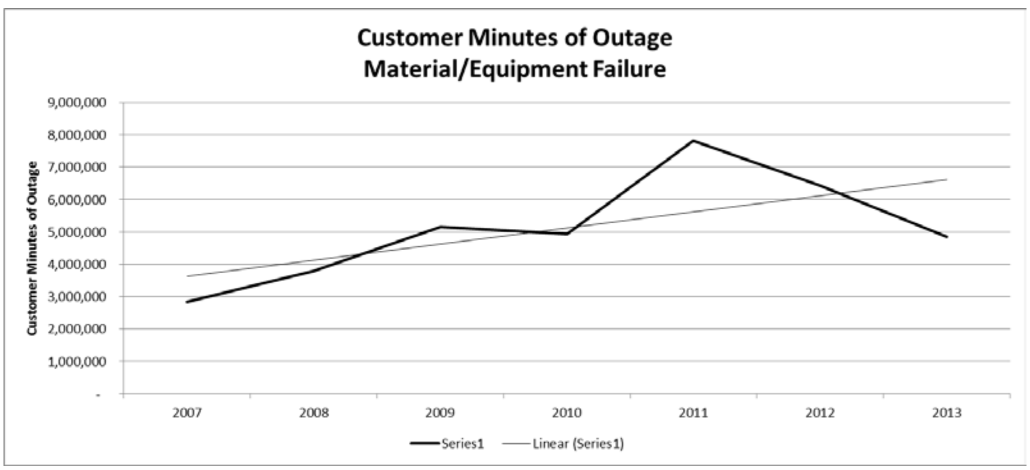


Chart 5



2.0 – VECC - 66TC

Reference: 2-BOMA-4

a) 3 Versions of the KPMG Assurance Review were produced. Two revisions were made after the original report in order to respond to Horizon feedback. Please provide a list of the (substantive) feedback or changes that were made due to Horizon`s feedback.

Response:

There was no substantive feedback or changes that were made due to Horizon Utilities' feedback.

2.0 – VECC - 67TC

Reference: 1-Staff-3 /1.0-VECC-1 & 4

Horizon's proposal represents a "regulatory compact" in which, if approved, the regulator would allow Horizon to adjust rates on a pre-determined basis and based (in part) on the reviewed 5 year capital program. It is expected that that the forecast capital budgets/in-service rate base will not be the same as actual experience in any given year due to (1) construction timing; (2) variances in labour and material costs; (3) modifications to project; and (4) project cancellation/replacements due to changes in priorities/need. While some of these variances may be small others could be substantial and materially impact the long-term capital plan being presented in this application.

a) For each of the four categories mentioned above please provide Horizon's view as to what would constitute a material deviation from the proposed plan.

b) For any material deviation in the 5 year capital plan how will Horizon engage the Board and intervenors to seek assurance that it remains within the approved regulatory compact?

Response:

a) If a materiality threshold is to be operative in the context of a 5-year Custom IR, as this application is, a possible threshold may be as calculated in Exhibit 1, Tab 6, Schedule 1. However, the Board's Custom IR setting option under the RRFE does not require that capital deviations for any reason and for any magnitude need to be addressed. As such, Horizon Utilities' Application does not have any such proposal.

b) Horizon Utilities has nothing further to add to what it has already provided in its responses to Interrogatories 1-Staff-3 and 1.0-VECC-1 and 4 as in the references noted in the question above.

2.0 – VECC – 68TC

Reference: 2.0-VECC-6

a) Please amend the Table provide in response to 2.0-VECC-6 to show the percentage of each customer class on monthly or bi-monthly billing.

Response:

a) Horizon Utilities has a mix of bi-monthly and monthly billing cycles. Please refer to the table below for breakdown of billing cycles by rate class as a percentage.

Rate Classification	Monthly%	Bi Monthly%
Residential	3.2%	96.8%
General Service < 50	82.8%	17.2%
General Service > 50	100.0%	0.0%
Large Users	100.0%	0.0%
Unmetered and Scattered	99.6%	0.4%
Sentinel	58.4%	41.6%
Streetlights	100.0%	0.0%

2.0 – VECC – 69TC

Reference: 2-Staff-22 / 2.0-VECC-7

a) Does Horizon believe its smart meter proposal to leave these assets in rate base is consistent with current Board policy?

b) Is it Horizon's position that it is entitled to a rate of return on the undepreciated value of conventional meters replaced by smart meters that are no longer used or useful?

Response:

a) Horizon Utilities believes that its proposal to leave stranded meters in rate base is consistent with current Board policy. Section 2.5.1.4, page 18 of the Chapter 2 Filing Requirements provides for the possibility of a different approach from that set out in Guideline G-2011-0001 as follows: "Distributors wishing to propose a different approach to that outlined above must provide a full explanation of the proposed approach and justifications for it, including why the described approach would not be applicable to their circumstances."

b) Yes it is Horizon Utilities position that it is entitled to a rate of return on the undepreciated value of stranded meters for the reasons identified in its response to Interrogatory 2-Staff-22 and 2.0-VECC-7.

3.0 –VECC -70TC

Reference: 3-Staff-24 d)

a) Please clarify whether the kWh values provided in the response are before or after the manual adjustment for CDM.

Response:

The kWh values provided in the response to 3-Staff-24 d) are kWhs after the manual adjustment for CDM.

3.0 –VECC -71TC

Reference: 3-Energy Probe-19

Preamble: According to the response to EP-19 (a), one of the reasons for the negative coefficient on the RPDI Trend variable is that is capturing the impact of improving energy efficiency including the impact of "past CDM" activity.

a) Please confirm that in developing the Residential forecast for 2015-2019 Horizon as continued to increase the value of the trend variable throughout this period.

b) Does increasing the trend variable and then also manually adjusting for future CDM programs result in a double counting of the impact of future CDM activity? If not, why not?

c) Please provide an alternative Residential load forecast for 2015-2019 (prior to any CDM adjustment) where the value for the trend variable is held constant at the December 2013 level throughout the projection period.

d) Please also provide alternative GS<50 and GS>50 load forecasts for 2015-2019 where the value for the GDP Trend variable is held constant at the December 2013 level throughout the projection period.

Response:

a) Horizon Utilities confirms that the trend continues through the forecast period, as we assume that the changing relationship between real personal disposable income and customer use continues through the forecast period.

b) No, the trend variable captures much more than past CDM activity. Customer usage has been trending down even before CDM was ramping up. The trend is capturing significant improvements in overall efficiency resulting from customers replacing old appliances and equipment with new appliances, new appliance and equipment energy efficiency, and improving housing and building efficiency standards. New lighting standards, for example, are expected to have a significant impact on residential customer usage. Horizon Utilities CDM adjustment to the load forecast is for incremental savings.

c) Horizon Utilities has provided an alternative Residential load forecast for 2015-2019 (prior to any CDM adjustments) where the value for the trend variable is held constant at the December 2013 level throughout the projection period below.

Table 1: Residential Load Forecast With Trend Variable Held Constant (2015-2019) Before CDM Adjustment

	As Filed Unadjusted for CDM (kWh)	Trend Held Constant Unadjusted for CDM (kWh)
2014 Bridge Year	1,633,183,207	1,637,780,899
2015 Test Year	1,630,604,915	1,644,280,267
2016 Test Year	1,632,113,317	1,655,070,876
2017 Test Year	1,627,702,719	1,660,316,444
2018 Test Year	1,627,604,338	1,670,285,072
2019 Test Year	1,626,379,723	1,679,369,074

d) Horizon Utilities has provided an alternative GS < 50 kW and GS > 50 kW load forecast for 2015-2019 (prior to any CDM adjustments) where the value for the GDP trend variable is held constant at the December 2013 level throughout the projection period below.

Table 2: GS < 50 kW Load Forecast With Trend Variable Held Constant (2015-2019) Before CDM Adjustment

	As Filed Unadjusted for CDM (kWh)	Trend Held Constant Unadjusted for CDM (kWh)
2014 Bridge Year	590,199,426	591,549,392
2015 Test Year	590,445,253	594,303,969
2016 Test Year	591,143,528	597,606,647
2017 Test Year	589,487,741	598,661,145
2018 Test Year	588,749,906	600,716,322
2019 Test Year	587,936,814	602,792,724

Table 3: GS > 50 kW Load Forecast With Trend Variable Held Constant (2015-2019) Before CDM Adjustment

	Unadjusted for CDM (kWh)	Adjusted for CDM (kWh)
2014 Bridge Year	1,865,094,324	1,867,143,310
2015 Test Year	1,872,385,651	1,878,326,286
2016 Test Year	1,882,436,649	1,892,416,845
2017 Test Year	1,886,034,069	1,900,218,102
2018 Test Year	1,892,041,498	1,910,558,143
2019 Test Year	1,897,968,467	1,920,966,795

3.0 –VECC -72TC

Reference: 3-Energy Probe-23 d)

a) Given that Revenues from Merchandising have been increasing annually from 2011 through to May 2014, why is it reasonable to base the 2014 budget values on the average over the past 30 months of January 2011 to June 2013)?

b) What would be the annualized value if based on the past thirty months ending May 2014?

Response:

a) The 2014 Budget was prepared in the second half of 2013 using the most up to date historical information that was available at the time, which would be the period up to June 2013. The 30 month period is a sufficient length to incorporate the overall increasing trend of revenue over the period.

b) The annualized value would be $253,592 if based on the past thirty months ending May 2014.

3.0 –VECC -73TC

Reference: 3-VECC-14

c) How did Horizon's billing system manage to record actual monthly sales for the Residential and GS<50 classes prior to the introduction of smart meters?

Response:

Horizon Utilities' underlying monthly sales data has a component of actual sales and unbilled sales and does not use the smart meter data for the Residential and GS < 50 kW classes.

3.0 –VECC -74TC

Reference: 3-VECC-17 c)

a) Please provide a response to the original interrogatory which asked for a schedule showing the persistence of the impact from CDM programs implemented in 2011-2014 (by year) for the test period years of 2015-2019.

Response:

Horizon Utilities does not have the data associated with the persistence information to provide the persistence of the impact from CDM programs implemented in 2011-2014 (by year) for 2015-2019. The OPA tracks the persistence of measures through its centralized reporting system.

3.0 –VECC -75TC

Reference: 3-VECC-17 a) & f)

a) Based on the response to VECC 17 a) does Table 3.5 in the original application need to be revised.

b) Similarly, do the OPA reported results for 2013 (per part (f)) alter Table 3.5 in the original application?

c) If yes for either parts (a) or (b), please provide a revised version for Table 3.5. If not, why not?

d) Does this revision affect any of the other Tables in the Application? If so, please indicate which ones and provide the necessary updates.

Response:

a) Yes, based on the response to VECC 17 a) Table 3-5 does require an update and has been provided in the response below.

b) Yes, based on the response to VECC 17 f) Table 3-5 does require an update and has been provided in the response below.

c) Horizon Utilities has provided a revised version of Table 3-5 below using the 2013 preliminary results received August 1, 2014 and has included the report as 3-VECC-75c_Attch 1_Draft Annual 2013 CDM Report.

1 **Revised Table 3-5: Chapter 2 Filing Requirements Appendix 2-I – Load Forecast CDM**
2 **Adjustment Work Form 2011 - 2014**

4 Year (2011-2014) kWh Target:					
281,420,000					
	2011	**2012**	**2013**	**2014**	**Total**
2011 CDM Programs	12.28%	12.20%	12.17%	12.05%	48.70%
2012 CDM Programs		6.19%	6.12%	6.06%	18.37%
2013 CDM Programs			9.38%	9.27%	18.65%
2014 CDM Programs				14.28%	14.28%
Total in Year	**12.28%**	**18.39%**	**27.67%**	**41.66%**	**100.00%**
		kWh			
2011 CDM Programs	34,555,703	34,342,396	34,235,743	33,915,783	137,049,625
2012 CDM Programs		17,418,442	17,234,120	17,049,798	51,702,360
2013 CDM Programs			26,392,837	26,096,288	52,489,125
2014 CDM Programs				40,178,891	40,178,891
Total in Year	**34,555,703**	**51,760,838**	**77,862,700**	**117,240,759**	**281,420,000**

	Weight Factor for Inclusion in CDM Adjustment to 2014 Load Forecast				
	2011	**2012**	**2013**	**2014**	
Weight Factor for each year's CDM program impact on 2014 load forecast	**0**	**0**	**0**	**0.5**	Utility can select "0", "0.5", or "1" from drop-down list
Default Value selection rationale.	*Persistence of 2011 CDM programs for the full year of 2012 means that all of 2011 CDM impact is assumed to be in the base forecast before the CDM Adjustment*	*50% of 2012 CDM impact is assumed reflected in base forecast based on 1/2 year rule.*	*Full year impact of 2013 CDM programs on adjustment for 2014 load forecast*	*Only 50% of 2014 CDM impact is used based on a half year rule*	

	2011	**2012**	**2013**	**2014**	**Total for 2014**
			kWh		
Amount used for CDM threshold for LRAMVA (2014)	33,915,782.57	17,049,797.72	26,096,288.27	40,178,890.59	117,240,759.16
Manual Adjustment for 2014 Load Forecast (billed basis)	-	-	-	21,763,566.00	21,763,566.00
Proposed Loss Factor (TLF)	1.04%	Format: X.XX%			
Manual Adjustment for 2014 Load Forecast (system purchased basis)	-	-	-	21,990,059.43	21,990,059.43

Manual adjustment uses "gross" versus "net" (i.e. numbers multiplied by (1 + g). The Weight factor is also used calculate the impact of each year's program on the CDM adjustment to the 2014 load forecast.
3

d) Based on the update to Table 3-5 above, Horizon Utilities has updated its CDM assumption for 2014 which has a cumulative impact on the CDM savings for the 2015 to 2019 rate plan term. Horizon Utilities has calculated that the impact of the CDM revision in 2014 on the revenue requirement over the rate plan term is $99,515 as shown in Table 1 below and the impact on the kWhs for the Residential, GS < 50 kW and GS > 50 kW is shown in Tables 2-4 below. Horizon Utilities has not revised the other Tables in the Application due to the minimal impact on revenue requirement.

Table 1: Revenue Requirement Impact

	2015	2016	2017	2018	2019
Base Revenue Requirement (As Filed)	$112,956,026	$118,628,501	$121,743,444	$123,920,317	$127,881,899
Base Revenue Requirement (Per 3-VECC-75TC)	$112,937,354	$118,609,576	$121,723,794	$123,899,661	$127,860,287
Difference	$18,672	$18,925	$19,649	$20,657	$21,612

Table 2: Revised Load Forecast per Update to Table 3-5

Year	Residential	GS < 50 kW	GS > 50 kW
2014	1,623,457,838	586,801,864	1,856,453,690
2015	1,610,835,523	583,669,812	1,848,170,566
2016	1,609,168,175	583,483,942	1,842,966,528
2017	1,601,729,710	580,981,669	1,831,308,912
2018	1,598,603,462	579,397,347	1,822,061,305
2019	1,594,350,980	577,737,768	1,812,733,238

Table 3: Load Forecast As Filed in Exhibit 3

Year	Residential	GS < 50 kW	GS > 50 kW
2014	1,630,039,291	589,101,097	1,862,301,069
2015	1,617,715,605	586,002,830	1,857,864,416
2016	1,615,569,770	585,648,636	1,852,830,462
2017	1,608,117,860	583,142,939	1,841,172,846
2018	1,604,991,612	581,558,617	1,831,925,238
2019	1,600,739,130	579,899,038	1,822,597,172

Table 4: kWh Variance and % Variance

Year	Residential	GS < 50 kW	GS > 50 kW
2014	(6,581,452)	(2,299,234)	(5,847,380)
2015	(6,880,082)	(2,333,019)	(9,693,849)
2016	(6,401,594)	(2,164,694)	(9,863,933)
2017	(6,388,150)	(2,161,270)	(9,863,933)
2018	(6,388,150)	(2,161,270)	(9,863,933)
2019	(6,388,150)	(2,161,270)	(9,863,933)
Year	**Residential**	**GS < 50 kW**	**GS > 50 kW**
2014	(0.41%)	(0.39%)	(0.31%)
2015	(0.43%)	(0.40%)	(0.52%)
2016	(0.40%)	(0.37%)	(0.54%)
2017	(0.40%)	(0.37%)	(0.54%)
2018	(0.40%)	(0.37%)	(0.54%)
2019	(0.40%)	(0.37%)	(0.54%)

Message from the Vice President:

The OPA is pleased to provide the enclosed Draft 2013 Verified Results Report. This report is designed to provide preliminary information on the Draft 2013 Verified Results and to help populate LDC Annual Report templates that will be submitted to the OEB in September.

Top Line Results:

- We have achieved 85% of our cumulative energy savings target and 49% of our annual peak demand savings target to date (Scenario 2), representing a 31% and 51% improvement over 2012 verified results respectively.
- The Business Programs continue to perform well, representing 74% of the cumulative energy savings and 69% of the annual peak demand savings (Scenario 1).
- There are currently three verified Process and System Upgrades projects contributing savings. Process and System Upgrades has a healthy pipeline of 22 contracted projects and 201 studies which will likely result in significant savings in 2014.

Please note that the 2013 Draft Verified Results within this report may vary from the unverified Q4 2013 Preliminary Unverified Report for the following reasons:

- Direct Install Lighting realization rate for peak demand savings has shown an increase of 19% since 2012.
- Retrofit realization rate for peak demand savings has declined by 2% and the net-to-gross ratio has declined by 3%. The realization rate and net-to-gross ratio have both declined by 4% for energy savings.
- Home Assistance Program realization rates have declined by 17% for peak demand and 11% for energy savings. The net-to-gross ratios remain the same at 100%.
- This report includes both the 2011 and 2012 adjustments. The adjustments analysis ensures that energy and demand savings are properly categorized in the year that they were achieved and that any variances identified after the release of the 2011 and 2012 Final Results Report are properly accounted for and reported to the LDCs. The adjustments will be identified in the year following implementation, while the cumulative effect will be accounted for in the implementation year.

These results are considered draft and may be subject to change. The OPA is committed to providing LDCs with the opportunity to review and provide feedback. To ensure that all inquiries can be directed to the appropriate OPA contact and addressed prior to the release of the 2013 Final Verified Results, please e-mail a list of questions and/or concerns to LDC Support (LDC.Support@powerauthority.on.ca) by Monday, August 11, 2014.

The Final 2013 Verified Results Report will be available to all LDCs on or before August 31, 2014. At that time, all results will be considered final for 2013. Any variances in 2013 program activity not captured will be reported in the Final 2014 Verified Results Report (to be issued in 2015), through the 2013 adjustments process.

We appreciate your collaboration and support throughout the reporting and evaluation process and we look forward to another successful year ahead.

Sincerely

Andrew Pride

Table of Contents

OPA-Contracted Province-Wide CDM Programs Draft Verified 2013 Results

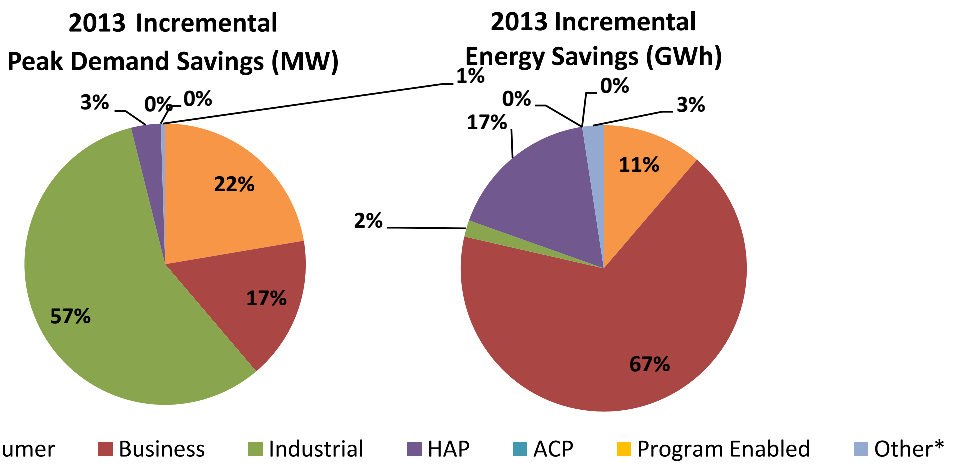
LDC: Horizon Utilities Corporation

FINAL 2013 Progress to Targets	2013 Incremental	Program-to-Date Progress to Target (Scenario 1)	Scenario 1: % of Target Achieved	Scenario 2: % of Target Achieved
Net Annual Peak Demand Savings (MW)	23.7	16.1	**26.6%**	**56.7%**
Net Energy Savings (GWh)	27.0	240.8	**85.6%**	**85.7%**

Scenario 1 = Assumes that demand response resources have a persistence of 1 year

Scenario 2 = Assumes that demand response resources remain in your territory until 2014

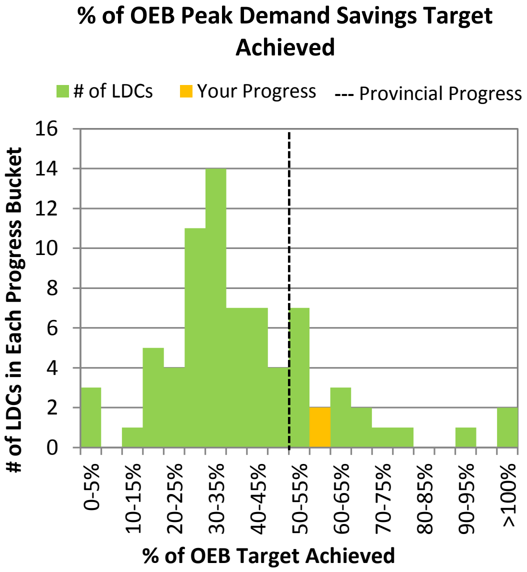
Achievement by Sector



**Other includes adjustments to previous years' results and savings from pre-2011 intiatives*

Comparison: Your Achievement vs. LDC Community Achievement (Progress to Target)

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



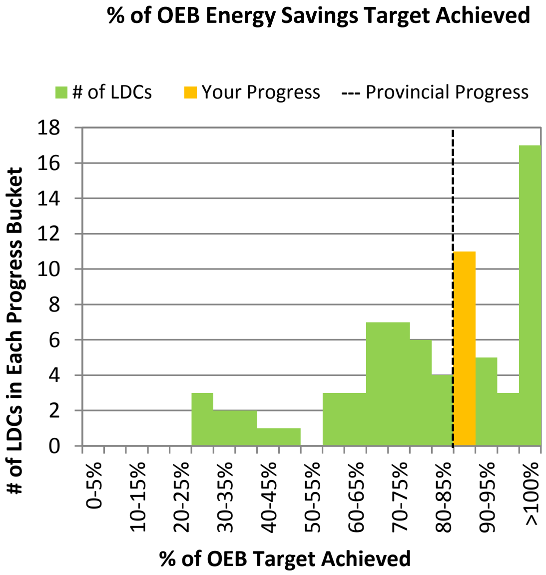


Table 1: **Horizon Utilities Corporation** Initiative and Program Level Net Savings by Year (Scenario 1)

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 Verified Progress to Target** (excludes DR)	
														2014 Net Annual Peak Demand Savings (kW)	**2011-2014 Net Cumulative Energy Savings (kWh)**
		2011*	**2012***	**2013**	**2014**	**2011**	**2012**	**2013**	**2014**	**2011**	**2012**	**2013**	**2014**	**2014**	**2014**
Consumer Program															
Appliance Retirement	Appliances	3,034	1,671	855		172	96	52		1,238,865	669,778	338,838		315	7,638,629
Appliance Exchange	Appliances	186	131	138		18	19	29		21,438	33,812	50,983		53	277,964
HVAC Incentives	Equipment	5,029	5,092	4,768		1,693	1,091	974		3,070,047	1,843,136	1,639,842		3,758	21,089,280
Conservation Instant Coupon Booklet	Items	21,872	1,249	14,024		50	9	21		810,293	56,527	311,606		80	4,033,967
Bi-Annual Retailer Event	Items	38,494	42,891	38,196		68	60	48		1,188,091	1,082,743	694,555		176	9,389,704
Retailer Co-op	Items	0	0	0		0	0	0		0	0	0		0	0
Residential Demand Response	Devices	1,952	5,393	9,566		1,093	2,699	4,176		2,830	13,650	12,020		0	28,500
Residential Demand Response (IHD)	Devices	0	3,855	8,374		0	0	0		0	0	0		0	0
Residential New Construction	Homes	0	0	0		0	0	0		0	0	0		0	0
Consumer Program Total						**3,093**	**3,975**	**5,300**		**6,331,565**	**3,699,646**	**3,047,843**		**4,382**	**42,458,045**
Business Program															
Retrofit	Projects	87	206	370		857	1,659	2,947		4,805,916	9,600,471	16,353,441		5,308	80,167,029
Direct Install Lighting	Projects	715	662	415		661	550	453		1,693,346	1,875,038	1,442,489		1,531	14,816,492
Building Commissioning	Buildings	0	0	0		0	0	0		0	0	0		0	0
New Construction	Buildings	0	2	3		0	0	6		0	1,331	20,831		6	45,654
Energy Audit	Audits	15	4	8		0	16	71		0	75,529	387,606		86	1,001,799
Small Commercial Demand Response	Devices	0	9	20		0	6	13		0	33	20		0	53
Small Commercial Demand Response (IHD)	Devices	0	0	15		0	0	0		0	0	0		0	0
Demand Response 3	Facilities	5	4	5		536	531	418		20,936	7,718	-1,735		0	26,919
Business Program Total						**2,054**	**2,762**	**3,907**		**6,520,199**	**11,560,119**	**18,202,652**		**6,931**	**96,057,946**
Industrial Program															
Process & System Upgrades	Projects	0	0	0		0	0	0		0	0	0		0	0
Monitoring & Targeting	Projects	0	0	0		0	0	0		0	0	0		0	0
Energy Manager	Projects	0	3	5		0	60	23		0	479,921	178,203		77	1,744,203
Retrofit	Projects	15	0	0		70	0	0		402,527	0	0		70	1,610,107
Demand Response 3	Facilities	6	7	9		3,498	6,445	13,579		205,346	155,311	329,778		0	690,435
Industrial Program Total						**3,568**	**6,505**	**13,602**		**607,873**	**635,233**	**507,980**		**147**	**4,044,745**
Home Assistance Program															
Home Assistance Program	Homes	0	235	3,550		0	24	808		0	286,839	4,634,362		832	10,129,240
Home Assistance Program Total						**0**	**24**	**808**		**0**	**286,839**	**4,634,362**		**832**	**10,129,240**
Aboriginal Program															
Home Assistance Program	Homes	0	0	0		0	0	0		0	0	0		0	0
Direct Install Lighting	Projects	0	0	0		0	0	0		0	0	0		0	0
Aboriginal Program Total						**0**	**0**	**0**		**0**	**0**	**0**		**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	118	0	0		3,066	0	0		17,700,219	0	0		3,066	70,800,874
High Performance New Construction	Projects	8	3	0		242	146	0		1,244,589	582,164	0		389	6,724,846
Toronto Comprehensive	Projects	0	0	0		0	0	0		0	0	0		0	0
Multifamily Energy Efficiency Rebates	Projects	0	0	0		0	0	0		0	0	0		0	0
LDC Custom Programs	Projects	0	0	0		0	0	0		0	0	0		0	0
Pre-2011 Programs completed in 2011 Total						**3,308**	**146**	**0**		**18,944,807**	**582,164**	**0**		**3,455**	**77,525,721**
Other															
Program Enabled Savings	Projects	0	0	0		0	0	0		0	0	0		0	0
Time-of-Use Savings	Homes	0	0	0		0	0	0		0	0	0		0	0
Other Total						**0**	**0**	**0**		**0**	**0**	**0**		**0**	**0**
Adjustments to 2011 Verified Results							**193**	**0**			**2,151,259**	**0**		**191**	**8,600,509**
Adjustments to 2012 Verified Results								**119**				**654,441**		**116**	**1,952,775**
Energy Efficiency Total						**6,896**	**3,730**	**5,431**		**32,175,331**	**16,587,289**	**26,052,755**		**15,747**	**229,469,789**
Demand Response Total (Scenario 1)						**5,128**	**9,681**	**18,186**		**229,113**	**176,712**	**340,083**		**0**	**745,907**
Adjustments to Previous Year's Verified Results Total						**0**	**193**	**119**		**0**	**2,151,259**	**654,441**		**307**	**10,553,283**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**12,023**	**13,604**	**23,736**		**32,404,444**	**18,915,260**	**27,047,278**		**16,054**	**240,768,979**
													Full OEB Target:	**60,360**	**281,420,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**26.6%**	**85.6%**

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

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

*Includes adjustments after Final Reports were issued

Table 2: Adjustments to **Horizon Utilities Corporation** Net Verified Results due to Variances

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)			
		2011*	2012*	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program													
Appliance Retirement	Appliances	0	0			0	0			0	0		
Appliance Exchange	Appliances	0	0			0	0			0	0		
HVAC Incentives	Equipment	-1,069	85			-298	16			-545,322	30,760		
Conservation Instant Coupon Booklet	Items	332	0			1	0			11,144	0		
Bi-Annual Retailer Event	Items	3,308	0			4	0			88,271	0		
Retailer Co-op	Items	0	0			0	0			0	0		
Residential Demand Response	Devices	0	0			0	0			0	0		
Residential Demand Response (IHD)	Devices	0	0			0	0			0	0		
Residential New Construction	Homes	0	0			0	0			0	0		
Consumer Program Total						**-293**	**16**			**-445,907**	**30,760**		
Business Program													
Retrofit	Projects	16	28			112	102			615,841	623,681		
Direct Install Lighting	Projects	22	0			28	0			60,847	0		
Building Commissioning	Buildings	0	0			0	0			0	0		
New Construction	Buildings	0	0			0	0			0	0		
Energy Audit	Audits	10	1			52	0			251,763	0		
Small Commercial Demand Response	Devices	0	0			0	0			0	0		
Small Commercial Demand Response (IHD)	Devices	0	0			0	0			0	0		
Demand Response 3	Facilities	0	0			0	0			0	0		
Business Program Total						**191**	**102**			**928,450**	**623,681**		
Industrial Program													
Process & System Upgrades	Projects	0	0			0	0			0	0		
Monitoring & Targeting	Projects	0	0			0	0			0	0		
Energy Manager	Projects	0	0			0	0			0	0		
Retrofit	Projects	0	0			0	0			0	0		
Demand Response 3	Facilities	0	0			0	0			0	0		
Industrial Program Total						**0**	**0**			**0**	**0**		
Home Assistance Program													
Home Assistance Program	Homes	0	0			0	0			0	0		
Home Assistance Program Total						**0**	**0**			**0**	**0**		
Aboriginal Program													
Home Assistance Program	Homes	0	0			0	0			0	0		
Direct Install Lighting	Projects	0	0			0	0			0	0		
Aboriginal Program Total						**0**	**0**			**0**	**0**		
Pre-2011 Programs completed in 2011													
Electricity Retrofit Incentive Program	Projects	0	0			0	0			0	0		
High Performance New Construction	Projects	1	0			295	0			1,668,716	0		
Toronto Comprehensive	Projects	0	0			0	0			0	0		
Multifamily Energy Efficiency Rebates	Projects	0	0			0	0			0	0		
LDC Custom Programs	Projects	0	0			0	0			0	0		
Pre-2011 Programs completed in 2011 Total						**295**	**0**			**1,668,716**	**0**		
Other													
Program Enabled Savings	Projects	0	0			0	0			0	0		
Time-of-Use Savings	Homes	0	0			0	0			0	0		
Other Total						**0**	**0**			**0**	**0**		
Adjustments to 2011 Verified Results						**193**				**2,151,259**			
Adjustments to 2012 Verified Results							**119**				**654,441**		
Total Adjustments to Previous Year's Verified Results						**193**	**119**			**2,151,259**	**654,441**		

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

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

Adjustments to previous years' results shown in this table will not align to adjustments shown in Table 1 as the information presented above does not consider persistence of savings

Table 3: Horizon Utilities Corporation Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement	1.00	1.00	n/a		0.51	0.46	0.42		1.00	1.00	n/a		0.51	0.47	0.44	
Appliance Exchange	1.00	1.00	1.00		0.52	0.52	0.53		1.00	1.00	1.00		0.52	0.52	0.53	
HVAC Incentives	1.00	1.00	n/a		0.61	0.50	0.48		1.00	1.00	n/a		0.60	0.49	0.48	
Conservation Instant Coupon Booklet	1.00	1.00	1.00		1.14	1.00	1.11		1.00	1.00	1.00		1.11	1.05	1.13	
Bi-Annual Retailer Event	1.00	1.00	1.00		1.13	0.91	1.04		1.00	1.00	1.00		1.10	0.92	1.04	
Retailer Co-op	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Residential Demand Response	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Residential Demand Response (IHD)	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Residential New Construction	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Business Program																
Retrofit	0.95	0.94	0.95		0.72	0.76	0.75		1.23	1.07	1.04		0.74	0.76	0.74	
Direct Install Lighting	1.08	0.68	0.81		0.93	0.94	0.94		0.90	0.85	0.84		0.93	0.94	0.94	
Building Commissioning	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
New Construction	n/a	0.68	0.53		n/a	0.49	0.54		n/a	0.86	0.73		n/a	0.49	0.54	
Energy Audit	n/a	n/a	1.02		n/a	n/a	0.66		n/a	n/a	0.97		n/a	n/a	0.66	
Small Commercial Demand Response	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Small Commercial Demand Response (IHD)	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Demand Response 3	0.76	n/a	n/a		n/a	n/a	n/a		1.00	n/a	n/a		n/a	n/a	n/a	
Industrial Program																
Process & System Upgrades	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Monitoring & Targeting	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Energy Manager	n/a	1.31	0.90		n/a	0.90	0.90		n/a	1.31	0.90		n/a	0.90	0.90	
Retrofit																
Demand Response 3	0.84	n/a	n/a		n/a	n/a	n/a		1.00	n/a	n/a		n/a	n/a	n/a	
Home Assistance Program																
Home Assistance Program	n/a	1.27	3.71		n/a	1.00	1.00		n/a	1.00	0.90		n/a	1.00	1.00	
Aboriginal Program																
Home Assistance Program	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Direct Install Lighting	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program	0.77	n/a	n/a		0.52	n/a	n/a		0.78	n/a	n/a		0.52	n/a	n/a	
High Performance New Construction	1.00	1.00	1.00		0.50	0.50	0.50		1.00	1.00	1.00		0.50	0.50	0.50	
Toronto Comprehensive	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Multifamily Energy Efficiency Rebates	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
LDC Custom Programs	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Other																
Program Enabled Savings	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Time-of-Use Savings	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	

Summary Progress Towards CDM Targets

Results are attributed to target using current OPA reporting policies. Energy efficiency resources persist for the duration of the effective useful life. Any upcoming code changes are taken into account. Demand response resources persist for 1 year (Scenerio 1). Please see methodology tab for more detailed information.

Table 4: Net Peak Demand Savings at the End User Level (MW) (Scenerio 1)

Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	12.0	6.9	6.9	6.8
2012 - Verified†	0.2	13.6	3.9	3.8
2013 - Verified†	0.0	0.1	23.7	5.4
2014				
Verified Net Annual Peak Demand Savings Persisting in 2014:				**16.1**
Horizon Utilities Corporation 2014 Annual CDM Capacity Target:				**60.4**
Verified Portion of Peak Demand Savings Target Achieved in 2014 (%):				**26.6%**

Table 5: Net Energy Savings at the End User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	32.4	32.2	32.1	31.8	128.5
2012 - Verified†	2.2	18.9	18.7	18.5	58.2
2013 - Verified†	0.0	0.7	27.0	26.4	54.1
2014					
Verified Net Cumulative Energy Savings 2011-2014:					**240.8**
Horizon Utilities Corporation 2011-2014 Annual CDM Energy Target:					**281.4**
Verified Portion of Cumulative Energy Target Achieved in 2014 (%):					**85.6%**

† Includes adjustments to previous year's verified results

Table 6: Province-Wide Initiatives and Program Level Net Savings by Year (Scenerio 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 Verified Progress to Target (excludes DR)	
														2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
		2011*	2012*	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	56,110	34,146	20,014		3,299	2,011	1,272		23,005,812	13,424,518	7,746,950		6,443	147,670,757
Appliance Exchange	Appliances	3,688	3,836	4,378		371	556	907		450,187	974,621	1,617,408		1,597	7,747,341
HVAC Incentives	Equipment	92,743	87,427	91,581		32,037	19,060	19,552		59,437,670	32,841,283	33,923,592		70,650	404,121,713
Conservation Instant Coupon Booklet	Items	567,678	30,891	346,896		1,344	230	517		21,211,537	1,398,202	7,707,573		2,091	104,455,900
Bi-Annual Retailer Event	Items	952,149	1,060,901	944,772		1,681	1,480	1,184		29,387,468	26,781,674	17,179,841		4,345	232,254,579
Retailer Co-op	Items	152	0	0		0	0	0		2,652	0	0		0	10,607
Residential Demand Response	Devices	19,550	98,388	171,796		10,947	49,038	95,869		24,870	359,408	263,461		0	647,740
Residential Demand Response (IHD)	Devices	0	49,689	133,717		0	0	0		0	0	0		0	0
Residential New Construction	Homes	26	19	86		0	2	16		743	17,152	163,690		18	381,811
Consumer Program Total						**49,681**	**72,377**	**119,317**		**133,520,941**	**75,796,859**	**68,602,515**		**85,144**	**897,290,448**
Business Program															
Retrofit	Projects	2,819	6,093	8,757		24,467	61,147	59,509		136,002,258	314,922,468	344,604,758		142,664	2,167,023,694
Direct Install Lighting	Projects	20,741	18,691	17,782		23,724	15,284	18,708		61,076,701	57,345,798	64,315,558		49,886	519,693,356
Building Commissioning	Buildings	0	0	0		0	0	0		0	0	0		0	0
New Construction	Buildings	22	69	85		123	764	1,584		411,717	1,814,721	4,959,266		2,472	17,009,564
Energy Audit	Audits	198	345	319		0	1,450	2,653		0	7,049,351	14,583,681		4,102	50,315,416
Small Commercial Demand Response	Devices	132	294	1,211		84	187	773		157	1,068	1,297		0	2,521
Small Commercial Demand Response (IHD)	Devices	0	0	378		0	0	0		0	0	0		0	0
Demand Response 3	Facilities	145	151	175		16,218	19,389	26,338		633,421	281,823	294,024		0	1,209,268
Business Program Total						**64,617**	**98,221**	**109,564**		**198,124,253**	**381,415,230**	**428,758,583**		**199,124**	**2,755,253,819**
Industrial Program															
Process & System Upgrades	Projects	0	0	3		0	0	294		0	0	2,603,764		294	5,207,528
Monitoring & Targeting	Projects	0	0	0		0	0	0		0	0	0		0	0
Energy Manager	Projects	0	39	205		0	1,086	3,558		0	7,372,108	21,019,100		3,194	53,752,948
Retrofit	Projects	433	0	0		4,615	0	0		28,866,840	0	0		4,613	115,462,282
Demand Response 3	Facilities	124	185	281		52,484	74,056	165,132		3,080,737	1,784,712	4,245,451		0	9,110,900
Industrial Program Total						**57,098**	**75,141**	**168,984**		**31,947,577**	**9,156,820**	**27,868,315**		**8,101**	**183,533,657**
Home Assistance Program															
Home Assistance Program	Homes	46	5,033	26,756		2	566	2,361		39,283	5,442,232	20,987,275		2,930	58,458,380
Home Assistance Program Total						**2**	**566**	**2,361**		**39,283**	**5,442,232**	**20,987,275**		**2,930**	**58,458,380**
Aboriginal Program															
Home Assistance Program	Homes	0	0	584		0	0	267		0	0	1,609,393		267	3,218,786
Direct Install Lighting	Projects	0	0	0		0	0	0		0	0	0		0	0
Aboriginal Program Total						**0**	**0**	**267**		**0**	**0**	**1,609,393**		**267**	**3,218,786**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	2,028	0	0		21,662	0	0		121,138,219	0	0		21,662	484,552,876
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
Toronto Comprehensive	Projects	577	0	0		15,805	0	0		86,964,886	0	0		15,805	347,859,545
Multifamily Energy Efficiency Rebates	Projects	110	0	0		1,981	0	0		7,595,683	0	0		1,981	30,382,733
LDC Custom Programs	Projects	8	0	0		399	0	0		1,367,170	0	0		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															
Program Enabled Savings	Projects	14	55	12		0	2,304	2,979		0	1,188,362	1,160,045		5,283	5,885,176
Time-of-Use Savings	Homes	0	0	0		0	0	0		0	0	0		0	0
Other Total						**0**	**2,304**	**2,979**		**0**	**1,188,362**	**1,160,045**		**5,283**	**5,885,176**
Adjustments to 2011 Verified Results							**1,406**	**630**			**18,689,081**	**1,686,028**		**1,786**	**80,662,711**
Adjustments to 2012 Verified Results								**5,550**				**35,137,715**		**5,479**	**105,167,899**
Energy Efficiency Total						**136,610**	**109,191**	**116,133**		**603,144,419**	**482,474,435**	**547,704,133**		**349,816**	**4,908,426,347**
Demand Response Total (Scenario 1)						**79,733**	**142,670**	**288,112**		**3,739,185**	**2,427,011**	**4,804,233**		**0**	**10,970,429**
Adjustments to Previous Year's Verified Results Total						**0**	**1,406**	**6,181**		**0**	**18,689,081**	**36,823,743**		**7,265**	**185,830,610**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**216,343**	**253,267**	**410,426**		**606,883,604**	**503,590,526**	**589,332,109**		**357,082**	**5,105,227,386**
													Full OEB Target:	**1,330,000**	**6,000,000,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**26.8%**	**85.1%**

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

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

*Includes adjustments after Final Reports were issued

Table 7: Adjustments to **Province-Wide** Net Verified Results due to Variances

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)			
		2011*	2012*	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program													
Appliance Retirement	Appliances	0	0			0	0			0	0		
Appliance Exchange	Appliances	0	0			0	0			0	0		
HVAC Incentives	Equipment	-18,844	2,206			-5,271	452			-9,709,500	907,735		
Conservation Instant Coupon Booklet	Items	8,216	0			16	0			275,655	0		
Bi-Annual Retailer Event	Items	81,817	0			108	0			2,183,391	0		
Retailer Co-op	Items	0	0			0	0			0	0		
Residential Demand Response	Devices	0	0			0	0			0	0		
Residential Demand Response (IHD)	Devices	0	0			0	0			0	0		
Residential New Construction	Homes	19	0			1	0			13,767	0		
Consumer Program Total						**-5,146**	**452**			**-7,236,687**	**907,735**		
Business Program													
Retrofit	Projects	303	488			3,204	4,183			16,216,165	27,458,566		
Direct Install Lighting	Projects	444	197			501	204			1,250,388	736,541		
Building Commissioning	Buildings	0	0			0	0			0	0		
New Construction	Buildings	12	0			828	0			3,520,620	0		
Energy Audit	Audits	95	65			481	0			2,341,392	0		
Small Commercial Demand Response	Devices	0	0			0	0			0	0		
Small Commercial Demand Response (IHD)	Devices	0	0			0	0			0	0		
Demand Response 3	Facilities	0	0			0	0			0	0		
Business Program Total						**5,014**	**4,387**			**23,328,565**	**28,195,107**		
Industrial Program													
Process & System Upgrades	Projects	0	0			0	0			0	0		
Monitoring & Targeting	Projects	0	0			0	0			0	0		
Energy Manager	Projects	0	0			0	0			0	0		
Retrofit	Projects	0	0			0	0			0	0		
Demand Response 3	Facilities	0	0			0	0			0	0		
Industrial Program Total						**0**	**0**			**0**	**0**		
Home Assistance Program													
Home Assistance Program	Homes	0	0			0	0			0	0		
Home Assistance Program Total						**0**	**0**			**0**	**0**		
Aboriginal Program													
Home Assistance Program	Homes	0	0			0	0			0	0		
Direct Install Lighting	Projects	0	0			0	0			0	0		
Aboriginal Program Total						**0**	**0**			**0**	**0**		
Pre-2011 Programs completed in 2011													
Electricity Retrofit Incentive Program	Projects	12	0			138	0			545,536	0		
High Performance New Construction	Projects	34	0			1,407	0			2,065,200	0		
Toronto Comprehensive	Projects	0	0			0	0			0	0		
Multifamily Energy Efficiency Rebates	Projects	0	0			0	0			0	0		
LDC Custom Programs	Projects	0	0			0	0			0	0		
Pre-2011 Programs completed in 2011 Total						**1,545**	**0**			**2,610,736**	**0**		
Other													
Program Enabled Savings	Projects	14	39			624	711			1,673,712	6,034,873		
Time-of-Use Savings	Homes	0	0			0	0			0	0		
Other Total						**624**	**711**			**1,673,712**	**6,034,873**		
Adjustments to 2011 Verified Results						**2,037**				**20,376,325**			
Adjustments to 2012 Verified Results							**5,550**				**35,137,715**		
Adjustments to Previous Year's Verified Results Total						**2,037**	**5,550**			**20,376,325**	**35,137,715**		

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

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

Adjustments to previous years' results shown in this table will not align to adjustments shown in Table 1 as the information presented above does not consider persistence of savings

Table 8: Province-Wide Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement	1.00	1.00	1.00		0.51	0.46	0.42		1.00	1.00	1.00		0.46	0.47	0.44	
Appliance Exchange	1.00	1.00	1.00		0.51	0.52	0.53		1.00	1.00	1.00		0.52	0.52	0.53	
HVAC Incentives	1.00	1.00	1.00		0.60	0.50	0.48		1.00	1.00	1.00		0.50	0.49	0.48	
Conservation Instant Coupon Booklet	1.00	1.00	1.00		1.14	1.00	1.11		1.00	1.00	1.00		1.00	1.05	1.13	
Bi-Annual Retailer Event	1.00	1.00	1.00		1.12	0.91	1.04		1.00	1.00	1.00		0.91	0.92	1.04	
Retailer Co-op	1.00	n/a	n/a		0.68	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Residential Demand Response	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Residential Demand Response (IHD)	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Residential New Construction	1.00	3.65	0.78		0.41	0.49	0.63		3.65	7.17	3.09		0.49	0.49	0.63	
Business Program																
Retrofit	1.06	0.93	0.92		0.72	0.75	0.73		0.93	1.05	1.01		0.75	0.76	0.73	
Direct Install Lighting	1.08	0.69	0.82		1.08	0.94	0.94		0.69	0.85	0.84		0.94	0.94	0.94	
Building Commissioning	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
New Construction	0.50	0.98	0.68		0.50	0.49	0.54		0.98	0.99	0.76		0.49	0.49	0.54	
Energy Audit	n/a	n/a	1.02		n/a	n/a	0.66		n/a	n/a	0.97		n/a	n/a	0.66	
Small Commercial Demand Response	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Small Commercial Demand Response (IHD)	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Demand Response 3	0.76	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Industrial Program																
Process & System Upgrades	n/a	n/a	0.85		n/a	n/a	0.94		n/a	n/a	0.87		n/a	n/a	0.93	
Monitoring & Targeting	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Energy Manager	n/a	1.16	0.90		n/a	0.90	0.90		1.16	1.16	0.90		0.90	0.90	0.90	
Retrofit	1.11	n/a	n/a		0.72	n/a	n/a		0.91	n/a	n/a		0.75	n/a	n/a	
Demand Response 3	0.84	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Home Assistance Program																
Home Assistance Program	1.00	0.32	0.26		0.70	1.00	1.00		0.32	0.99	0.88		1.00	1.00	1.00	
Aboriginal Program																
Home Assistance Program	n/a	n/a	0.05		n/a	n/a	1.00		n/a	n/a	0.95		n/a	n/a	1.00	
Direct Install Lighting	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program	0.80	n/a	n/a		0.54	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
High Performance New Construction	1.00	1.00	1.00		0.49	0.50	0.50		1.00	1.00	1.00		0.50	0.50	0.50	
Toronto Comprehensive	1.13	n/a	n/a		0.50	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Multifamily Energy Efficiency Rebates	0.93	n/a	n/a		0.78	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
LDC Custom Programs	1.00	n/a	n/a		1.00	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Other																
Program Enabled Savings	n/a	1.06	1.00		n/a	1.00	1.00		1.06	2.26	1.00		1.00	1.00	1.00	
Time-of-Use Savings	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	

Summary Provincial Progress Towards CDM Targets

Table 9: Province-Wide Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011	216.3	136.6	135.8	129.0
2012†	1.4	253.3	109.8	108.2
2013†	0.6	6.2	410.4	119.9
2014				
Verified Net Annual Peak Demand Savings in 2014:				**357.1**
2014 Annual CDM Capacity Target:				**1,330**
Verified Portion of Peak Demand Savings Target Achieved in 2014 (%):				**26.8%**

Table 10: Province-Wide Net Energy Savings at the End-User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011	606.9	603.0	601.0	582.3	2,393.1
2012†	18.7	503.6	498.4	492.6	1,513.2
2013†	1.7	36.8	589.3	571.0	1,198.9
2014					
Verified Net Cumulative Energy Savings 2011-2014:					**5,105.2**
2011-2014 Cumulative CDM Energy Target:					**6,000**
Verified Portion of Cumulative Energy Target Achieved in 2014 (%):					**85.1%**

† Includes adjustments to previous year's verified results

METHODOLOGY

All results are at the end-user level (not including transmission and distribution losses)

EQUATIONS	
Prescriptive Measures and Projects	**Gross Savings =** Activity * Per Unit Assumption **Net Savings =** Gross Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
Engineered and Custom Projects	**Gross Savings =** Reported Savings * Realization Rate **Net Savings =** Gross Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
Demand Response	**Peak Demand: Gross Savings = Net Savings =** contracted MW at contributor level * Provincial contracted to ex ante ratio **Energy: Gross Savings = Net Savings =** provincial ex post energy savings * LDC proportion of total provincial contracted MW All savings are annualized (i.e. the savings are the same regardless of the time of year a participant began offering DR)
Adjustments to Previous Year's Verified Results	All variances from the Final Annual Results Reports from prior years will be adjusted within this report. Any variances with regards to projects counts, data lag, and calculations etc., will be made within this report. Considers the cumulative effect of energy savings.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Consumer Program			
Appliance Retirement	Includes both retail and home pickup stream; Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection	Savings are considered to begin in the year the appliance is picked up.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Appliance Exchange	When postal code information is provided by customer, results are directly attributed to the LDC. When postal code is not available, results allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year that the exchange event occurred	
HVAC Incentives	Results directly attributed to LDC based on customer postal code	Savings are considered to begin in the year that the installation occurred	

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year in which the coupon was redeemed.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Bi-Annual Retailer Event	Results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year in which the event occurs.	
Retailer Co-op	When postal code information is provided by the customer, results are directly attributed. If postal code information is not available, results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year of the home visit and installation date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Residential Demand Response	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year and accounts for any "snapback" in energy consumption experienced after the event. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year of the project completion date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Business Program			
Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see page for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
	Additional Note: project counts were derived by filtering out invalid statuses (e.g. Post-Project Submission - Payment denied by LDC) and only including projects with an "Actual Project Completion Date" in 2013)		

<table>
<tr><th>Initiative</th><th>Attributing Savings to LDCs</th><th>Savings 'start' Date</th><th>Calculating Resource Savings</th></tr>
<tr><td>Direct Installed Lighting</td><td>Results are directly attributed to LDC based on the LDC specified on the work order</td><td>Savings are considered to begin in the year of the actual project completion date.</td><td>Peak demand and energy savings are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).</td></tr>
<tr><td>Existing Building Commissioning Incentive</td><td>Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011 or 2012.</td><td>Savings are considered to begin in the year of the actual project completion date.</td><td rowspan="2">Peak demand and energy savings are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).</td></tr>
<tr><td>New Construction and Major Renovation Incentive</td><td>Results are directly attributed to LDC based on LDC identified in the application.</td><td>Savings are considered to begin in the year of the actual project completion date.</td></tr>
<tr><td>Energy Audit</td><td>Projects are directly attributed to LDC based on LDC identified in the application</td><td>Savings are considered to begin in the year of the audit date.</td><td>Peak demand and energy savings are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).</td></tr>
</table>

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Commercial Demand Response (part of the Residential program schedule)	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.
Demand Response 3 (part of the Industrial program schedule)	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Industrial Program			
Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Monitoring & Targeting	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011, 2012 or 2013.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
Energy Manager	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
Demand Response 3	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Home Assistance Program			
Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.	**Peak demand and energy savings** are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Aboriginal Program			
Aboriginal Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.	**Peak demand and energy savings** are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Pre-2011 Programs completed in 2011			
Electricity Retrofit Incentive Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, 2012 or 2013 assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
High Performance New Construction	Results are directly attributed to LDC based on customer data provided to the OPA from Enbridge; Initiative was not evaluated in 2011, 2012 or 2013, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	
Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Limited service territory; Initiative was not evaluated in 2011, 2012 or 2013, assumptions as per 2010 evaluation		

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Multifamily Energy Efficiency Rebates	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, 2012 or 2013, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
Data Centre Incentive Program	Program run exclusively in PowerStream Inc. service territory; Initiative was not evaluated in 2011, assumptions as per 2009 evaluation		
EnWin Green Suites	Program run exclusively in ENWIN Utilities Ltd. service territory; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation		

Retrofit Sector (C&I vs. Industrial Mapping)	
Building Type	**Sector**
Agribusiness - Cattle Farm	C&I
Agribusiness - Dairy Farm	C&I
Agribusiness - Greenhouse	C&I
Agribusiness - Other	C&I
Agribusiness - Other,Mixed-Use - Office/Retail	C&I
Agribusiness - Other,Office,Retail,Warehouse	C&I
Agribusiness - Other,Office,Warehouse	C&I
Agribusiness - Poultry	C&I
Agribusiness - Poultry,Hospitality - Motel	C&I
Agribusiness - Swine	C&I
Convenience Store	C&I
Education - College / Trade School	C&I
Education - College / Trade School,Multi-Residential - Condominium	C&I
Education - College / Trade School,Multi-Residential - Rental Apartment	C&I
Education - College / Trade School,Retail	C&I
Education - Primary School	C&I
Education - Primary School,Education - Secondary School	C&I
Education - Primary School,Multi-Residential - Rental Apartment	C&I
Education - Primary School,Not-for-Profit	C&I
Education - Secondary School	C&I
Education - University	C&I
Education - University,Office	C&I
Hospital/Healthcare - Clinic	C&I
Hospital/Healthcare - Clinic,Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Clinic,Industrial	C&I
Hospital/Healthcare - Clinic,Retail	C&I
Hospital/Healthcare - Long-term Care	C&I
Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail,Office	C&I
Hospitality - Hotel	C&I
Hospitality - Hotel,Restaurant - Dining	C&I
Hospitality - Motel	C&I
Industrial	Industrial
Mixed-Use - Office/Retail	C&I
Mixed-Use - Office/Retail,Industrial	Industrial
Mixed-Use - Office/Retail,Mixed-Use - Other	C&I
Mixed-Use - Office/Retail,Mixed-Use - Other,Not-for-Profit,Warehouse	C&I
Mixed-Use - Office/Retail,Mixed-Use - Residential/Retail	C&I
Mixed-Use - Office/Retail,Office,Restaurant - Dining,Restaurant - Quick Serve,Retail,Warehouse	C&I

Mixed-Use - Office/Retail,Office,Warehouse	C&I
Mixed-Use - Office/Retail,Retail	C&I
Mixed-Use - Office/Retail,Warehouse	C&I
Mixed-Use - Office/Retail,Warehouse,Industrial	Industrial
Mixed-Use - Other	C&I
Mixed-Use - Other,Industrial	Industrial
Mixed-Use - Other,Not-for-Profit,Office	C&I
Mixed-Use - Other,Office	C&I
Mixed-Use - Other,Other: Please specify	C&I
Mixed-Use - Other,Retail,Warehouse	C&I
Mixed-Use - Other,Warehouse	C&I
Mixed-Use - Residential/Retail	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Condominium	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Rental Apartment	C&I
Mixed-Use - Residential/Retail,Retail	C&I
Multi-Residential - Condominium	C&I
Multi-Residential - Condominium,Multi-Residential - Rental Apartment	C&I
Multi-Residential - Condominium,Other: Please specify	C&I
Multi-Residential - Rental Apartment	C&I
Multi-Residential - Rental Apartment,Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Warehouse	C&I
Multi-Residential - Social Housing Provider	C&I
Multi-Residential - Social Housing Provider,Industrial	C&I
Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Not-for-Profit	C&I
Not-for-Profit,Office	C&I
Not-for-Profit,Other: Please specify	C&I
Not-for-Profit,Warehouse	C&I
Office	C&I
Office,Industrial	Industrial
Office,Other: Please specify	C&I
Office,Other: Please specify,Warehouse	C&I
Office,Restaurant - Dining	C&I
Office,Restaurant - Dining,Industrial	Industrial
Office,Retail	C&I
Office,Retail,Industrial	C&I
Office,Retail,Warehouse	C&I
Office,Warehouse	C&I
Office,Warehouse,Industrial	Industrial
Other: Please specify	C&I
Other: Please specify,Industrial	Industrial
Other: Please specify,Retail	C&I
Other: Please specify,Warehouse	C&I
Restaurant - Dining	C&I
Restaurant - Dining,Retail	C&I

Restaurant - Quick Serve	C&I
Restaurant - Quick Serve,Retail	C&I
Retail	C&I
Retail,Industrial	Industrial
Retail,Warehouse	C&I
Warehouse	C&I
Warehouse,Industrial	Industrial

Consumer Program Allocation Methodology

Results can be allocated based on average of 2008 & 2009 residential throughput for each LDC (below) when additional information is not available. Source: OEB Yearbook Data 2008 & 2009

Local Distribution Company	Allocation
Algoma Power Inc.	0.2%
Atikokan Hydro Inc.	0.0%
Attawapiskat Power Corporation	0.0%
Bluewater Power Distribution Corporation	0.6%
Brant County Power Inc.	0.2%
Brantford Power Inc.	0.7%
Burlington Hydro Inc.	1.4%
Cambridge and North Dumfries Hydro Inc.	1.0%
Canadian Niagara Power Inc.	0.5%
Centre Wellington Hydro Ltd.	0.1%
Chapleau Public Utilities Corporation	0.0%
COLLUS Power Corporation	0.3%
Cooperative Hydro Embrun Inc.	0.0%
E.L.K. Energy Inc.	0.2%
Enersource Hydro Mississauga Inc.	3.9%
ENTEGRUS	0.6%
ENWIN Utilities Ltd.	1.6%
Erie Thames Powerlines Corporation	0.4%
Espanola Regional Hydro Distribution Corporation	0.1%
Essex Powerlines Corporation	0.7%
Festival Hydro Inc.	0.3%
Fort Albany Power Corporation	0.0%
Fort Frances Power Corporation	0.1%
Greater Sudbury Hydro Inc.	1.0%
Grimsby Power Inc.	0.2%
Guelph Hydro Electric Systems Inc.	0.9%
Haldimand County Hydro Inc.	0.4%
Halton Hills Hydro Inc.	0.5%
Hearst Power Distribution Company Limited	0.1%
Horizon Utilities Corporation	4.0%
Hydro 2000 Inc.	0.0%
Hydro Hawkesbury Inc.	0.1%
Hydro One Brampton Networks Inc.	2.8%
Hydro One Networks Inc.	30.0%

Hydro Ottawa Limited	5.6%
Innisfil Hydro Distribution Systems Limited	0.4%
Kashechewan Power Corporation	0.0%
Kenora Hydro Electric Corporation Ltd.	0.1%
Kingston Hydro Corporation	0.5%
Kitchener-Wilmot Hydro Inc.	1.6%
Lakefront Utilities Inc.	0.2%
Lakeland Power Distribution Ltd.	0.2%
London Hydro Inc.	2.7%
Middlesex Power Distribution Corporation	0.1%
Midland Power Utility Corporation	0.1%
Milton Hydro Distribution Inc.	0.6%
Newmarket - Tay Power Distribution Ltd.	0.7%
Niagara Peninsula Energy Inc.	1.0%
Niagara-on-the-Lake Hydro Inc.	0.2%
Norfolk Power Distribution Inc.	0.3%
North Bay Hydro Distribution Limited	0.5%
Northern Ontario Wires Inc.	0.1%
Oakville Hydro Electricity Distribution Inc.	1.5%
Orangeville Hydro Limited	0.2%
Orillia Power Distribution Corporation	0.3%
Oshawa PUC Networks Inc.	1.2%
Ottawa River Power Corporation	0.2%
Parry Sound Power Corporation	0.1%
Peterborough Distribution Incorporated	0.7%
PowerStream Inc.	6.6%
PUC Distribution Inc.	0.9%
Renfrew Hydro Inc.	0.1%
Rideau St. Lawrence Distribution Inc.	0.1%
Sioux Lookout Hydro Inc.	0.1%
St. Thomas Energy Inc.	0.3%
Thunder Bay Hydro Electricity Distribution Inc.	0.9%
Tillsonburg Hydro Inc.	0.1%
Toronto Hydro-Electric System Limited	12.8%
Veridian Connections Inc.	2.4%
Wasaga Distribution Inc.	0.2%
Waterloo North Hydro Inc.	1.0%
Welland Hydro-Electric System Corp.	0.4%
Wellington North Power Inc.	0.1%
West Coast Huron Energy Inc.	0.1%
Westario Power Inc.	0.5%
Whitby Hydro Electric Corporation	0.9%
Woodstock Hydro Services Inc.	0.3%

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).

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.

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).

Free-ridership: the percentage of participants who would have implemented the program measure or practice in the absence of the program.

Incremental: the new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start'.

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

Net-to-Gross Ratio: The ratio of net savings to gross savings, which takes into account factors such as free-ridership and spillover

Net Energy Savings (MWh): energy savings attributable to conservation and demand management activities net of free-riders, etc.

Net Peak Demand Savings (MW): peak demand savings attributable to conservation and demand management activities net of free-riders, etc.

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

Realization Rate: A comparison of observed or measured (evaluated) information to original reported savings which is used to adjust the gross savings estimates.

Settlement Account: the grouping of demand response facilities (contributors) into one contractual agreement

Spillover: Reductions in energy consumption and/or demand caused by the presence of the energy efficiency program, beyond the program-related gross savings of the participants. There can be participant and/or non-participant spillover.

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

Table 11: Horizon Utilities Corporation Initiative and Program Level Gross Savings by Year

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period) 2011	2012	2013	2014	Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period) 2011	2012	2013	2014
Consumer Program									
Appliance Retirement**	Appliances	350	96	120		2,495,649	669,778	772,223	
Appliance Exchange**	Appliances	35	19	54		41,598	33,812	96,864	
HVAC Incentives	Equipment	2,798	2,183	1,997		5,121,925	3,743,882	3,426,318	
Conservation Instant Coupon Booklet	Items	44	9	19		735,082	53,604	276,622	
Bi-Annual Retailer Event	Items	61	66	46		1,087,497	1,181,405	664,698	
Retailer Co-op	Items	0	0	0		0	0	0	
Residential Demand Response	Devices	1,093	2,699	4,176		2,830	13,650	12,020	
Residential Demand Response (IHD)	Devices	0	0	0		0	0	0	
Residential New Construction	Homes	0	0	0		0	0	0	
Consumer Program Total		**4,381**	**5,072**	**6,413**		**9,484,581**	**5,696,131**	**5,248,744**	
Business Program									
Retrofit	Projects	1,192	2,049	4,030		6,499,364	11,576,745	22,364,696	
Direct Install Lighting	Projects	617	738	479		1,823,667	2,253,482	1,528,270	
Building Commissioning	Buildings	0	0	0		0	0	0	
New Construction	Buildings	0	1	11		0	3,158	38,576	
Energy Audit	Audits	0	16	107		0	75,529	586,485	
Small Commercial Demand Response	Devices	0	6	13		0	33	20	
Small Commercial Demand Response (IHD)	Devices	0	0	0		0	0	0	
Demand Response 3	Facilities	536	531	418		20,936	7,718	-1,735	
Business Program Total		**2,346**	**3,340**	**5,059**		**8,343,968**	**13,916,664**	**24,516,313**	
Industrial Program									
Process & System Upgrades	Projects	0	0	0		0	0	0	
Monitoring & Targeting	Projects	0	0	0		0	0	0	
Energy Manager	Projects	0	51	25		0	405,400	198,003	
Retrofit	Projects	94	0	0		524,802	0	0	
Demand Response 3	Facilities	3,498	6,445	13,579		205,346	155,311	329,778	
Industrial Program Total		**3,592**	**6,495**	**13,605**		**730,148**	**560,711**	**527,781**	
Home Assistance Program									
Home Assistance Program	Homes	0	19	808		0	287,021	4,634,362	
Home Assistance Program Total		**0**	**19**	**808**		**0**	**287,021**	**4,634,362**	
Aboriginal Program									
Home Assistance Program	Homes	0	0	0		0	0	0	
Direct Install Lighting	Projects	0	0	0		0	0	0	
Aboriginal Program Total		**0**	**0**	**0**		**0**	**0**	**0**	
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	5,876	0	0		33,885,712	0	0	
High Performance New Construction	Projects	485	293	0		2,489,177	1,164,328	0	
Toronto Comprehensive	Projects	0	0	0		0	0	0	
Multifamily Energy Efficiency Rebates	Projects	0	0	0		0	0	0	
LDC Custom Programs	Projects	0	0	0		0	0	0	
Pre-2011 Programs completed in 2011 Total		**6,361**	**293**	**0**		**36,374,889**	**1,164,328**	**0**	
Other									
Program Enabled Savings	Projects	0	0	0		0	0	0	
Time-of-Use Savings	Homes	0	0	0		0	0	0	
Other Total		**0**	**0**	**0**		**0**	**0**	**0**	
Adjustments to 2011 Verified Results		**0**	**826**	**0**		**0**	**5,441,801**	**0**	
Adjustments to 2012 Verified Results		**0**	**0**	**167**		**0**	**0**	**850,994**	
Energy Efficiency Total		**11,552**	**5,539**	**7,698**		**54,704,474**	**21,448,144**	**34,587,117**	
Demand Response Total		**5,128**	**9,681**	**18,186**		**229,113**	**176,712**	**340,083**	
Adjustments to Previous Year's Verified Results Total		**0**	**826**	**167**		**0**	**5,441,801**	**850,994**	
OPA-Contracted LDC Portfolio Total (inc. Adjustments)		**16,680**	**16,045**	**26,052**		**54,933,587**	**27,066,656**	**35,778,194**	

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

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

Adjustments to previous years' results shown in this table will not align to adjustments shown in Table 1 as the information presented above does not consider persistence of savings

Gross results are presented for informational purposes only and are not considered official 2013 Draft Verified Results

**Net results substituted for gross results due to inavailabilty of data

Table 12: Adjustments to Horizon Utilities Corporation Gross Verified Results due to Variances

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement	Appliances	0	0			0	0		
Appliance Exchange	Appliances	0	0			0	0		
HVAC Incentives	Equipment	-494	36			-911,621	62,386		
Conservation Instant Coupon Booklet	Items	1	0			10,349	0		
Bi-Annual Retailer Event	Items	5	0			95,962	0		
Retailer Co-op	Items	0	0			0	0		
Residential Demand Response	Devices	0	0			0	0		
Residential Demand Response (IHD)	Devices	0	0			0	0		
Residential New Construction	Homes	0	0			0	0		
Consumer Program Total		**-489**	**36**			**-805,310**	**62,386**		
Business Program									
Retrofit	Projects	158	131			813,113	788,609		
Direct Install Lighting	Projects	30	0			65,529	0		
Building Commissioning	Buildings	0	0			0	0		
New Construction	Buildings	1	0			3,158	0		
Energy Audit	Audits	52	0			251,763	0		
Small Commercial Demand Response	Devices	0	0			0	0		
Small Commercial Demand Response (IHD)	Devices	0	0			0	0		
Demand Response 3	Facilities	0	0			0	0		
Business Program Total		**241**	**131**			**1,133,563**	**788,609**		
Industrial Program									
Process & System Upgrades	Projects	0	0			0	0		
Monitoring & Targeting	Projects	0	0			0	0		
Energy Manager	Projects	0	0			0	0		
Retrofit	Projects	0	0			0	0		
Demand Response 3	Facilities	0	0			0	0		
Industrial Program Total		**0**	**0**			**0**	**0**		
Home Assistance Program									
Home Assistance Program	Homes	0	0			0	0		
Home Assistance Program Total		**0**	**0**			**0**	**0**		
Aboriginal Program									
Home Assistance Program	Homes	0	0			0	0		
Direct Install Lighting	Projects	0	0			0	0		
Aboriginal Program Total									
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	0	0			0	0		
High Performance New Construction	Projects	1,074	0			5,113,548	0		
Toronto Comprehensive	Projects	0	0			0	0		
Multifamily Energy Efficiency Rebates	Projects	0	0			0	0		
LDC Custom Programs	Projects	0	0			0	0		
Pre-2011 Programs completed in 2011 Total		**1,074**	**0**			**5,113,548**	**0**		
Other									
Program Enabled Savings	Projects	0	0			0	0		
Time-of-Use Savings	Homes	0	0			0	0		
Other Total		**0**	**0**			**0**	**0**		
Adjustments to 2011 Verified Results		**826**				**5,441,801**			
Adjustments to 2012 Verified Results			**167**				**850,994**		
Total Adjustments to Previous Year's Verified Results		**826**	**167**			**5,441,801**	**850,994**		

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

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

Gross results are presented for informational purposes only and are not considered official 2013 Draft Verified Results

Table 13: Province-Wide Initiatives and Program Level Gross Savings by Year

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement**	Appliances	6,750	2,011	3,012		45,971,627	13,424,518	17,760,133	
Appliance Exchange**	Appliances	719	556	1,723		873,531	974,621	3,072,972	
HVAC Incentives	Equipment	53,209	38,346	40,418		99,413,430	66,929,213	71,225,037	
Conservation Instant Coupon Booklet	Items	1,184	231	464		19,192,453	1,325,898	6,842,244	
Bi-Annual Retailer Event	Items	1,504	1,622	1,142		26,899,265	29,222,072	16,441,329	
Retailer Co-op	Items	0	0	0		3,917	0	0	
Residential Demand Response	Devices	10,390	49,038	95,869		23,597	359,408	263,461	
Residential Demand Response (IHD)	Devices	0	0	0		0	0	0	
Residential New Construction	Homes	0	1	26		1,813	4,884	259,826	
Consumer Program Total		**73,757**	**91,805**	**142,654**		**192,379,633**	**112,240,615**	**115,865,002**	
Business Program									
Retrofit	Projects	34,201	78,965	82,646		184,070,265	387,817,248	477,343,220	
Direct Install Lighting	Projects	22,155	20,469	19,807		65,777,197	68,896,046	68,140,249	
Building Commissioning	Buildings	0	0	0		0	0	0	
New Construction	Buildings	247	1,596	2,934		823,434	3,755,869	9,183,826	
Energy Audit	Audits	0	1,450	4,042		0	7,049,351	22,066,516	
Small Commercial Demand Response	Devices	55	187	773		131	1,068	1,297	
Small Commercial Demand Response (IHD)	Devices	0	0	0		0	0	0	
Demand Response 3	Facilities	21,390	19,389	26,338		633,421	281,823	294,024	
Business Program Total		**78,048**	**122,056**	**136,539**		**251,304,448**	**467,801,406**	**577,029,131**	
Industrial Program									
Process & System Upgrades	Projects	0	0	313		0	0	2,799,746	
Monitoring & Targeting	Projects	0	0	0		0	0	0	
Energy Manager	Projects	0	1,034	3,953		0	7,067,535	23,354,555	
Retrofit	Projects	6,372	0	0		38,412,408	0	0	
Demand Response 3	Facilities	176,180	74,056	165,132		4,243,958	1,784,712	4,245,451	
Industrial Program Total		**182,552**	**75,090**	**169,398**		**42,656,366**	**8,852,247**	**30,399,752**	
Home Assistance Program									
Home Assistance Program	Homes	4	1,777	2,361		56,119	5,524,230	20,987,275	
Home Assistance Program Total		**4**	**1,777**	**2,361**		**56,119**	**5,524,230**	**20,987,275**	
Aboriginal Program									
Home Assistance Program	Homes	0	0	267		0	0	1,609,393	
Direct Install Lighting	Projects	0	0	0		0	0	0	
Aboriginal Program Total		**0**	**0**	**267**		**0**	**0**	**1,609,393**	
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	40,418	0	0		223,956,390	0	0	
High Performance New Construction	Projects	10,197	6,501	772		52,371,183	23,803,888	3,522,240	
Toronto Comprehensive	Projects	33,467	0	0		174,070,574	0	0	
Multifamily Energy Efficiency Rebates	Projects	2,553	0	0		9,774,792	0	0	
LDC Custom Programs	Projects	534	0	0		649,140	0	0	
Pre-2011 Programs completed in 2011 Total		**87,169**	**6,501**	**772**		**460,822,079**	**23,803,888**	**3,522,240**	
Other									
Program Enabled Savings	Projects	0	2,177	2,979		0	525,011	1,160,045	
Time-of-Use Savings	Homes	0	0	0		0	0	0	
Other Total		**0**	**2,177**	**2,979**		**0**	**525,011**	**1,160,045**	
Adjustments to 2011 Verified Results			**13,266**	**635**			**48,705,294**	**1,694,293**	
Adjustments to 2012 Verified Results				**7,840**				**47,147,540**	
Energy Efficiency Total		**213,515**	**156,735**	**166,859**		**942,317,539**	**616,320,385**	**745,768,605**	
Demand Response Total		**208,015**	**142,670**	**288,112**		**4,901,107**	**2,427,011**	**4,804,233**	
Adjustments to Previous Year's Verified Results Total		**0**	**13,266**	**8,474**		**0**	**48,705,294**	**48,841,832**	
OPA-Contracted LDC Portfolio Total (inc. Adjustments)		**421,530**	**312,671**	**463,445**		**947,218,646**	**667,452,690**	**799,414,670**	

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

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is

Adjustments to previous years' results shown in this table will not align to adjustments shown in Table 1 as the information presented above does not consider persistence of savings

Gross results are presented for informational purposes only and are not considered official 2013 Draft Verified Results

**Net results substituted for gross results due to inavailabilty of data

Table 14: Adjustments to **Province-Wide** Gross Verified Results due to Variances

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement	Appliances	0	0			0	0		
Appliance Exchange	Appliances	0	0			0	0		
HVAC Incentives	Equipment	-8,762	1,036			-16,245,279	1,854,833		
Conservation Instant Coupon Booklet	Items	15	0			255,975	0		
Bi-Annual Retailer Event	Items	117	0			2,373,616	0		
Retailer Co-op	Items	0	0			0	0		
Residential Demand Response	Devices	0	0			0	0		
Residential Demand Response (IHD)	Devices	0	0			0	0		
Residential New Construction	Homes	0	0			328,256	0		
Consumer Program Total		**-8,630**	**1,036**			**-13,287,430**	**1,854,833**		
Business Program									
Retrofit	Projects	4,504	5,876			22,046,931	38,475,976		
Direct Install Lighting	Projects	541	217			1,346,618	781,858		
Building Commissioning	Buildings	0	0			0	0		
New Construction	Buildings	3,243	0			11,323,593	0		
Energy Audit	Audits	481	0			2,341,392	0		
Small Commercial Demand Response	Devices	0	0			0	0		
Small Commercial Demand Response (IHD)	Devices	0	0			0	0		
Demand Response 3	Facilities	0	0			0	0		
Business Program Total		**8,769**	**6,092**			**37,058,534**	**39,257,834**		
Industrial Program									
Process & System Upgrades	Projects	0	0			0	0		
Monitoring & Targeting	Projects	0	0			0	0		
Energy Manager	Projects	0	0			0	0		
Retrofit	Projects	0	0			0	0		
Demand Response 3	Facilities	0	0			0	0		
Industrial Program Total		**0**	**0**			**0**	**0**		
Home Assistance Program									
Home Assistance Program	Homes	0	0			0	0		
Home Assistance Program Total		**0**	**0**			**0**	**0**		
Aboriginal Program									
Home Assistance Program	Homes	0	0			0	0		
Direct Install Lighting	Projects	0	0			0	0		
Aboriginal Program Total		**0**	**0**			**0**	**0**		
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	266	0			1,049,108	0		
High Performance New Construction	Projects	12,872	0			23,905,663	0		
Toronto Comprehensive	Projects	0	0			0	0		
Multifamily Energy Efficiency Rebates	Projects	0	0			0	0		
LDC Custom Programs	Projects	0	0			0	0		
Pre-2011 Programs completed in 2011 Total		**13,137**	**0**			**24,954,771**	**0**		
Other									
Program Enabled Savings	Projects	624	711			1,673,712	6,034,873		
Time-of-Use Savings	Homes	0	0			0	0		
Other Total		**624**	**711**			**1,673,712**	**6,034,873**		
Adjustments to 2011 Verified Results		**13,900**				**50,399,586**			
Adjustments to 2012 Verified Results			**7,840**				**47,147,540**		
Adjustments to Previous Year's Verified Results Total		**13,900**	**7,840**			**50,399,586**	**47,147,540**		

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

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

Gross results are presented for informational purposes only and are not considered official 2013 Draft Verified Results

3.0 –VECC -76TC

Reference: E9/T5/S1, Tables 9-19 and 9-20

a) Please explain why there are no CDM savings attributed to the LU classes for 2015-2019 when (per Exhibit 9) the LU class contributed to the CDM savings in 2011 and 2012.

b) With respect to Tables 9-19 and 9-20 what are the actual GWh savings associated with the CDM results attributed to the GS>50 and Large User classes by the OPA?

Response:

a) Horizon Utilities did not include CDM savings attributed to the Large Use classes for 2015-2019 due to the fact that there is a level of unpredictability and lack of confirmed initiatives for this specific rate class.

Projects for this customer class require long lead times and at this time Horizon Utilities does not have any specific projects that are in the queue.

b) The GWh savings associated with the CDM results attributed to the GS > 50 kW and Large User classes by the OPA are as follows:

For 2011:
GS>50 12,409,619 kWhs
Large User 11,743,632 kWhs

For 2012:
GS>50 10,739,416 kWhs

In Horizon Utilities’ response to 9-Staff-47, the updated charts from the OPA issued in Q1 2014 were used.

These GWh savings are not shown in Tables 9-19 and 9-20 as only the demand (kW) savings are used for the calculation of the LRAMVA. The energy savings are used for Horizon Utilities' CDM targets.

3.0 –VECC -77TC

Reference: 3-VECC-17 d)

a) Please clarify what will be the basis for the 2014 LRAM calculation:

i. How will the actual savings for 2014 be calculated (i.e., based on what years' program results)? What, if any, of these savings are currently known?

ii. What is the threshold value that will be used for true-up purposes?

Response:

i) Horizon Utilities will calculate any difference between actual and forecast savings consistent with the methodology used to calculate the 2011 and 2012 LRAMVA amounts. Horizon Utilities will calculate any difference between actual and forecast savings for the programs implemented in 2013 and 2014, when the verified results are received from the OPA for those years. Horizon Utilities received the OPA Report preliminary report for the 2013 savings on August 1, 2014; tables 9-19 and 9-20 were not updated at the time for the response to the interrogatory.

ii) Horizon Utilities is not proposing any thresholds for 2015 – 2019 for the LRAMVA accounts. Horizon Utilities will follow the Board's guidelines as set out in Section 13.4 of the Guidelines for Electricity Distributors Conservation and Demand Management Guidelines (EB 2012-0003) for the disposition of the LRAMVA. In the Guideline, Section 13.4 Disposition of the LRAMVA states: "*At a minimum, distributors must apply for disposition of the balance in the LRAMVA the time of their Cost of Service rate applications. Distributors may apply for the disposition of the balance in the LRAMVA on an annual basis during the IRM filing if the applicant feels that the amount is significant. The LRAMVA shall not be included in the pre-set disposition threshold calculation in determining materiality for disposition for Group 1 accounts as per the July 31, 2009 Report of the Board: Electricity Distributors' Deferral and Variance Account Initiative EB-2008-0046.*" Horizon Utilities has interpreted the question to relate to thresholds for disposition purposes. Horizon Utilities is in the Board's hands regarding a decision on the disposition threshold.

3.0 –VECC -78TC

Reference: 3-VECC-17 e)

3-VECC-18 d)

a) The original question was with regard to the determination of the manual CDM adjustment included in the 2014 load forecast (per Table 3.5) – and not the LRAM threshold as addressed in the response. Please respond to the question originally posed.

b) Please reconcile the 2014 load forecast adjustment of 28.142 GWH per Table 3.5 with the value of 7.035 GWh as shown in VECC 18 d).

Response:

a) Subsequent to the submission of the Interrogatory Responses, Horizon Utilities reviewed the information provided for 3-VECC-19, 3-VECC-20, and 3-VECC-21. It determined that the monthly and cumulative CDM adjustments were lagged an additional four months from January 2014 and began on May 2014Horizon Utilities manual CDM adjustment included in the 2014 load forecast should have read 15,243,583 instead of the 28,142,000. This is the corrected cumulative monthly impact of the Residential, GS < 50 kW and GS > 50 kW CDM adjustments to the 2014 load forecast before the update to Table 3-5 as filed in 3-VECC-75TC. In addition, Horizon Utilities has provided an update to Appendix 2-I for its 2014 CDM Adjustment based on the OPA report of the 2013 preliminary results in its response to 3-VECC-75 which outlines the new 2014 CDM Adjustment amount included in the load forecast.

b) Horizon Utilities has provided an update to the table provided in VECC 18 d) which addresses the reconciliation issues in Table 1. Horizon Utilities has provided in Table 2 below, a revised version of what is included each year for the CDM savings per the update to Appendix 2-I.

Table 1: Update to VECC 18 d)

CDM Program Year	Forecast Year - Total CDM Savings Assumed					
	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
2014 Bridge Year	15,243,583	28,142,000	28,142,000	28,142,000	28,142,000	28,142,000
2015 Test Year		10,581,028	19,534,205	19,534,205	19,534,205	19,534,205
2016 Test Year			10,361,753	19,205,046	19,205,046	19,205,046
2017 Test Year				10,286,097	19,129,390	19,129,390
2018 Test Year					10,286,097	19,129,390
2019 Test Year						10,286,097
Total	15,243,583	38,723,028	58,037,958	77,167,348	96,296,738	115,426,128

Table 2: Update to VECC 18 d) based on updated Appendix 2-I

CDM Program Year	Forecast Year - Total CDM Savings Assumed					
	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
2014 Bridge Year	21,763,566	40,178,891	40,178,891	40,178,891	40,178,891	40,178,891
2015 Test Year		10,581,027	19,534,205	19,534,205	19,534,205	19,534,205
2016 Test Year			10,361,753	19,205,046	19,205,046	19,205,046
2017 Test Year				10,286,097	19,129,390	19,129,390
2018 Test Year					10,286,097	19,129,390
2019 Test Year						10,286,097
Total	21,763,566	50,759,918	70,074,849	89,204,239	108,333,629	127,463,019

3.0 –VECC -79TC

Reference: 3-VECC-18

a) Please explain more fully how the forecast CDM savings from 2015-2019 programs were developed.

b) Please explain how the first year's impacts for the 2014-2019 programs were established (i.e. For 2014 - 7.035,500 kWh versus 28,142,000 kWh for subsequent years and for 2015 – 3,710,968 kWh in the first year versus 19,534,205 in subsequent years).

c) What are the LRAMVA thresholds that Horizon is proposing for 2015-2019? Please provide a kWh breakdown by customer class.

Response:

a) The forecasted CDM savings from 2015 – 2019 is a conservative estimate solely based on the performance of current OPA Province-Wide programs using 2011 – 2012 verified CDM savings and Q3 2013 preliminary results and Q4 2013 forecasted savings, which was the best available information at the time that Horizon Utilities filed its Application. The estimate reflects expected CDM results by customer class, excluding the LU (1) and LU (2) customer classes for the period 2015 - 2019. The 2015 – 2019 estimated CDM results provided does not factor the impact of energy efficiency gains from changes to codes and standards. The estimates reflected the assumption that declining market potential would occur in the years 2015 – 2019 due to the maturity of the Province-Wide programs currently being offered. At the time of filing the Application, Horizon Utilities was not allocated a new CDM target for the 2015 – 2019 rate years nor was there evidence on what OPA Province-Wide programs would persist into rate years 2015 – 2019.

b) Please refer to Horizon Utilities' response to 3-VECC-78TC a).

c) Horizon Utilities is not proposing any thresholds for 2015 – 2019. Horizon Utilities will follow the Board's guidelines as set out in Section 13.4 of the Guidelines for Electricity Distributors

Conservation and Demand Management (EB 2012-0003) for the disposition of the LRAMVA.

> ***"13.4 Disposition of the LRAMVA:*** *At a minimum, distributors must apply for disposition of the balance in the LRAMVA the time of their Cost of Service rate applications. Distributors may apply for the disposition of the balance in the LRAMVA on an annual basis during the IRM filing if the applicant feels that the amount is significant. The LRAMVA shall not be included in the pre-set disposition threshold calculation in determining materiality for disposition for Group 1 accounts as per the July 31, 2009 Report of the Board: Electricity Distributors' Deferral and Variance Account Initiative EB-2008-0046."*

3.0 –VECC -80TC

Reference: 3-VECC-26 b)

a) Where applicable please also provide the actual number of connections by class as of June 2014

Response:

Horizon Utilities has provided the actual number of connections by class as of June 30, 2014 in the table below.

Customer Class	Billing Determinant	June 30, 2014	As Filed	Variance
USL	Connection	3,043	3,048	(5)
Sentinel Lighting	Connection	408	407	1
Street Lighting	Device	52,420	52,413	7
TOTAL		55,871	55,868	3

4.0 -VECC -81TC

Reference: 4.2-VECC-34

a) Please provide a corresponding table showing forecast capital expenditures for storm related damage. Please also show the corresponding actual capital expenditures for 2011 through 2013

b) The forecast OM&A (1,350k) appear to be almost the actual year experience for 2012 and 2013. Please explain why?

Response:

a) Horizon Utilities has not separately budgeted capital expenditures for major storms; those costs are part of the overall reactive capital budget as stated in response to Interrogatory VECC 34 a). Actual capital expenditures for major storms in 2011-2013 are provided in Exhibit 4, Tab 3, Schedule 3, page 64, Table 4-40 and reproduced in Table 1 below:

Table 1: Actual capital expenditures for major storms in 2011-2013

	2011	2012	2013
Capital Expenditures (Actual)	$1,075,340	$511,501	$818,602

b) In response to Interrogatory VECC 34 b), Horizon Utilities has indicated that the OM&A cost budgeted for three major storms in 2014 is $1,250,000 and not $1,350,000 as cited in part b) of this question. The total of 2012 plus 2013 actual costs reflected four major storms for a total cost of $1,438,000 as shown in Exhibit 4, Tab 3, Schedule 3, page 64, Table 4-40. The 2014 forecast is based on three major storms while the 2012 and 2013 experience was based on two major storms each year.

4.0 -VECC -82TC

Reference: 4.2-VECC-43

a) The interrogatory incorrectly states the doubling of PC Services is during the rate plan period. It will more than double as compared to actual (and Board approved) expenditures in 2011. What is the reason(s) for the large increase. Please quantify how much of the increase, if any, is related to smart meter related IT investments

Response:

The following items contributed to incremental operating expenses in the IST sub-department PC Services:

- Increases in Salaries and Benefits comprised of: annual salary increases; creation of a Supervisor, IST Service Desk position to address IST management capacity issues resulting from growth of the IT infrastructure as outlined in Exhibit 4, Table 3, Schedule 3 page 31, Line 5, and the full complement of staff planned in 2014 to 2019. All planned FTE positions and unplanned vacancies were filled in 2013.
- Incremental annual Internet Services (telecommunications) of $183,355 for expansion of network bandwidth to support business requirements as outlined in Exhibit 4,Tab 2, Schedule 2, page 13, line 21.
- Incremental annual hardware and software maintenance of $475,032 from 2011 to 2015 to support new business requirements as outlined in Exhibit 4, Tab 2, Schedule 2, page 11, Line 21.
- Incremental annual hardware and software maintenance to future growth of the server and storage area network from 2015 to 2019 based on historical experience of annual data growth rates in excess of 30% per year as outlined in the response to 1-SEC-61TC.
- Increased annual hardware and software maintenance of $48,000 to support the planned implementation of Enterprise Unified Communications capabilities in 2015 to drive increased staff productivity of $280,000 per year as outlined in Exhibit 4, Tab 3, Schedule 3, page 34.

Horizon Utilities is unable to segregate the PC Services cost increases related directly to smart meters. Operating expenses in PC Services function are not managed by application. The Horizon Utilities’ IT infrastructure is shared by over 120 virtual servers and over 200 applications. Consolidating implementation and management of the IT infrastructure (servers, storage area network, and telecommunications) including the infrastructure components related to smart meters simplifies the infrastructure reducing the staff effort to manage the environment.

4.0 -VECC -83TC

Reference: 4.2-VECC-44

a) Please provide the forecast EDA fees for 2015 through 2019?

Response:

Horizon Utilities is providing the forecast for 2015 – 2019.

2015 Forecast	2016	2017	2018	2019
$115,000	$116,725	$118,476	$120,253	$122,057

7.0 – VECC –84TC

Reference: 8-Staff-33

a) Please confirm that a major reason for the decrease in bills for the LU(2) class in 2015 is the proposed reduction in the class' revenue to cost ratio from 949.12% to 115%.

b) Please confirm that status quo ratio for the LU(2) class falls to 74.86% in 2016, primarily due to capital work in that year on the transformer dedicated to the serving this class.

c) Please confirm that increasing the LU(2) class' 2016 revenue to cost to 85% is one of the main reasons for the rate impacts reported for the class in 2016.

d) What revenue to cost ratio for 2015 would lead to a 2016 status quo LU(2) revenue to cost ratio of 85%?

e) What revenue to cost ratio for 2015 would lead to a 2016 status quo LU(2) revenue to cost ratio of 115%?

f) Assuming the rates for 2016 were set based on a revenue to cost ratio of 115% - what would be the resulting 2017 status quo LU(2) class revenue to cost ratio?

Response:

a) Yes – reducing the LU(2) ratio to within the Board Approved Range does decrease the bill impacts for the LU (2) class.
b) Yes – the revenue to cost ratio decreases in 2016 for the LU (2) class due directly allocated capital work.
c) Yes – increasing the Revenue to cost ratio for the LU (2) class to 85% is one of the main reasons for the rate impacts reported for the LU (2) class.
d) A revenue to cost ratio of 130.61% in 2015 leads to a status quo revenue to cost ratio of 85% in 2016 for the LU (2) class.
e) A revenue to cost ratio of 176.90% in 2015 leads to a status quo revenue to cost ratio of 115% in 2016 for the LU (2) class.

f) Assuming the rates for 2016 were based on a revenue to cost ratio of 115%, with no change to the 2015 rates, the resulting status quo 2017 ratio would be 88.96%. Assuming the rates for 2016 were based on a revenue to cost ratio of 115%, and assuming that 2015 revenues were set using the criteria stipulated in part e, the resulting status quo 2017 ratio would be 65.85%.

7.0 – VECC –85TC

Reference: C of H – 3

a) Please clarify whether, based on Horizon's definition, a serial connection of streetlights is considered to be a "daisy chain" and treated as one "connection" if the inter-connecting conductor joining the devices is owned by Horizon.

b) If yes and such circumstances exist in Horizon's service area, how would treating each of the devices (i.e. streetlights) in such situations as a separate connection impact the 1.3141:1 device to connection ratio used in the Cost Allocation?

Response:

a) Horizon Utilities confirms that serial connections are considered one daisy chain and are treated as one connection.

b) If each street lighting device were treated as one connection, the device to connection ratio would be 1:1.

7.0 –VECC -86TC

Reference: 7-Energy Probe-53

a) Please indicate where/how the fact that the IESO undertakes the data verification process for smart meter data (i.e. Residential and GS<50 customers) whereas Horizon must perform this activity itself for other metered customer classes is taken into account in the development of the Billing and Collecting weighting factors.

Response:

The weighting factor for services is computed based on the number of bills and does not adjust for classes where the IESO undertakes the data verification process.

7.0 –VECC -87TC

Reference: 7-SEC-46

7-SEC-49

7-VECC-56

a) What is the basis for Horizon picking four years as the minimum amount of Smart Meter data required in order to determine weather-normalized load profiles?

b) With respect to the response to SEC-49, are saturation studies required once sufficient Smart Meter data is available? If so, why?

Response:

a) To develop load profiles, 10 years of monthly energy data is preferred to get reliable results. Horizon Utilities identified 4 years as a bare minimum amount of data based on judgment. As stated previously, 10 years would be preferable. Horizon Utilities wishes to offer a further point of clarification that Smart Meter data is archived off-line and it would be a significant expense to procure a system or the processing power to analyze 3+ years of hourly Smart Meter reads for 240,000 customers. Horizon Utilities would require servers, storage, database software, business analytics software, incremental data backup storage capacity, consulting support, and incremental FTE to develop and support a Smart Meter data analytics environment. The initial investment could be between $400K to $1,000,000 in CAPEX plus annual operating costs for consulting, FTE, and hardware/software maintenance.

b) No, saturation studies would not be required as they are only required for a bottom-up development of load profiles. Saturation studies are integral to developing estimate load profiles in the absence of actual consumption info (i.e., smart meter data). The bottom-up approach provides weather normalized demand by definition, so it would not be required if Horizon Utilities had enough smart meter data to produce a reliable weather normalized load profile based on actual historical usage.

7.0 –VECC -88TC

Reference: 7-SEC-50

Preamble: The Application indicates (Elenchus Study, page 8) that the load profiles for the LU(1) and LU(2) classes were based on 2012 actual interval data.

a) The 1NCP, 4NCP and 12 NCP values for LU(1) and LU(2) sum to the aggregated LU class value in each case, suggesting that the non-coincident peaks for both sub-classes (i.e. LU(1) and (LU2)) occurred at the same time in all twelve months of 2012. Please confirm that this is the case and provide the supporting data.

Response:

The column labelled 2015 Large Use, provided in response to Interrogatory 7-SEC-50 was in fact labelled in error. It was a total of allocators to all Large Use (1) and Large Use (2) customers to facilitate a comparison of the share of costs allocated to Large Use customers in 2011 on the basis of demand allocators to all customers which fit the 2011 Large Use definition, but based on 2015 methodology. Therefore, it was a straight sum of 2015 Large Use (1) and 2015 Large Use (2). However, if all 2015 Large Use (1) and Large Use (2) customers were taken a single class, the NCP allocators would indeed be different. The table below reproduces the table from Interrogatory SEC-50, using the idea of 2015 Large Use as a single class.

Since the understanding contained in the question is not confirmed, supporting data is understood to be unnecessary.

Table 1: LU (1) and LU (2) Peak Data

	2011 Large Use		2015 Large Use (1)		2015 Large Use (2)		2015 Large Use	
	kW	%	kW	%	kW	%	kW	%
1 CP	175,745	19.2	31,342	3.3	128,289	13.4	159,631	16.7
4 CP	673,366	19.4	129,553	3.5	565,812	15.5	695,365	19.0
12 CP	2,138,999	22.8	415,122	4.2	1,654,061	16.8	2,069,184	21.0
1 NCP	206,451	19.9	40,167	3.6	167,297	15.1	204,340	18.6
4 NCP	815,628	20.6	159,122	3.8	656,503	15.6	797,070	19.2
12 NCP	2,377,788	22.2	471,779	4.2	1,871,544	16.6	2,295,248	20.6

7.0 –VECC -89TC

Reference: 7-VECC-56 d) & e)

a) Please confirm that the value reported in the referenced cells J36 and J37 are Gross Book values and not depreciation.

b) Please confirm that the $47,118 in depreciation allocated to LU(2) in 2015 (per Sheet O1) consists of:

i. $11,893 for Buildings

ii. $18,530 for Meters

iii. $16,694 for General Plant

Note: This can be seen from Sheet O7.

c) If part (b) is confirmed, please provide a response to VECC-56, part (e).

Response:

a) The values reported in J36 and J37 are the Net Book value, not depreciation.

b) Horizon Utilities confirms these amounts.

c) Horizon Utilities has reviewed the Cost Allocation model again and has directly allocated the following depreciation amounts to the LU (2) class for 2015 through 2019 by year: 2015: $10,111, 2016: $70,024, 2017-2019: $129,937 (per year).

8.0 –VECC -90TC

Reference: 8-VECC-59 b)

a) Please note the original question asked how the “cost” of the TOA was recover – not which customers received the discount. Please respond to the original question.

Response:

a) The cost is recovered from all GS > 50 kW customers.

8.0 –VECC -91TC

Reference: 8-SIA-33

8-VECC-61

a) How much does it cost Horizon to process a payment received in cash or by cheque versus the estimated cost of $6.70 transaction for a payment received via credit card/Paymentus (including the $5.95 fee) – per VECC 61 c)?

Response:

Horizon Utilities estimates the cost to process payments, regardless of methodology, are approximately $0.75 per transaction.

8.0 –VECC -92TC

Reference: 8-VECC-62

a) Please explain why the GS>50 billing kW used to derive the 2015 rates in Table 8-14 (4,510,548) differs from that the forecast values in Table 3-29 and Table 8-35 (5,114,245).

Response:

The kW for the GS > 50 kW class are incorrect. Horizon Utilities provides revised versions of Table 8-14, 8-15, 8-16, 8-17, and 8-18 below.

Revised Table 8-14

Rate Class	Base Revenue Requirement	Fixed Revenue Proportion	Fixed Revenue Amount	Transformer Allowance	2015 Annualized kWh/kW	Proposed Fixed Distribution Rates
	A	B	C=A*B		D	E=C/D
Residential	$ 69,461,355	37.59%	$ 26,107,359		1,617,715,605	$ 0.0161
GS < 50 kW	$ 15,412,682	40.70%	$ 6,272,403		586,002,830	$ 0.0107
GS >50 to 4999 kW	$ 21,400,734	53.55%	$ 11,460,577	$ 1,533,896	5,114,245	$ 2.5408
Standby	$ 739,292	100.00%	$ 739,292		0	$ 2.5407
LU (1)	$ 2,157,451	30.56%	$ 659,241		626,465	$ 1.0523
LU (2)	$ 480,086	69.85%	$ 335,326		1,884,533	$ 0.1779
Sentinel Lights	$ 46,725	41.42%	$ 19,356		1,241	$ 15.5994
Street Lighting	$ 2,740,679	31.77%	$ 870,799		110,006	$ 7.9159
Unmetered and Scattere	$ 517,021	32.68%	$ 168,954		11,397,660	$ 0.0148
TOTAL	**$ 112,956,026**		**$ 46,633,305**			

Revised Table 8-15

Rate Class	Base Revenue Requirement	Fixed Revenue Proportion	Fixed Revenue Amount		2016 Annualized kWh/kW	Proposed Fixed Distribution Rates
	A	B	C=A*B		D	E=C/D
Residential	$ 72,903,466	37.32%	$ 27,205,971		1,615,569,770	$ 0.0168
GS < 50 kW	$ 16,160,545	40.59%	$ 6,559,477		585,648,636	$ 0.0112
GS >50 to 4999 kW	$ 22,482,464	53.03%	$ 11,923,119	$ 1,533,896	5,085,745	$ 2.6460
Standby	$ 794,058	100.00%	$ 794,058		0	$ 2.6456
LU (1)	$ 2,269,990	30.97%	$ 702,932		638,647	$ 1.1007
LU (2)	$ 580,573	70.25%	$ 407,834		1,921,178	$ 0.2123
Sentinel Lights	$ 47,588	40.67%	$ 19,357		1,185	$ 16.3289
Street Lighting	$ 2,867,294	31.77%	$ 911,037		109,948	$ 8.2861
Unmetered and Scattere	$ 522,521	32.27%	$ 168,614		11,174,331	$ 0.0151
TOTAL	**$ 118,628,501**		**$ 48,692,398**			

Revised Table 8-16

Rate Class	Base Revenue Requirement	Fixed Revenue Proportion	Fixed Revenue Amount	Transformer Allowance	2017 Annualized kWh/kW	Proposed Fixed Distribution Rates
	A	B	C=A*B		D	E=C/D
Residential	$ 74,595,365	36.97%	$ 27,576,597		1,608,117,860	$ 0.0171
GS < 50 kW	$ 16,549,987	40.39%	$ 6,685,255		583,142,939	$ 0.0115
GS >50 to 4999 kW	$ 23,137,026	52.63%	$ 12,176,015	$ 1,533,896	5,068,149	$ 2.7051
Standby	$ 836,832	100.00%	$ 836,832		0	$ 2.7056
LU (1)	$ 2,331,533	31.39%	$ 731,980		651,503	$ 1.1235
LU (2)	$ 782,837	70.66%	$ 553,179		1,959,852	$ 0.2823
Sentinel Lights	$ 47,446	39.99%	$ 18,975		1,135	$ 16.7141
Street Lighting	$ 2,933,368	31.77%	$ 932,033		109,890	$ 8.4815
Unmetered and Scattere	$ 529,049	31.90%	$ 168,789		10,951,001	$ 0.0154
TOTAL	**$ 121,743,444**		**$ 49,679,654**			

Revised Table 8-17

Rate Class	Base Revenue Requirement	Fixed Revenue Proportion	Fixed Revenue Amount	Transformer Allowance	2018 Annualized kWh/kW	Proposed Fixed Distribution Rates
	A	B	C=A*B		D	E=C/D
Residential	$ 75,944,135	36.66%	$ 27,837,499		1,604,991,612	$ 0.0173
GS < 50 kW	$ 16,829,093	40.31%	$ 6,783,482		581,558,617	$ 0.0117
GS >50 to 4999 kW	$ 23,538,584	52.17%	$ 12,280,094	$ 1,533,896	5,042,608	$ 2.7395
Standby	$ 872,552	100.00%	$ 872,552		0	$ 2.7399
LU (1)	$ 2,378,306	31.78%	$ 755,899		663,329	$ 1.1396
LU (2)	$ 804,863	71.04%	$ 571,760		1,995,427	$ 0.2865
Sentinel Lights	$ 46,828	39.22%	$ 18,365		1,083	$ 16.9648
Street Lighting	$ 2,975,756	31.77%	$ 945,506		109,831	$ 8.6087
Unmetered and Scattere	$ 530,200	31.50%	$ 167,007		10,727,671	$ 0.0156
TOTAL	**$ 123,920,317**		**$ 50,232,163**			

Revised Table 8-18

Rate Class	Base Revenue Requirement	Fixed Revenue Proportion	Fixed Revenue Amount	Transformer Allowance	2019 Annualized kWh/kW	Proposed Fixed Distribution Rates
	A	B	C=A*B		D	E=C/D
Residential	$ 78,365,794	36.35%	$ 28,487,790		1,600,739,130	$ 0.0178
GS < 50 kW	$ 17,351,714	40.22%	$ 6,979,597		579,899,038	$ 0.0120
GS >50 to 4999 kW	$ 24,297,713	51.70%	$ 12,562,078	$ 1,533,896	5,016,885	$ 2.8097
Standby	$ 920,444	100.00%	$ 920,444		0	$ 2.8095
LU (1)	$ 2,460,571	32.17%	$ 791,587		675,234	$ 1.1723
LU (2)	$ 838,452	71.40%	$ 598,656		2,031,238	$ 0.2947
Sentinel Lights	$ 46,806	38.40%	$ 17,972		1,030	$ 17.4518
Street Lighting	$ 3,059,543	31.77%	$ 972,128		109,773	$ 8.8558
Unmetered and Scattere	$ 540,863	31.15%	$ 168,477		10,504,342	$ 0.0160
TOTAL	**$ 127,881,899**		**$ 51,498,730**			