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Ontario

BY E-MAIL

December 4, 2015

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

Dear Ms. Walli:

Re: Halton Hills Hydro Inc.
Application for Rates
Ontario Energy Board File Number EB-2015-0074

In accordance with Procedural Order No. 1, please find attached OEB staff's interrogatories in the above noted proceeding. Halton Hills Hydro Inc. and all intervenors have been copied on this filing.

Halton Hills Hydro Inc.'s responses to interrogatories are due by January 18, 2016.

Yours truly,

Original signed by

Violet Binette
Project Advisor, Applications

Attach

Ontario Energy Board (OEB) Staff Interrogatories
Halton Hills Hydro Inc. (HHHI)
2016 Cost of Service - EB-2015-0074
December 4, 2015

GENERAL

1-Staff-1
Updated Revenue Requirement Work Form

Upon completing all interrogatories from OEB staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that HHHI wishes to make to the amounts in the populated version of the RRWF filed in the initial applications. Entries for changes and adjustments should be included in the middle column on sheet 3 Data_Input_Sheet. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note. Such notes should be documented on Sheet 10 Tracking Sheet, and may also be included on other sheets in the RRWF to assist understanding of changes.

1-Staff-2
Updated Appendix 2-W, Bill Impacts

Upon completing all interrogatories from OEB staff and intervenors, please provide an updated Appendix 2-W for all classes at the typical consumption / demand levels (e.g. 800 kWh for residential, 2,000 kWh for GS<50, etc.).

The bill impacts should reflect the regulatory charges set out in the Decision on Regulatory Charges for 2016, EB-2015-0294, issued on November 19, 2015.

RATE BASE AND CAPITAL EXPENDITURE

2-Staff-3
Ref: Exh 2 pages 28 and 33 – Capital Contributions
Ref: Exh 1 Appendix 1-D Audited Financial Statements

The application states that 2012 actual contributed capital was lower than 2012 OEB approved by $1,110,139. Table 2-25 indicates that 2012 actual contributions were a cost of $39,153.

a) Please explain the $39,153 contribution that was a cost, i.e. a negative contribution, in 2012.
b) OEB staff notes that the audited financial statements for both 2012 and 2013 show that 2012 actual capital contributions were $1,085,377. OEB staff also notes that the capital contributions in Table 2-25 for 2013 and 2014 are consistent with the audited

financial statements. Please explain the difference between the audited financial statements and the $39,153 cost noted in the application.

2-Staff-4
Ref: Exh 2 page 38 – Working Capital Allowance

This Application has been prepared using the default Working Capital Allowance for the 2016 Rate Year of 7.5%. The application was filed on August 28, 2015 and re-filed on October 2, 2015. It states that HHHI is still in the process of assessing the impact of the new OEB policy, and reserves the right to subsequently submit evidence in support of an HHHI-specific working capital allowance, supported by a lead-lag study.

Please confirm whether or not HHHI has initiated a lead-lag study following the filing of its application and, if so, when the HHHI-specific working capital allowance proposal will be filed.

2-Staff-5
Ref: Exh 2 page 40 – Working Capital Allowance

The cost of power was based on data in the OEB report issued on April 20, 2015. Please update the working capital cost of power calculation for 2016 using the OEB's RPP Price Report for the Regulated Price Plan issued on October 15, 2015.

2-Staff-6
Ref: Exh 2 page 90 – Service Quality and Reliability Indicators

HHHI provided reliability statistics for 2010 to 2014.

Index Including Outages Caused by Loss of Supply						5 Year Average	OEB Target
	2010	2011	2012	2013	2014		
SAIDI	1.780	1.550	1.530	2.510	1.250	**1.724**	1.23 - 1.78
SAIFI	2.750	1.670	1.900	1.990	1.610	**1.984**	1.22 - 2.75
Index Excluding Outages Caused by Loss of Supply							
SAIDI	1.780	1.380	1.230	2.080	1.210	**1.536**	
SAIFI	2.750	1.490	1.340	1.480	1.470	**1.706**	

a) Please confirm data in the above table and please confirm that HHHI's target is the 5 year average 2010-2014.
b) HHHI reports that 2013 reliability was affected by storms in April, July and December of 2013. Otherwise, there was a trend of improvement. Please exclude 2013 and calculate a 4 year average.

2-Staff-7
Ref: Exh 2, Appendix 2-A - Distribution System Plan page 12

Transformer Stock Code:	OH015						Analysis Date:		
Transformer Type:	Pole								
Transformer Rating Info:	1-Phase, 100 kVA, 4160GrdY/2400 - 347/600 V								
Manufacturer, Bid Price & Guaranteed Performance				Analysis of Transformer Ownership Costs				Other Considerations	
Manufacturer	Unit Price (P)	No-load (core) losses, watts (N)	Load (winding) losses, watts (L)	Present Value of No-load Losses	Present Value of Load Losses	Total Cost of Losses	Total Transformer Ownership Costs [(Col 2) + (Col 7)]	Delivery, weeks A.R.O.	F.O.B. Location
(Col 1)	(Col 2)	(Col 3)	(Col 4)	(Col 5_	(Col 6)	(Col 7)	(Col 8)	(Col 9)	(Col 10)
Manufacturer	$3,650.00	190	610	$1,577.00	$2,501.00	$4,078.00	$7,728.00	12	Halton Hills Hydro
Manufacturer	$4,090.00	145	756	$1,203.50	$3,099.60	$4,303.10	$8,393.10	12	Halton Hills Hydro
Manufacturer	$3,895.00	192	840	$1,593.60	$3,444.00	$5,037.60	$8,932.60	8	Halton Hills Hydro
Manufacturer	$3,465.00	217	1272	$1,801.10	$5,215.20	$7,016.30	$10,481.30	14	Halton Hills Hydro
Manufacturer	$5,399.21	255	912	$2,116.50	$3,739.20	$5,855.70	$11,254.91	16	Halton Hills Hydro
Manufacturer	$0.00	0	0					0	Halton Hills Hydro
Recommended Manufacturer:									
Selected on basis of:	Lowest evaluated ownership cost						Click To Sort From Lowest to Highest		
Notes:									

Figure 4 Transformer Cost Evaluation System

The application states that, “The Total Ownership Cost is expressed by the following formula:

T.O.C. = (unit sale price) + X*NL + Y*FL

Where X = the cost of No Load Losses in dollars per Watt

NL = No-Load losses in Watts

Y = the cost of Full-Load losses in dollars per Watt

FL = Full-Load losses in Watts

The present cost of No-Load losses used in this evaluation is $8.30/ Watt, while the present cost of Full- Load losses is $4.10/ Watt.”

a) Please explain why the present cost of No-Load losses used in calculating Total Ownership Cost is $8.30/Watt, while the present cost of Full-Load losses used in the calculation is $4.10/Watt.
b) Please show how the No-Load and Full-Load loss values were calculated or derived.

2-Staff-8
Ref: Exh 2, Appendix 2-A – Distribution System Plan page 13, Municipal Transformer Station

The application states that, “The Northwest Greater Toronto Area Integrated Regional Resource Plan (NWGTA Region IRRP Report) published April 28, 2015 states in section 7.2.2 that: Halton Hills Hydro should proceed to gain the necessary approvals to construct, own and operate a new step down station at the Halton Hills Gas Generation facility. Halton Hills Hydro should proceed to construct, own and operate a new step down station at Halton Hills Gas Generation facility. Based on technical and economic analysis, the Working Group believes that building this facility is the least-cost option for serving growth within Halton Hills. Currently analysis recommends a targeted in-service date of 2018…"

a) Please provide an update on HHHI's progress in developing the new Municipal Transformer Station ("MTS") project.
b) Does HHHI expect that an in service date of 2018 is still achievable for the proposed MTS project?
c) Please clarify if the proposed MTS project will involve establishing a new substation at (or near) the Halton Hills Gas Generation facility, or if it will instead involve expanding an existing substation at this site?
d) Has HHHI estimated the capital cost of the MTS project? If so, please provide the estimated cost.
e) Given that both HHHI and Milton Hydro Distribution Inc. anticipate the need for new transformation capacity in the next 5 years, has HHHI investigated coordination of the planned investments with Milton Hydro to minimize the aggregated capital expenditures for both distributors?

2-Staff-9
Ref: Exh 2, Appendix 2-A – Distribution System Plan page 13, Municipal Transformer Station
Ref: Report of the Board - *New Policy Options for the Funding of Capital Investments: The Advanced Capital Module* (EB-2014-0219)

The application states that, "As the capital requirement for this project is significant, HHHI intends to file a separate Incremental Capital Module (ICM) for associated expenditures rather than including in this Distribution System Plan."

As noted in the 2016 Filing Requirements, "On September 18, 2014, the OEB issued the Report of the Board - *New Policy Options for the Funding of Capital Investments: The Advanced Capital Module* (EB-2014-0219). The Advanced Capital Module (ACM) reflects an evolution of the Incremental Capital Module (ICM) adopted by the OEB in 2008.

The ACM expands the ICM concept to incorporate the concept of recovery for qualifying incremental capital investments during the Price Cap IR period with an opportunity to identify and pre-test such discrete capital projects documented in the DSP as part of the cost of service application.

As part of a cost of service application, a distributor may propose qualifying ACM capital projects that are expected to be made and come into service during the subsequent Price Cap IR term. These will be discrete projects as documented in the DSP. The distributor must also identify that it is proposing ACM treatment for these future projects, and provide the cost information and materiality threshold calculations to show that these would qualify for ACM treatment based on the forecasted information at the time of the DSP and cost of service application."

a) When does HHHI intend to file the Incremental Capital Module (ICM) for the 230-27.6 kV, 125 MVA MTS project?
b) Please explain why a review for need and prudence is not possible at this time.

2-Staff-10
Ref: Exh 2, Appendix 2-A - Distribution System Plan page 14, Future Growth

The application states that, "The Town of Halton Hills has established a Vision Georgetown Plan which, once implemented, will add about 20,000 people by 2031 to an area of 1,000 acres in southern Georgetown."

a) Has HHHI included any projects in the DSP that are primarily focused upon preparing to serve this projected population growth area? If so, please identify these projects and quantify their capital cost impacts.
b) Is there any risk of stranded investment if the growth projected in the Vision Georgetown Plan forecast fails to materialize?

2-Staff-11
Ref: Exh 2, Appendix 2-A – Distribution System Plan page 17, Future Growth

The application states that, "Halton Hills Hydro has recently expressed concerns regarding load growth and single supply reliability to Acton from Fergus TS feeder M4. This is primarily a distribution planning activity and Halton Hills Hydro and Hydro One Distribution have agreed to assess and develop a plan to address these reliability concerns. Ultimately, this may result in some distribution investments for Halton Hills Hydro."

"Halton Hills Hydro's service territory spans two regional planning zones; the Northwestern Sub region of the GTA West Region and also to the Kitchener-Waterloo-Cambridge-Guelph (KWCG) Region."

a) What is the timing of the planning activities related to the load growth and single supply reliability concerns?
b) When will the magnitude of any required capital expenditures be known, and when would these costs be incurred?
c) Please confirm that none of these costs are included in the capital expenditure forecast provided in this DSP.
d) How does HHHI ensure coordination and optimization of the planning activities of these two Regional Planning groups, at least to the extent that they directly affect HHHI's DSP and Capital Expenditure Plans?

2-Staff-12
Ref: Exh 2, Appendix 2-A – Distribution System Plan, Wood Distribution Poles: Fig. 20 - Age Distribution of In-Service Wood Distribution Poles, Table 6 Condition Categories for Wood Poles, Fig. 21 - Pole Condition, pages 35-36, Fig. 60 Project Priority Matrix, page 104

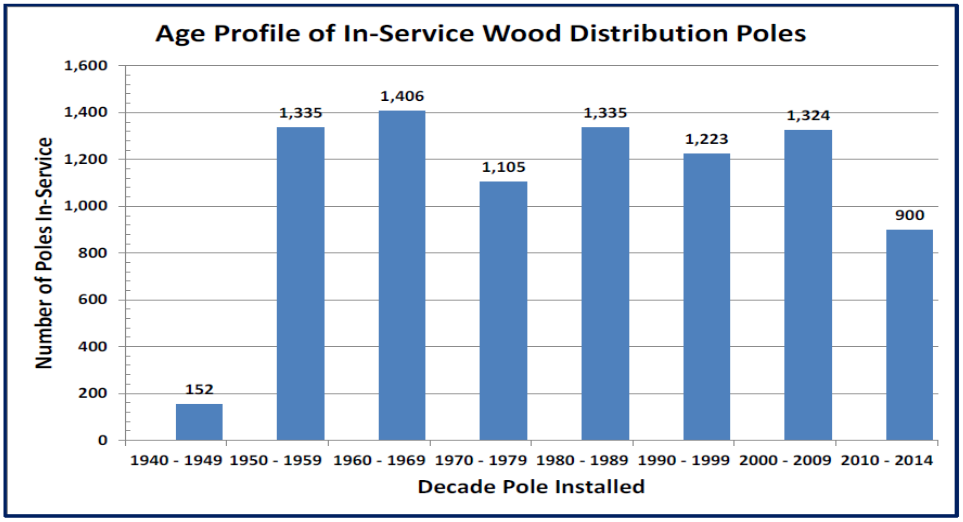


Figure 20 Age Distribution of In-Service Wood Distribution Poles

The application states, “As can be seen in the graph above, Halton Hills Hydro has 1400 poles exceeding their 50 year expected lifespan and an additional 1400 poles approaching end of life. Given this age profile, Halton Hills Hydro has implemented an accelerated pole replacement program targeting 275-280 distribution poles each year for the next ten years.”

Pole Condition	Comments
Good	Cracks, slight rot or feathering.
Fair	Cracks, mechanical damage, surface rot at/ below ground line, moderate rot, pole top feathering/ split.
Fair-Poor	Cracks to ground line, mechanical damage moderate to extensive rot/ decay, pole top feathering/ split.
Poor	Cracks, mechanical damage, extensive damage, rot, and decay at ground line, internal and external decay pockets.

Table 6 Condition Categories for Wood Poles.

The application states, “As can be seen from the chart below, 34% of Halton Hills Hydro poles have some level of damage or wear.”

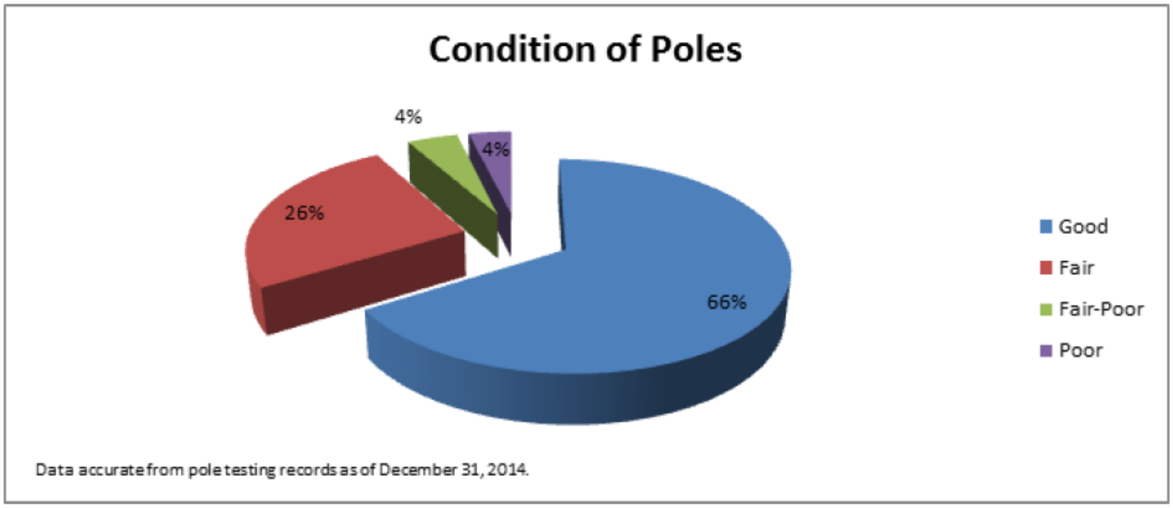


Figure 21 Pole Condition

HHHI has identified that it intends to implement a pole replacement program with a capital cost of $2 million per annum for the next 10 years. Under this plan a total of between 2,750 and 2,800 poles will be replaced over the next 10 years, representing 31% - 32% of HHHI's pole portfolio. This number is nearly equal to the total number of poles assessed as being in "Fair" (26%), "Fair-Poor" (4%) and "Poor" condition (4%).

For an asset class such as wood poles with a 50-year actuarial "Useful Life", approximately 2% of HHHI's 8,780 wood pole portfolio (or approximately 175 poles) would need to be replaced each year over the longer term. HHHI plans to replace 275 to 280 poles, or just over 3% of its pole portfolio, per annum.

Under the OEB's Chapter 5 filing guidelines, Local Distribution Companies are asked to show links between forecast System Renewal capital investments and asset condition.

a) Please fill in the following table with HHHI's pole replacement costs and number of poles replaced each year for the 5-year historical period 2010 – 2014 and to date for 2015.

	Historical Year					To date
	2010	2011	2012	2013	2014	2015
Cost of Pole Replacements						
Number of Poles Replaced						

b) Please fill in the following table, showing the total number of planned pole replacements by forecast year, categorized by the most recent condition assessment of those poles (as represented in the DSP filing).

Pole Condition as Assessed in 2015 DSP	Year					
	2016	2017	2018	2019	2020	TOTAL
GOOD						
FAIR						
FAIR-TO-POOR						
POOR						
TOTAL						

c) Is the accelerated pace of the HHHI pole replacement program described in the DSP based primarily upon assessed pole condition or upon replacing poles that have exceeded the actuarial "Useful Life" threshold?
d) Does HHHI consider "some level of damage or wear" to be an appropriate criterion to trigger pole replacement?
e) How does HHHI determine which poles need to be replaced immediately? In other words, is there a separate category below "Poor" used to identify poles that require immediate replacement?
f) Please explain the relationship between the pole assessment categories given in this section and the priorities shown in Figure 60 Project Priority Matrix on DSP page 104, which range from 1 to 5 for increasing levels of project urgency.
g) How are the pole condition assessment rankings of "Good", "Fair", "Fair-Poor" and "Poor" utilized in the Project Priority Matrix calculations shown in Figure 60?
h) Given the extent of its pole-testing program, has HHHI developed a database or tracking system that enables it to project the rate of pole condition deterioration between categories, e.g.: from "Good" to "Fair", or from "Fair-Poor" to "Poor"?
i) Does a typical wood pole deteriorate from "Fair" to "Poor" condition within the timeframe of a 5-year regulatory cycle?
j) Will HHHI's planned pole replacement program provide tangible ratepayer benefits beyond rejuvenation of the pole portfolio? If so, please explain.

2-Staff-13
Ref: Exh 2, Appendix 2-A – Distribution System Plan: Pole-Trans Transformer Units, pages 47-48

The application states, "The majority of these transformers will reach the end of their useful life in the next five to 10 years. At the same time much of the underground infrastructure supplying PoleTrans will reach its end of useful life. Rather than replacing PoleTrans with similar units Halton Hills Hydro will be replacing PoleTrans transformers with padmounted transformers and installing new primary distribution cable to supply the padmount transformers. This will minimize disruptive impacts to customers and provide the most cost effective and efficient means to upgrade these systems.

Replacement of these transformers is expected to be completed by 2022. The priority of expenditure on these replacements recognizes the following risk factors:

1. Addressing areas with known safety risks to those operating the distribution system or known areas where our distribution system is at risk.
2. Addressing a larger population of devices in the urban centers of Acton and

Georgetown on an annualized basis.

3. Number of customers affected by a potential outage and potential length of outages.
4. Age and condition of the PoleTrans and cable in specific areas."

a) How many of its 77 existing PoleTrans units is HHHI planning to replace over the 5-year DSP forecast period?
b) What is the estimated capital cost impact of this replacement program by year?
c) Are the 4 risk factors listed by perceived priority?
d) If yes to c), why are age and condition listed as the lowest risk factor?

2-Staff-14

Ref: Exh 2, Appendix 2-A – Distribution System Plan: Underground Power Cables, pages 49-50

The application states, "Halton Hills Hydro has piloted with cable rejuvenation technologies in an attempt to renew aged cable assets in an effort to reduce the overall capital expenditure. Further rejuvenation treatments may be forthcoming as Halton Hills Hydro identifies locations in the distribution system where cable life extension makes more sense than cable replacement. Figure 38 below outlines considerations with respect to prioritizing expenditures for cables."

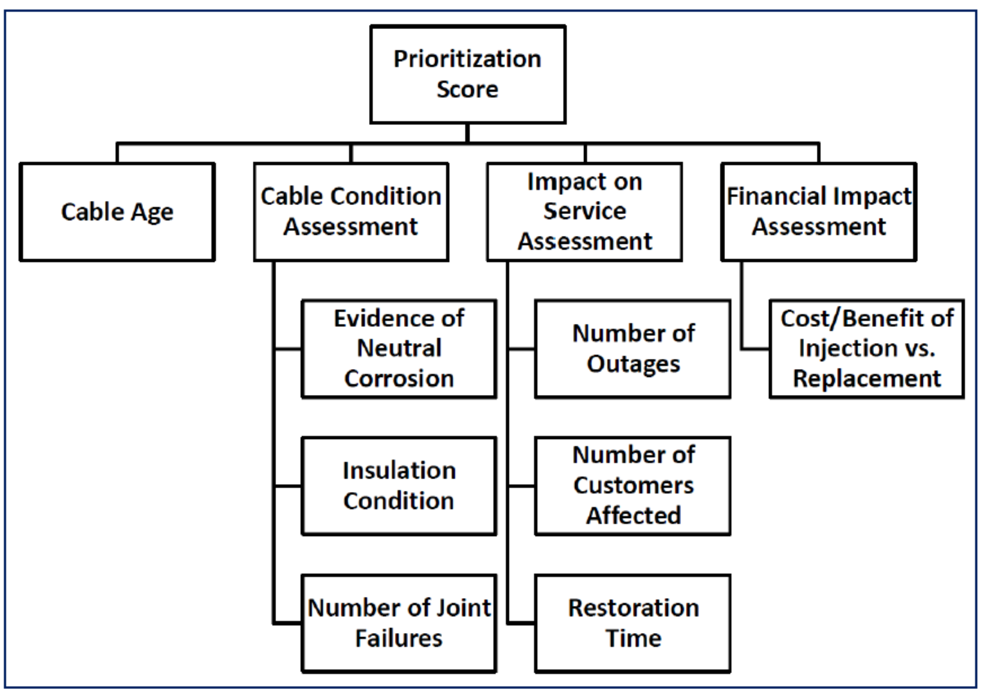


Figure 38 Ranking Scheme for Prioritizing Cable Replacement / Rejuvenation Projects

a) How does HHHI determine that a particular underground cable requires or would benefit from injection treatment, prior to conducting the Financial Impact Assessment process step shown in Figure 38?

b) Has HHHI developed a database to track underground cable failures by vintage, voltage, cable type or any other usefully indicative parameters, to help anticipate future cable failures, or to assist with planning preventive cable replacement or treatment projects?
c) Please quantify the annual capital expenditure reductions achieved to date by adopting the Ranking Scheme shown in Figure 38.

2-Staff-15
Ref: Exh 2, Appendix 2-A – Distribution System Plan: System Capacity Assessment, Table 16 - Feeder Capacities, page 58

The application states, “For planning purposes, the average peak demand for 27.6 kV feeders in Halton Hills is 16 MVA.”

Transformer Station	Owner	Supply Feeders	Supply Voltage	Capacity
Pleasant TS	Hydro One	42M23	44 kV	25 MVA
		42M25	44 kV	25 MVA
		42M28	44 kV	25 MVA
Fergus TS	Hydro One	73M4	44 kV	~ 14 MVA
Halton TS	Hydro One	41M21	27.6 kV	16 MVA
		41M29	27.6 kV	16 MVA
		41M30	27.6 kV	16 MVA

Table 16 Feeder Capacities

a) Please confirm that the HHHI 27.6 kV feeder average peak demand of 16 MVA is not equivalent to the maximum thermal loading capacity of these feeders.
b) What is the emergency thermal loading capacity of HHHI’s 27.6 kV feeders? If maximum capacity is different for summer and winter, please specify.
c) Does HHHI explicitly track its worst performing feeders? If so, please provide a ranked list.
d) Are the worst performing feeders targeted for mitigation in the DSP?

2-Staff-16
Ref: Exh 2, Appendix 2-A – Distribution System Plan: System Capacity Assessment, 27.6 kV Contingency Analysis, page 60

The application states that, “There is sufficient capacity in the feeders to support average peak loading and would support some additional customer load. As was mentioned previously, the southern area served by the 27.6 kV systems is designated as high growth and existing capacity is forecast to be used up by 2018.

Contingency Analysis – Assume loss of one feeder
New feeder count = 2
Load per remaining feeder = 29 MVA / 2 = 14.5 MVA
Surplus = (16 MVA – 14.5 A) x 2 feeders = 3 MVA

Existing feeder surplus = 3 MVA / 16 MVA = 0.2 MVA"

a) If 16 MVA is not the maximum thermally limited capacity of HHHI's 27.6 kV feeders, please explain how this capacity limit was derived.
b) Is it standard utility practice to use a capacity value lower than maximum thermally limited capacity when performing feeder contingency analysis?

2-Staff-17
Ref: Exh 2, Appendix 2-A – Distribution System Plan: System Capacity Assessment, Analysis, page 65

The application states that,

- "Norval MS and Ashgrove MS back each other up.
- Ashgrove MS provides limited, non-peak period back up to both Glen Williams MS and Silver Creek MS
- New load growth is planned on the 8.32 kV system in North West Georgetown and East Acton.
- The power transformer at Silver Creek MS is presently at capacity and has limited ability to accept load transfers.
- The long normal feeder lengths impact the ability to accept load transfers while maintaining optimal power quality

Summary: New capacity will be required for the 8.32 kV system. This requirement is addressed in the Capital Expenditure Plan."

a) Please confirm that the 27.6 kV upgrades that will cause the Norval MS and Ashgrove MS to become redundant also drive the requirement for a new MS to serve growing NW Georgetown and East Acton Rural 8.32 kV loads.
b) Will the addition of a new MS in this area impact the peak loading conditions on the existing local 44 kV feeders?

2-Staff-18
Ref: Exh 2, Appendix 2-A – Distribution System Plan: Asset replacement and maintenance planning, page 66

The application states that, "The timing of the renewal investments with respect to assets is often considered from a condition based assessment but is also viewed with respect to the asset reaching or surpassing the end of its economic useful life."

Does HHHI use "end of its economic useful life" and "end of life" interchangeably in the DSP? If not, how does HHHI differentiate between the two terms?

2-Staff-19
Ref: Exh 2, Appendix 2-A – Distribution System Plan: Porcelain insulators and switches Inspection & Maintenance, page 71

The application states that, "Halton Hills Hydro has developed an ongoing program to rectify an area of concern where premature failure of porcelain line post insulators and switches is occurring. This issue is due to cracking within the porcelain body, water penetration and freezing that weakens the porcelain body causing untimely failure. The utility has directed its workforce to replace any porcelain switch with a polymer type switch when they are working on them in the field. They are also identifying areas where suspect porcelain insulators are located for inspection and replacement purposes."

a) Did HHHI perform a cost-benefit analysis prior to implementing this directive?
b) If yes to a), please provide the analysis highlighting the benefits that will be obtained by implementing this directive.
c) Is this problem unique to HHHI? In other words, is it related to specific batches or production runs of porcelain line post insulators and switches, or is it an industry-wide issue?
d) If it is an industry-wide issue, did HHHI consult with any other utilities affected by the problem prior to deciding upon the current HHHI replacement strategy?

2-Staff-20
Ref: Exh 2, Appendix 2-A – Distribution System Plan: Projects related to innovation, page 100

"The utility implemented this innovative software in November 2014 to improve the accuracy and efficiency by which estimates are created. Quadra also interacts with the utility's financial and inventory systems whereby materials can be requisitioned electronically rather than paper based as was done prior to implementation."

a) Can HHHI provide concrete examples of how the Quadra software has helped improve HHHI cost estimates?
b) Are the benefits reflected in reduced hours to create estimates, or improved estimate accuracy (with reduced contingency allowance requirement)?

OPERATING REVENUE

3-Staff-21
Ref: Exh 2, Appendix 2-A – Distribution System Plan, page 101
Ref: Appendix 2-IA Summary of Actual and Forecast Data

The application states that, "Halton Hills Hydro has seen significant growth over the past number of years. This growth comes in the form of new development in vacant lands (farm fields) as well as in-fill development in established urban neighbourhoods."

OEB staff prepared the following table based on Appendix 2-IA.

	OEB Approved 2012	Actual 2012	Actual 2013	Actual 2014	Bridge 2015	Test 2016
kWh	494,026,422	493,078,700	500,125,974	506,282,929	507,057,514	509,865,892
Customers	21,413	21,116	21,441	21,535	21,715	21,897

a) Please confirm that the data in the table are correct.
b) Please provide 2015 actual kWh and customers.
c) Please confirm that the 2016 proposed load is 3.2% higher than 2012 OEB approved, and that a significant portion of the load increase is related to the Toronto Premium Outlet Mall.
d) Please confirm that the 2016 proposed customer count is 2.3% higher than 2012 OEB approved.
e) Subject to the above, please explain the statement in the application regarding significant growth over the past number of years.

3-Staff-22
Ref: Exh 3 page 15 – CDM Impacts on the 2016 Load Forecast
Ref: Appendix 3-A
Ref: Appendix 2-IA Actual and Forecast Data

a) Table 3-14 on page 15 lists a 2016 purchased load forecast of 540,994 MWh including the impact of CDM, but not the impact of LED streetlights. Please explain why this forecast differs from the forecast of 541,102 MWh noted in Appendix 3-A.
b) Table 3-14 on page 15 lists a 2016 billed load forecast of 511,221 MWh. Please explain why this forecast differs from the forecast of 509,866,419 kWh noted in Appendix 3-A and the 509,865,892 kWh forecast noted in Appendix 2-IA.

3-Staff-23
Ref: Exh 3 page 18, CDM Impacts for LRAMVA

Please provide a table that lists all the appropriate OPA CDM Initiatives that produced net CDM savings which were used in the LRAMVA calculations. For each rate class, please list all relevant CDM initiatives in the applicable year and provide the subsequent net CDM savings for each. An example is provided below:

Residential	**Net kWh**	**Net kW**
Initiative 1		
Initiative 2		
Initiative 3		
Total		
Volumetric Rate Used		
Lost Revenues		
GS < 50 kW	**Net kWh**	**Net kW**
Initiative 1		
Initiative 2		

Initiative 3		
Total		
Volumetric Rate Used		
Lost Revenues		
GS > 50 kW	**Net kWh**	**Net kW**
Initiative 1		
Initiative 2		
Initiative 3		
Total		
Volumetric Rate Used		
Lost Revenues		
Other classes (e.g., Streetlighting, Large Use, etc.), as needed	**Net kWh**	**Net kW**
Initiative 1		
Initiative 2		
Initiative 3		
Total		
Volumetric Rate Used		
Lost Revenues		

A separate table should be provided for each year.

OPERATING EXPENSES

4-Staff-24
Ref: Exh 4 page 37 to xx, OM&A
Ref: Appendix 2-JA – Summary of Recoverable OM&A Expenses

OEB staff has prepared a table based on Exhibit 4 and Appendix 2-JA.

a) Please confirm that the data entries in the table below are correct.
b) Please confirm that with the exception of 2012 actual maintenance cost, HHHI has actually underspent in each OM&A category in the period 2012 to 2014 vs 2012 OEB approved.
c) Please provide 2015 actuals for each OM&A category.
d) Please explain how the trend in Operations and Maintenance spending is consistent with HHHI's strategic objective with respect to reliability.

Expense	OEB Approved 2012	Actual 2012	Actual 2013	Actual 2014	Bridge 2015	Test 2016
Operations	$ 1,049,101	$ 797,619	$ 800,456	$ 791,622	$ 1,265,363	$ 1,355,647
Maintenance	$ 933,985	$ 1,905,957	$ 742,555	$ 615,219	$ 341,000	$ 374,125
One Time Meter Cost		($951,608)				
Sub-Total O&M	$ 1,983,086	$ 1,751,968	$ 1,543,011	$ 1,406,841	$ 1,606,363	$ 1,729,772
Billing and Collecting	$ 1,226,281	$ 1,072,259	$ 1,210,087	$ 1,203,346	$ 1,584,893	$ 1,890,937
Community Relations	$ -	$ -	$ -	$ -	$ -	$ -
Administrative and General	$ 2,584,033	$ 2,036,642	$ 2,331,334	$ 2,568,754	$ 2,929,017	$ 3,134,097
Sub-Total Admin	$ 3,810,314	$ 3,108,901	$ 3,541,421	$ 3,772,100	$ 4,513,910	$ 5,025,034
Total	**$ 5,793,400**	**$ 4,860,869**	**$ 5,084,432**	**$ 5,178,941**	**$ 6,120,273**	**$ 6,754,806**
%Change (year over year)			4.60%	1.86%	18.18%	10.37%
% Change 2016 vs 2012 OEB approved						16.6%
% Change 2016 vs 2014 Actual						30.4%

4-Staff-25
Ref: Exh 2 Appendix H

As part of its application, HHHI filed the results of a Utility Pulse survey of customers to support HHHI's DSP. The Utility Pulse report contained data comparisons where applicable to an Ontario-wide LDC benchmark and to Ontario LDCs participating in Utility Pulse's customer satisfaction survey.

Did HHHI conduct any benchmarking other than the above to support the current cost of service application?

4-Staff-26
Ref: Exh 4 page 56
Ref: Appendix 2-L – Recoverable OM&A Cost per Customer and per FTE

a) Please confirm that the "customer" data provided in Appendix 2-L filed on October 2, 2015 was both customer and connections.
b) Please confirm that the data in the table below, adjusted for customer only data, are correct.
c) The OM&A cost per customer will increase 14% since the last rebasing. Please describe how customers will benefit from this increase.

	Last Rebasing Year - 2012- Board Approved	Last Rebasing Year - 2012- Actual	2013 Actuals	2014 Actuals	2015 Bridge Year	2016 Test Year
Number of Customers	21,413	21,116	21,441	21,535	21,715	21,897
Total Recoverable OM&A	$ 5,793,400	$ 5,812,477	$ 5,084,432	$ 5,178,941	$ 6,120,273	$ 6,754,806
OM&A cost per customer	$ 270.56	$ 275.26	$ 237.14	$ 240.49	$ 281.85	$ 308.48
Number of FTEs	51	50	49	50	51	53
Customers/FTEs	420	422	438	431	426	413
OM&A Cost per FTE	$ 113,596.08	$ 116,249.54	$ 103,763.92	$ 103,578.82	$ 120,005.35	$ 127,449.17

4-Staff-27
Ref: Exh 4 page 56
Ref: Appendix 2-L – Recoverable OM&A Cost per Customer and per FTE

HHHI is a “Mid-size GTA Medium-High & High Undergrounding” distributor. Three other utilities in this group have filed for 2016 cost of service. On the basis of 2014 actual data, OEB staff has prepared the following summary:

		2014 Actual	
Distributor	File Number	OM&A/Customer	Customer/FTE
Halton Hills Hydro	EB-2015-0074	$240	431
Guelph Hydro Electric	EB-2015-0073	$211	549
Milton Hydro Distribution	EB-2015-0089	$247	665
Waterloo North Hydro	EB-2015-0108	$251	413

The 2014 data show that HHHI OM&A expense per customer and customers per FTE are in the mid-range for this group of distributors.

Please provide details on any initiatives undertaken to improve HHHI’s results in these measures.

4-Staff-28
Ref: Exh 2 page 35
Ref: Exh 1 page 30

In 2014, HHHI implemented a new Enterprise Reporting Platform (ERP) financial software package at a cost of $818,918

The application states that, HHHI intends to utilize the new financial reporting system to improve reporting and integrate key business processes while reducing manual processing procedures.

Have the costs related to reduced manual processing been factored into this application? What is the quantum of those benefits?

4-Staff-29
Ref: Exh 4 page 6-7 and 33-34, New FTE

The application states that "HHHI's Information Technology Department regularly uses external contractors to cope with the increased workload. All departments will benefit from this position by having in-house expertise to solve technical and non-technical related issues. This addition will also aid in the avoidance of costs related to external support at a rate of $205 per hour (the hourly rate for service from HHHI's IT system provider). … HHHI has included Business System Analyst in 2016 resulting in an increase of $92,820 in wages and benefits."

Please advise where costs will be avoided (i.e. reduced) by hiring the business system analyst. Please identify specific line items in Table 4-6 on pages 33-34.

4-Staff-30
Ref: Exh 4 page 54 – Management Employees

The application states that, "For management employees, HHHI utilizes the industry standards and benchmarks with LDCs in the Greater Toronto Area (GTA). As shown in Table 4-13, Summary of Wage Increases by Year, the average increase for … the four year period to 2015 [for] management staff, with merit and progression adjustment has averaged 2.86%..."

a) What is the industry standard and benchmark referred to?
b) What was the comparable GTA LDC management increase for the four year period to 2015?

4-Staff-31
Ref: Exh 4 page 68 – Other Post-Employment Benefits

HHHI has recovered OPEBs in rates previously.

a) Please indicate if OPEBs were recovered on a cash or accrual accounting basis for each year since HHHI started to recover OPEBs.
b) Please complete the table below to show how much more than the actual cash benefit payments, if any, have been recovered from ratepayers from the year HHHI started recovering amounts for OPEBs.

OPEBs	First Year of Recovery to 2011	2012	2013	2014	2015	2016	TOTAL
Amounts included in Rates							
OM&A							
Capital							
Sub-Total							
Paid Benefit Amounts							
Net excess amount included in rate greater than amounts actually paid							

c) Please describe what HHHI has done with the recoveries in excess of cash benefit payments.

4-Staff-32
Ref: Exh 4 page 73, Shared Services
Ref: Table 4-27

The application states that, "HHCEC's Executives provide strategic and financial planning, governance, risk management, employee management and mentoring along with Board meeting preparation and attendance to the HHHI business." The actual and forecast costs and revenues are summarized in Table 4-27.

Table 4-27: Shared Services and Corporate Cost Allocation

		2012 Board Approved	2012 Actual	2013 Actual	2014 Actual	2015 Bridge Year	2016 Test Year
Halton Hills Community Energy Corporation (HHCEC)	Parent Corporation	$ 25,000	$ -	$ -	$ -	$ -	$ -
SouthWestern Energy Corporation (SWE)	Affiliate	320,000	306,450	299,687	323,026	331,697	331,697
Harvester Energy Canada Inc.	Affiliate (Amagmated with SWE - January 31, 2014)	43,000	6,000	-	-	-	-
1820259 Ontario Inc., operating as Hummingbird Wireless	Affiliate (Busines Assets sold -September 30, 2011; subsequent January 01, 2012 amalgamated with SWE)	8,000	-	-	-	-	-
Total Intercompany Revenue - 4375 Revenues from Non-Utility Operations		**$ 396,000**	**$ 312,450**	**$ 299,687**	**$ 323,026**	**$ 331,697**	**$ 331,697**
			2012 Actual	2013 Actual	2014 Actual	2015 Bridge Year	2016 Test Year
Services provided BY HHHI to:							
SouthWestern Energy Corporation (SWE)	Water & Sewer billing services and IT Services		252,150	247,697	246,945	253,397	253,397
	Management and administration		54,300	51,990	76,081	78,300	78,300
Harvester Energy Canada Inc.	Management and administration		6,000	-	-	-	-
Services Provided By HHHI			**312,450**	**299,687**	**323,026**	**331,697**	**331,697**
			2012 Actual	2013 Actual	2014 Actual	2015 Bridge Year	2016 Test Year
Services provided TO HHHI to:							
SouthWestern Energy Corporation (SWE)	Sub-Contract work (construction), year end accounting & special projects), smart meter & gatekeeper maintenance, building maintenance.		32,738	205,098	132,228	177,000	177,000
Halton Hills Community Energy Corproartion (HHCEC)	Management services				211,840	268,356	273,723
Harvester Energy Canada Inc.	Panels on Poles - Green Energy Initiative		148,190	3,383			
Services Provided TO HHHI			**180,928**	**208,481**	**344,068**	**445,356**	**450,723**

a) How was this support provided in the period prior to 2014? Are there OM&A reductions in other areas to reflect the change in the source of this support?
b) Has a cost benefit analysis of the approximately $250,000/year HHCEC service been completed? If yes, please provide.

4-Staff-33
Ref: Exh 4 page 83, Depreciation
Ref: Exh 1 page 42

The 2016 forecast depreciation noted on page 83 of Exhibit 4 is $2,530,022, while Exhibit 1 lists $2,356,442. Please reconcile.

4-Staff-34
Ref: Exh 1 page 19, Monthly Billing

Beginning in 2016, HHHI will move to monthly billing for residential and small commercial customers who currently receive bimonthly bills.

a) Please confirm that the move to monthly billing for residential and small commercial customers will be completed by December 31, 2016. If not, please explain why not.
b) Please provide the number of residential and GS <50 kW customers that are currently billed on a monthly and on a bi-monthly basis.

4-Staff-35
Ref: Exh 1 page 44, Monthly Billing
Ref: Exh 4 page 52 OM&A Cost Driver Table

At page 44 of Exhibit 1 it states that, “Monthly billing will [result in] $173,195 in additional costs, **including** staffing, postage, etc. on an ongoing basis.”

Table 4-12, which is also Appendix 2-JB, lists OM&A cost drivers. The New FTE line includes expense for the proposed billing clerk. The “implementation of monthly billing” results in an expense of $173,195 in 2016. That expense **excludes** “FTE billing clerk – included above”.

a) Please reconcile the differences in the two pieces of evidence listed above.
b) Please provide a breakdown of the $173,195 cost associated with the implementation of monthly billing.
c) Please quantify any offsetting costs (benefits) associated with the implementation of monthly billing.
d) Please identify the percentage of customers on e-billing as of December 31, 2015. If HHHI does not provide e-billing to its customers please explain the reasons.
e) Please describe HHHI’s efforts to promote e-billing to its customers.
f) Please describe other initiatives that HHHI has undertaken, or intends to undertake, to manage the costs of monthly billing for all customers.
g) Please provide a breakdown of the $231,918 expense related to new FTEs.

4-Staff-36
Ref: Exh 1 – Achieved Return on Equity

OEB staff has prepared a table of deemed and achieved return on equity. The achieved ROE is sourced from page 41 of Exhibit 1 and from the scorecard provided at Appendix 1-K.

Return on Equity	2010	2011	2012	2013	2014
Deemed	8.57%	8.57%	9.12%	9.12%	8.82%
Achieved -Exh 1 page 41	7.59%	8.47%	12.71%	14.97%	12.91%
Achieved - Exh 1 App 1-K		9.14%	13.30%	14.97%	12.91%

a) Please explain the difference in the achieved return on equity from the two sources for the years 2011 and 2012 within the current application.
b) Which achieved return on equity is correct?
c) The application states that, “HHHI's profitability based on the achieved rate of return on equity for historical years 2010 to 2011 are within the allowed dead band of ±300 basis points. The 2012, 2013 and 2014 are above the allowed dead band, the result of tax recovered by HHHI in relation to following CRA Interpretation Bulletin IT-l 28R: Capital Cost Allowance - Depreciable Property to expense amounts capitalized under MIFRS requirements .. .”
   i. Please provide the $ value of the overearnings related to applying the Bulletin IT-I 28R resulting in expensing items that were previously capitalized for tax purposes for each of the years 2012, 2013 and 2014.
   ii. What other drivers contributed to the over earning in the period 2012 to 2014. Please provide the analysis in $ as well as in % of overearnings for each of the years 2012, 2013 and 2014.

4-Staff-37
Ref: Exh 1 – Achieved Return on Equity
Ref: Attachment 1 to OEB Staff Interrogatories

An analysis of 2014 return on equity is provided at Attachment 1 of these interrogatories.

a) Please confirm the data.
b) Will the tax planning and expense control driver and the revenue driver identified in this analysis of 2014 return on equity continue to persist?
c) Please provide a forecast of 2015 ROE performance using the actual information from January 1 to November 30, 2015 and forecast information for December 2015.
d) Please provide the return on equity performance results for 2015 adjusted for taxes.

4-Staff-38
Ref: Exh 4 pages 95-98

The evidence indicates that HHHI has amended its tax returns for years 2011, 2012, 2013, and 2014. However, only the 2014 tax return has been filed.

a) Please file all tax returns that have been amended.
b) Please provide the Notice of Assessment and /or Re-assessment received from the CRA for all applicable years.
c) For each of the Tables on page 97 of the evidence, please provide the calendar year in the column headings.
d) Is HHHI expensing these costs only for income tax purposes?
e) What is the treatment of these costs for financial accounting purposes, i.e. are they being expensed or capitalized?
f) What is the treatment of these costs for regulatory purposes, i.e. are they being expensed or capitalized?

4-Staff-39
Ref: Revenue Requirement Workform (RRWF) and PILs Workform

a) PILs Workform, Tab Taxable Income – Test Year shows "Other Deductions" of $2,950,000 on line 394, and for 2015 bridge year, there are "Other Deductions" of $2,248,880 on line 394. Please explain what these amounts pertain to.
b) RRWF, Tab Utility Income shows a negative PILs amount of $220,666. This amount was added to Utility Income before Income Taxes of $2,091,242, arriving at Utility Net Income of $2,311,908.
    i. Given that HHHI has calculated a regulatory taxable loss of $1,250,441 and is projecting a loss for tax purposes, why is any PILs being calculated?
    ii. Please explain the rationale for a negative PILs amount and for increasing the loss for tax purposes by the same amount for the test year, given the loss position resulting in no taxes being calculated.

COST OF CAPITAL

5-Staff-40
Ref: Exh 5, page 5

The application states that, "HHHI has a promissory note with The Corporation of The Town of Halton Hills, its municipal shareholder, in the amount of $16,141,970. The promissory note was renewed on December 4, 2014 with a maturity date of December 31, 2020."

a) HHHI has requested that the deemed long term debt rate apply to the promissory note. As the note has only been renewed for six years, please explain why the deemed long term debt rate, which is typically applied to 30 year debt, is applicable in this case.

b) The promissory note at Appendix 5-A states that, “Interest shall be payable by Halton Hills Hydro Inc. to The Corporation of the Town of Halton Hills, or assign, at a rate of interest per annum, compounded annually not in advance, prescribed, from time to time, by the Treasurer of The Corporation of the Town of Halton Hills…” What is the current prescribed rate?

5-Staff-41
Ref: Exh 5, page 11

The summary of 2016 test year debt instruments lists a “Capital Loan – 2016” with a third party with a start date of August 31, 2016. What is the status of this proposed debt?

5-Staff-42
Ref: Exh 5, page 8

Please update the cost of capital per the OEB letter of October 15, 2015 regarding Cost of Capital Parameter Updates for 2016 Applications.

REVENUE DEFICIENCY

6-Staff-43
Ref: Exh 6 pages 4 and 9

In the determination of net income for 2016, an OM&A expense of $6,757,846 is used, while on page 9 of Exhibit 6 and elsewhere in the application OM&A expenses are listed as $6,754,806. Please reconcile.

RATE DESIGN

8-Staff-44
Ref: Exh 8 page 7
Ref: Cost Allocation Model
Ref: Chapter 2 Filing Requirements For Electricity Distribution Rate Applications - 2015 Edition for 2016 Rate Applications, page 57

Table 8-6 on page 7 of Exhibit 8 summarizes monthly fixed charges for HHHI rate classes.

a) The last column of the table lists monthly fixed charges from the cost allocation model. There is no $103.83 charge in the cost allocation model for the GS > 1000 to 4999 kW class. How was this charge determined?

b) At page 57 of the filing requirements it states, “If a distributor’s current fixed charge for any non-residential class is higher than the calculated ceiling, there is no requirement to lower the fixed charge to the ceiling, nor are distributors expected to raise the fixed charge further above the ceiling for any non-residential class.” Please explain the rationale for the following rate classes whose monthly fixed charge is currently above the ceiling and monthly fixed charge MFC is proposed to be increased: GS<50 kW and GS>50 to 999 kW.

8-Staff-45
Ref: Chapter 2 Filing Requirements For Electricity Distribution Rate Applications - 2015 Edition for 2016 Rate Applications, page 63

a) What is the total bill impact, including the combined effects of the shift to fixed rates and other bill impacts associated with changes in the cost of distribution service, for a residential customer at the distributor’s 10th consumption percentile?
b) Please provide a description of the method used to derive the 10th consumption percentile. The description should include a discussion regarding the nature of the data that was used (e.g. was the source data for all residential customers or a representative sample of residential customers).

DEFERRAL AND VARIANCE ACCOUNTS

9-Staff-46
Ref: Exh 9 page 15, Extraordinary Event Costs
Ref: Decision EB-2014-0211 issued December 12, 2014

HHHI submitted a Z-factor application for recovery of cost related to the 2013 ice storm. The decision stated, “The Board has also considered the collection period over which the rate riders will be charged. Given the timing of this Decision and to allow sufficient time for the draft rate order process, the Board finds it appropriate to establish January 1, 2015 as the start date for the fixed rate riders. As a result, the Board directs Halton Hills Hydro to **recalculate the final balance to accrue interest until December 31, 2014** and calculate the rate riders based on a 22-month recovery period, to coincide with the October 31, 2016 end date proposed by Halton Hills Hydro.” The OEB approved rate riders to collect $1,561,371.

In the current application, HHHI seeks additional recovery of $18,637. HHHI states that it received additional invoices for legal and intervenor fees late in 2014. In addition, HHHI states that, “Additionally, the original application forecasted carrying charges up to October 31, 2014. However, the approval for disposition did not occur until January 2015 and as such, residual carrying charges in the amount of $4,791 remained in USofA 1572 as at December 31, 2014.”

a) Please confirm whether HHHI complied with the OEB direction in the EB-2014-0211 decision to recalculate interest on the balance until December 31, 2014 and to calculate rate riders.
b) Please explain how the current request is consistent with the OEB's direction in the EB-2014-0211 regarding recalculation of "the final balances".

9-Staff-47
Ref: Exh 2 pages 20 and 23
Ref: Exh 9 page 4

HHHI has calculated a balance of zero for Account 1575 as of the changeover date of January 1, 2015. OEB staff notes that HHHI had a credit of approximately $6.7 Million in Account 1995 – Customer Contributions as of the changeover date. According to APH Article 510, under IFRS, customer contributions received subsequent to the transition date are recognized as deferred revenue. Customer contributions recognized prior to the transition date are not reclassified to deferred revenue as a result of electing the optional exemptions.(Emphasis added)

a) Please confirm that HHHI has reviewed Article 510 in determining that account 1575 should have a zero balance as of the changeover date of January 1, 2015.
b) If confirmed, please explain why there is a zero balance. If the balance is to be revised, please provide the calculation. While OEB staff has not identified any other impacts that should be captured in account 1575, for customer contributions, there may need to be an amount for the difference between HHHI's revised CGAAP based amount for customer contributions as of the changeover date, and the MIFRS based amount for customer contributions as of the same date.

9-Staff-48
Ref: Exh 9 page 7

a) HHHI has indicated that it does not perform regular true-ups of the 1st estimate to actual Global Adjustment rates (GA). Had HHHI trued up the balance proposed for disposition in this application, would the proposed allocations to the RPP and non-RPP change for the commodity accounts?
b) Does HHHI true up the estimated split of RPP to non-RPP when settling power and GA charges with the IESO?

9-Staff-49
Ref: Exh 9 page 13, IFRS Transition Costs

HHHI made changes to its capitalization and depreciation policies in 2012, and adopted IFRS in January 2015. HHHI has proposed disposition of $732,684 for IFRS transition costs. This amount includes projected costs of $15,000 for 2015 Bridge year.

a) Why does HHHI believe that there would be further IFRS transition costs since it has been working on transition since 2010?

b) Has HHHI received an invoice from the vendor for these costs yet?
c) Please explain what these costs relate to, and if they are incremental costs.

9-Staff-50
Ref: Exh 9 page 19
Ref: EDDVAR Tab 'Allocation of Balances'

a) OEB staff notes that HHHI has calculated a separate rate rider for Account 1568. Since the amount for disposition is relatively small, there is no rate rider calculated for some of the rate classes. The disposition of this account can be combined with the Group 1 rate rider calculation as these accounts are allocated to the rate classes in the same manner. Please provide an alternative calculation for Group 1 Rate Riders excluding GA.
b) HHHI has requested OEB's approval to establish several sub-accounts of Account 1595. OEB staff notes that the descriptions of the various Sub-accounts does not accurately reflect the various rate riders they would be tracking. Please provide Sub-account descriptions that accurately reflect the underlying rate riders.

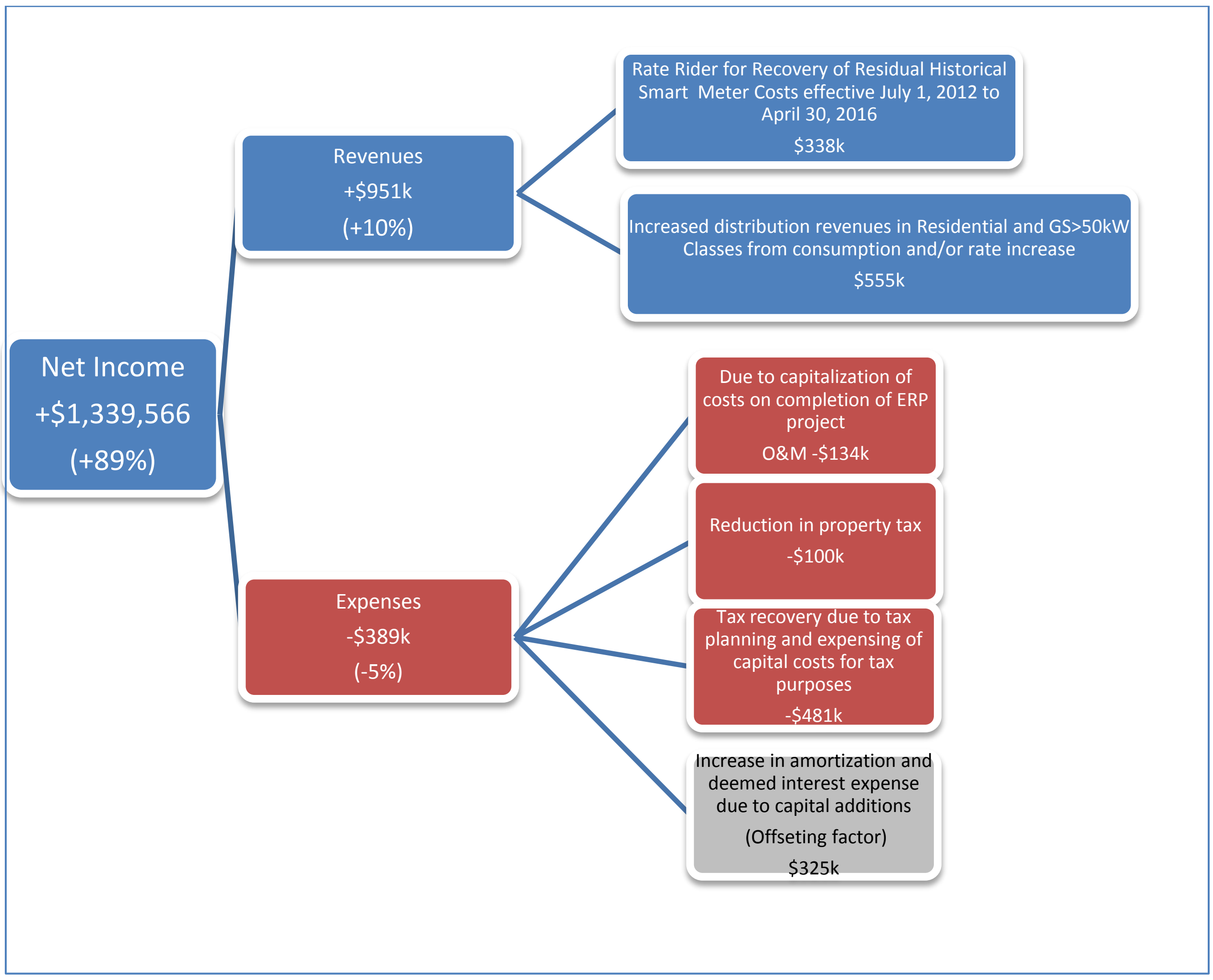
Attachment 1 2014 ROE Over-Earner: Halton Hills Hydro Inc.

Halton Hills is scheduled to come in 2016 for its CoS rate application.

2014 ROE performance – 12.91% (409 basis points over deemed ROE)

	Deemed 2012 EDR	Achieved 2014	Variance	Variance %
ROE$/ Regulated Net Income	$1,496,896	$2,836,462	$1,339,566	**89%**
Regulated Deemed Equity	$16,971,602	$21,967,812	$4,996,210	29%
ROE	**8.82%**	**12.91%**	**4.09%**	**46%**

Drivers for Over-Earning in 2014



Historical ROE performance (2011 to 2014)