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.

Response:

a) Actual contributed capital for 2012 should be ($1,085,377) rather than $39,153 as shown in Table 2 -25. The change was between the opening balance and the actual addition for 2012 and as such there is no impact to revenue requirement.

b) Based on the changes in part a) above, 2012 actual contributed capital is consistent with the audited financial statements.

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.

Response:

HHHI will not be completing a lead-lag study.

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.

Response:

Below in Table IRR - 13 is the updated working capital cost of power calculation (Exhibit 2, Tab 1, Schedule 3, Page 43 Table 2-32A in Application) for 2016 based on the OEB's RPP Price Report for the Regulated Price Plan issued on October 15, 2015, the updated Wholesale Market Charge and the new Ontario Energy Support Plan Charge. HHHI has not reflected the new Uniform Transmission Rates (EB-2015-0311) released January 14, 2016.

Table IRR - 13 : Updated Working Capital Cost of Power Calculation

HHHI 2016 Cost of Power Calculation

2016 Load Foreacst	kWh	kW	2014 %RPP
Residential	193,851,901		96%
General Service < 50 kW	47,621,962		82%
General Service 50 to 999 kW	147,798,837	391,807	11%
General Service 1000 to 4 999 kW	116,864,174	315,299	0%
Street Lighting	1,466,975	4,090	0%
Sentinel Lighting	464,833	633	0%
Unmetered Scattered Load	932,138		0%
TOTAL	**509,000,819**	**711,829**	
	-	-	

Electricity - Commodity RPP Class per Load Forecast RPP	2016 Forecasted	2016 Loss Factor		2016	
Residential	186,097,824	1.0560	196,519,303	$0.10728	$21,082,591
General Service < 50 kW	39,050,008	1.0560	41,236,809	$0.10728	$4,423,885
General Service 50 to 999 kW	16,257,872	1.0560	17,168,313	$0.10728	$1,841,817
General Service 1000 to 4 999 kW	0	1.0560	0	$0.10728	$0
Street Lighting	0	1.0560	0	$0.10728	$0
Sentinel Lighting	0	1.0560	0	$0.10728	$0
Unmetered Scattered Load	0	1.0560	0	$0.10728	$0
TOTAL	**241,405,705**		**254,924,424**		**27,348,292**

Electricity - Commodity Non-RPP Class per Load Forecast	2016 Forecasted	2016 Loss Factor		2016	
Residential	7,754,076	1.0560	8,188,304	$0.10674	$874,020
General Service < 50 kW	8,571,953	1.0560	9,051,982	$0.10674	$966,209
General Service 50 to 999 kW	131,540,965	1.0560	138,907,259	$0.10674	$14,826,961
General Service 1000 to 4 999 kW	116,864,174	1.0560	123,408,567	$0.10674	$13,172,630
Street Lighting	1,466,975	1.0560	1,549,126	$0.10674	$165,354
Sentinel Lighting	464,833	1.0560	490,864	$0.10674	$52,395
Unmetered Scattered Load	932,138	1.0560	984,338	$0.10674	$105,068
TOTAL	**267,595,114**		**282,580,440**		**30,162,636**

Transmission - Network Based on 2014 Actual		Volume Metric		2016	
IESO					$623,779
Hydro One					$3,030,275
TOTAL					**$3,654,054**

Transmission - Connection Based on 2014 Actual		Metric		2016	
IESO					$510,910
Hydro One					$2,358,238
TOTAL					**$2,869,148**

Wholesale Market Service Class per Load Forecast		Volume Metric		2016	
Residential		kWh	204,707,607	$0.0047	$962,126
General Service < 50 kW		kWh	50,288,791	$0.0047	$236,357
General Service 50 to 999 kW		kWh	156,075,572	$0.0047	$733,555
General Service 1000 to 4 999 kW		kWh	123,408,567	$0.0047	$580,020
Street Lighting		kWh	1,549,126	$0.0047	$7,281
Sentinel Lighting		kWh	490,864	$0.0047	$2,307
Unmetered Scattered Load		kWh	984,338	$0.0047	$4,626
TOTAL			**537,504,865**		**$2,526,273**

Rural Rate Assistance Class per Load Forecast		Volume Metric		2016	
Residential		kWh	204,707,607	$0.0013	$266,120
General Service < 50 kW		kWh	50,288,791	$0.0013	$65,375
General Service 50 to 999 kW		kWh	156,075,572	$0.0013	$202,898
General Service 1000 to 4 999 kW		kWh	123,408,567	$0.0013	$160,431
Street Lighting		kWh	1,549,126	$0.0013	$2,014
Sentinel Lighting		kWh	490,864	$0.0013	$638
Unmetered Scattered Load		kWh	984,338	$0.0013	$1,280
TOTAL			**537,504,865**		**$698,756**

Low Voltage Based on 2014 Actual				2016	
Hydro One					$1,373,936
TOTAL			**0**		**$1,373,936**

Smart Meter Entity Fee Class per Load Forecast		Volume Metric		2016	
Residential		Per Month	19,955	$0.7880	$188,690
General Service < 50 kW		Per Month	1,696	$0.7880	$16,041
TOTAL			**21,651**		**$204,731**

Description	2016
4705-Power Purchased	57,510,928
4708-Charges-WMS	2,526,273
4714-Charges-NW	3,654,054
4716-Charges-CN	2,869,148
4730-Rural Rate Assistance	698,756
4750-Low Voltage	1,373,936
4751-Smart Meter Entity Fee	204,731
TOTAL	**68,837,826**

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.

Response:

a) The above data is confirmed correct. HHHI's target is to remain within the Board target as it appears on HHHI's Scorecard. Please note that Table IRR 14 has been updated to reflect the Board targets as they appear on HHHI's 2014 Scorecard.

b) HHHI's Service Quality and Reliability Indicators, excluding 2013, have been updated and are shown in Table IRR - 14.

Table IRR - 14 : HHHI's Service Quality and Reliability Indicators (excluding 2013)

Service Quality Indices	Board Target	2014	2012	2011	2010	4-year Average (excluding 2013)
Including Loss of Supply						
SAIDI	1.23 - 2.08	1.25	1.53	1.55	1.78	1.526
SAIFI	1.34 - 2.75	1.61	1.90	1.67	2.75	1.984
Excluding Loss of Supply						
SAIDI	1.23 - 2.08	1.21	1.23	1.38	1.78	1.398
SAIFI	1.34 - 2.75	1.47	1.34	1.49	2.75	1.761

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.

Response:

a) The formula used for calculating the total ownership cost of a transformer, including the cost of losses, was developed by the former Municipal Electric Association (MEA) and adopted by the utility industry in 1998. Evaluating the losses of a distribution transformer consists of evaluating core loss (no-load) and load loss both having energy and demand costs. Additional factors such as energy costs, rate of return, percent utilization, peak loss, and loss factor are all considered by the MEA in their formulae.

b) The derivation of the values used for no load and full load losses was developed by the MEA and adopted as discussed in response to (a) above.

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?

Response:

a) HHHI is presently working with a project consultant and recently made the land purchase. A design RFP has been issued for selection of a design consultant in early 2016.

b) Yes, HHHI expects that an in service date of 2018 is still achievable for the proposed MTS project.

c) The MTS project involves establishing a new substation near the Halton Hills Gas Generation facility.

d) Yes, the capital cost of the MTS project was estimated at approximately $19 million as reported on page 11 of the IESO IRRP report.

e) Yes, Coordination of both utility needs has been investigated through the IESO IRRP process.

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.

Response:

a) HHHI intends to file its Incremental Capital Module (ICM) for the MTS project as part of an IRM application closer to the expected in-service date (expected 2018).

b) Report of the Board - *New Policy Options for the Funding of Capital Investments: The Advanced Capital Module* (EB-2014-0219) page 14 states:

> *"as part of the cost of service application, distributors must provide a preliminary estimate of the materiality threshold value (and consequently, the total eligible incremental capital amount) for the subject year in which the proposed project is planned to enter service in order to provide the Board with a degree of certainty that the distributor will meet the threshold criteria".*

At the time of the Cost of Service application preparation, HHHI was still in the process of preparing a project plan for the design and construction of the MTS. As such, cost estimates and design details were not available. As HHHI did not have any cost estimates to use in determining if the project would exceed the materiality threshold calculated, HHHI determined that it would not be prudent to submit an ACM at the time of the Cost of Service application.

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?

Response:

a) HHHI's DSP contains a number of planned projects to provide sufficient power to the Vision Georgetown lands. The projects identified in the DSP include the phasing out of vintage 4.8/ 8.32Y kV rural distribution in the southern region of our service territory and which would not support the potential capacity requirements of such a large scale development. The projects identified by year taken from Table 20 in the DSP are as follows:

Table IRR - 15 : Vision Georgetown Projects by Year

Year of Project	Project Title	Estimated Cost ($)
2016	Voltage Conversion, 5 Side Road (Trafalgar Road to 8th Line) - Construction	408,694
2016	Voltage Conversion, 5 Side Road (8th Line to 9th Line) – Design only	19,643
2017	Voltage Conversion, 5 Side Road (8th Line to 9th Line) – Construction	412,235
2017	Voltage Conversion, 5 Side Road (9th Line to 10th Line) – Design only	22,728
2018	Voltage Conversion, 5 Side Road (9th Line to 10th Line) – Construction	453,395
2018	Voltage Conversion, 6th Line (5 SdRd to10 Sdrd & 6th Line to Trafalgar Road) – Design only	41,218
2019	Voltage Conversion, 6th Line (5 SdRd to10 SdRd & 6th Line to Trafalgar Road) – Construction	798,356
2019	Voltage Conversion, 6th Line (10 Sdrd to 15 SdRd & 6th Line to Trafalgar Road) – Design & Construction	778,218
2020	Voltage Conversion, 6th Line (10 Sdrd to 15 SdRd & 6th Line to Trafalgar Road) – Design & Construction	730,718

b) HHHI does not anticipate that Vision Georgetown will fail to materialize as is evidenced in the letter from the Town of Halton Hills in Appendix IRR -B.

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?

Response:

a) Timing of the planning activities is anticipated to occur over the next two years (2016-2017).

b) The magnitude of any capital expenditures would likely be known in approximately two to three years once Hydro One and HHHI have had a chance to develop options and review costs. Capital expenditures would likely not be incurred in the IR period covered by the current application.

c) None of these costs have been included in HHHI's DSP.

d) HHHI is ensuring coordination and optimization of the planning activities through communication with Hydro One to ensure identified needs are addressed. HHHI is represented on the KWCG planning group by Hydro One since HHHI is an embedded distributor to Hydro One in this area.

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

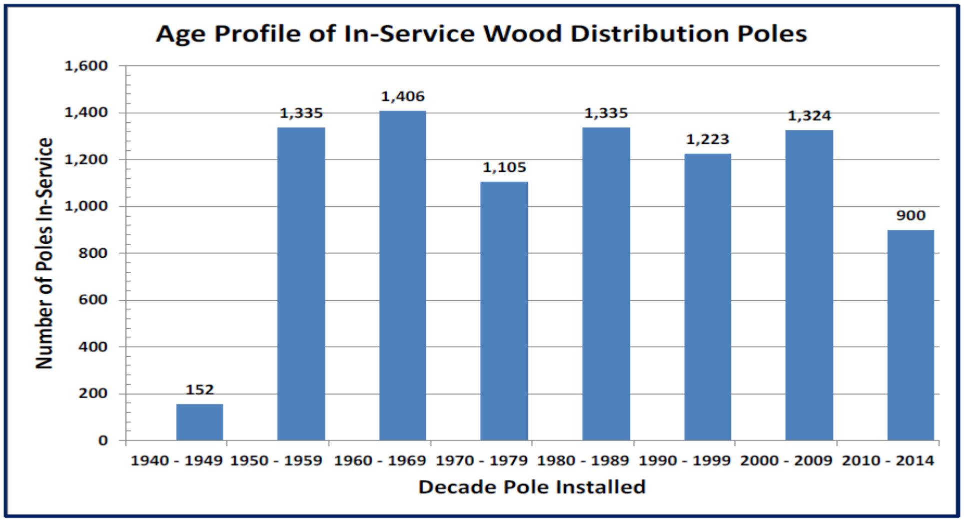

Figure 20 Age Distribution of In-Service Wood Distribution Poles

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."

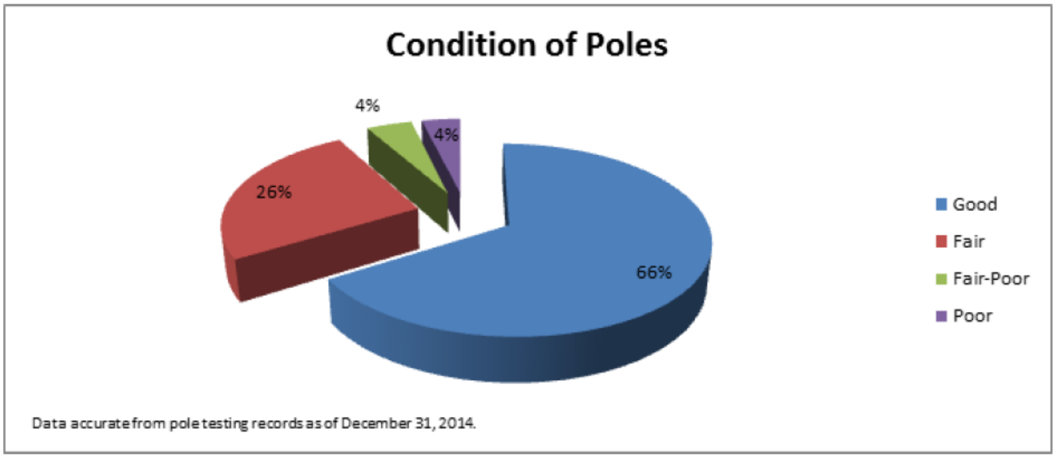

Figure 21 Pole Condition

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	Year					
Assessed in 2015 DSP	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.

Response:

a) Please see Table IRR - 16.

Table IRR - 16 : Pole Replacement

	Historical Year					To Date
	2010	2011	2012	2013	2014	2015
Cost of Pole Replacements	$ 222,644.00	$ 777,092.00	$ 1,180,177.12	$ 1,183,227.13	$ 1,908,706.37	$ 1,195,760.68
Number of Poles Replaced	30	41	183	143	181	144

b) HHHI intends to replace 275-280 poles annually over the forecast period. At present HHHI has not identified the number of poles as it relates to pole condition that will be replaced each year. HHHI will focus on "defective" poles identified during pole testing and pole assets that have surpassed end of life.

c) HHHI's accelerated pole replacement program is a proactive measure that addresses pole condition assessments and risks involved with operating significantly aged assets that have surpassed their useful life.

d) No, HHHI conducts annual pole inspections and testing using a qualified inspection company. Their assessment of pole condition and identification of defective poles provide criteria for pole replacements.

e) During annual testing a quantity of poles are normally identified as "defective" and to be replaced in the same year as the testing. HHHI uses these recommendations of the pole testing company and prepares work packages to effect the replacement of the identified poles.

f) The relationship between the project priority matrix depicted in Figure 60 of the DSP and the pole condition assessment categories is such that poles identified in declining condition would have a higher priority to be replaced.

g) See response to (f).

h) HHHI maintains a database related to pole inspections, testing, and the data gathered from our annual inspection program. HHHI does not project the rate at which a poles condition may change from one category to another (ex. Fair – to Poor).

i) HHHI does not have statistical information to be able to answer this question.

j) HHHI's pole replacement program will provide tangible benefits to ratepayers as when a pole is replaced the equipment (brackets, insulators, transformers, etc.) are replaced with new equipment at the same time. New equipment is more reliable and more efficient than older equipment (ex. transformers are more efficient today than 25-30 plus years ago). Renewed assets ensure that our distribution system will continue to meet our customer service focused mission of providing distribution excellence in a safe and reliable manner.

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?

Response:

a) Over the 5-year DSP forecast period HHHI plans to replace 63 of the 77 in-service PoleTrans transformers.

b) The following Table IRR - 17 provides a year-by-year comparison of planned capital expenditures. The dollar amounts reflect design and construction costs summed per year.

Table IRR - 17 : Poletrans Capital Costs by Year

	2016	2017	2018	2019	2020
Annual Cost	$538,100	$603,100	$555,500	$547,125	$294,419
Quantity of PoleTrans	14	22	11	9	7

c) The four (4) risk factors identified in Engineering Report SP14-03 are not organized in a declining order of severity. The four (4) risk factors are the most significant factors related to operating the aged and obsolete assets in our distribution system.

d) Not applicable as the answer to (c) is no.

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."

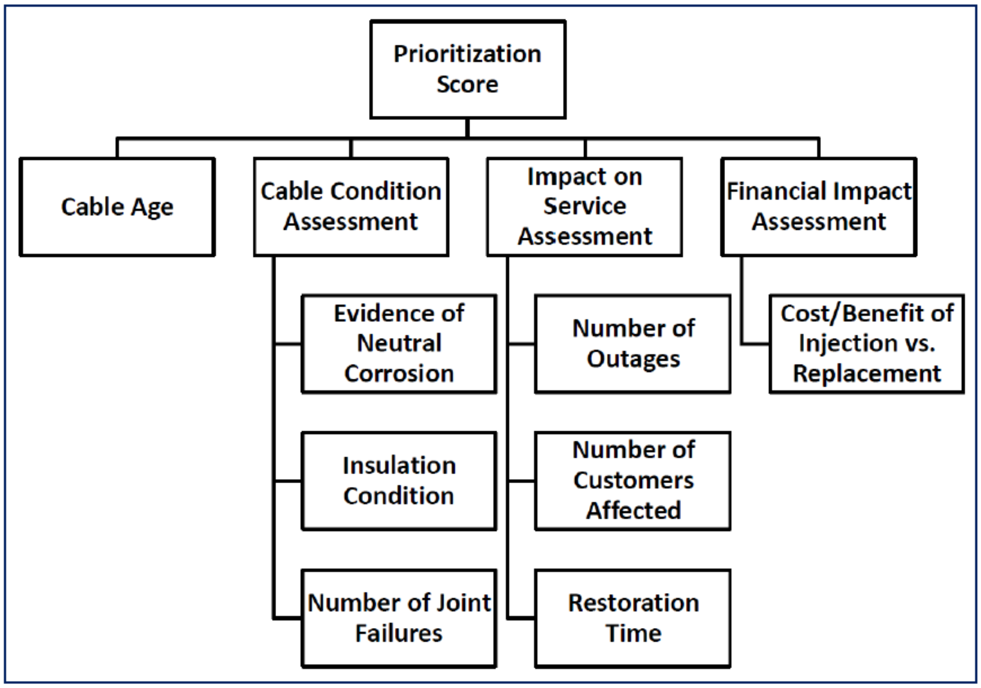

Figure 38 Ranking Scheme for Prioritizing Cable Replacement / Rejuvenation Projects

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.

Response:

a) HHHI has only piloted cable rejuvenation technologies thus far. Cables on which rejuvenation was piloted were identified after having failed and are direct buried (not in duct) where replacement may have been a viable but costly option.

b) HHHI has not developed a database to track underground cable failures.

c) At this time the pilot project is still underway and therefore no final financial analysis can be performed at this time.

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?

Response:

a) Confirmed. 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) The emergency thermal loading capacity of HHHI's 27.6 kV feeders is approximately 28 MVA.

c) No, HHHI does not explicitly track its worst performing feeders.

d) Not applicable.

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?

Response:

a) The 16 MVA limit is an historical average peak loading limit set by Hydro One for 27.6 kV feeders. It is based on the Limited Time Rating (LTR) of typical DESN transformer stations and their respective feeder count. This limit is used for planning purposes to determine when additional feeders are required and is also used to determine the approximate maximum distance over which a typical feeder with distributed load may reach under normal and emergency conditions.

   HHHI normally operates it's feeders with a long reach (approx. 16-18 km) and due to geography, most of the load is at the far ends of the feeders. Under emergency conditions (such as when one feeder supplies the load of another), HHHI is able to maintain adequate voltage at this average limit per feeder.

b) No, the rated capacity of a system (or feeder) is usually determined by its maximum thermal limit for contingency analysis. However, it is also standard practice to adjust and use a lower than maximum thermal limit when voltage drop limitations are exceeded such as happens with longer feeder reach.

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?

Response:

a) The 27.6 kV upgrades that will cause the Norval MS and Ashgrove MS to become redundant do not drive the requirement for a new MS to the north. The key drivers for the new MS are load growth in NW Georgetown and East Acton as well as reliability improvements on the northern portion of the 8.32 kV system.

b) There will be minimal impact to the peak loading conditions on the local 44kV feeders with the addition of the new MS.

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?

Response:

The terms "end of its economic useful life" and "end of life" are interchangeable in Appendix 2-1 page 66.

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?

Response:

a) HHHI did not perform a cost benefit analysis as the work was to address a potential safety hazard affecting field staff safety as well as impacts to reliability.

b) N/A.

c) The use of porcelain insulators and their inherent issues are not unique to HHHI. When a porcelain insulator or switch fails there is a potential for unplanned power interruptions as is noted within the DSP and Engineering Report SP14-03 "Multi-Year Electricity Distribution System Asset Management Plan: 2016-2020". Porcelain insulators have been used by utilities for many years however, HHHI cannot provide comment as to an industry wide issue. The program HHHI has implemented is proactive in nature and aims to replace materials that present a known issue that impacts service quality to customers and safety for HHHI field staff.

d) HHHI is aware that other Ontario LDC's have experienced similar issues with porcelain devices.

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)?

Response:

a) Quadra software is directly linked to HHHI's inventory management system and pulls current inventory pricing directly from the inventory management system. This retrieval method ensures that pricing for materials is current. Further, HHHI has input its construction standards (assemblies) into Quadra from which construction estimates for labour, equipment, and materials are developed. As projects are designed and estimates developed, Quadra allows the user to update estimates to reflect changes in the design by replacing one assembly with another and maintaining current pricing for materials, labour, and equipment.

b) Quadra has been in use for one (1) year at HHHI. The benefits seen thus far are the ability to produce improved estimates based on construction standards (assemblies) and improve job analysis.

2-Energy Probe-6

Ref: Exhibit 2, Tab 1, Schedule 1, pages 4-6

a) Please explain what HHHI means that it proposes no adjustment to revenue requirement (page 5, lines 21-24) because the Steeles Avenue Projects cost was greater than the Board approved amount.

b) Please confirm that the amounts shown in Table 2-3 are the amounts closed to rate base in each year, and not simply the capital expenditures that took place in those years.

c) Are the figures in Table 2-3 (including the amounts per the partial settlement agreement) net of any contributions received, if applicable?

d) Please provide a table that shows the revenue requirement associated with the amount as per the partial settlement agreement broken out into its components (for example, cost of debt, return on equity, depreciation) in one column and the corresponding figures based on the actual amount included in rate base for 2012.

Response:

a) HHHI did not credit any revenue requirement to the asymmetrical account for the Steeles Avenue Projects in the 2012 for the reasons explained in Exhibit 2, Tab 1, Schedule 1, page 5.

b) The amounts shown in Table 2-3 are the capital expenditures in each of the years as the projects cannot be closed out to rate base until they are completed.

c) The figures in Table 2 -3 are net of capital contributions

d) Table IRR - 18 below shows the revenue requirement base on the actual amount included in rate base for 2012. The revenue requirement as per the partial settlement agreement will be the same as the amount included in 2012 as the projects were not closed out to rate base in 2012.

Table IRR - 18 : Revenue Requirement Based on the Actual Amount Included in the Rate Base for 2012

	Revenue Requirement included in 2012 Rate Base
Capital Expenditure	1,544,339
Depreciation Expense - (50 Yrs, Half Yr)	15,443
Net Book Value	1,528,896
OM&A	-
Fixed Assets Opening Balance 2012	-
Fixed Assets Closing Balance 2012	1,528,896
Average Fixed Asset Balance for 2012	**764,448**
Working Capital Allowance	-
Rate Base	**764,448**
Regulated Rate of Return	5.97%
Regulated Return on Capital	**45,638**
Deemed Interest Expense	18,668
Deemed Return on Equity	26,970
OM&A	-
Depreciation Expense - (50 Yrs, Half Yr)	15,443
Regulated Return on Capital	45,638
	61,081
Pils	(3,551)
Revenue Requirement	57,530
CCA - Class 49 , 8%	61,774
(1,544,339 x 50% x 8%)	
Deemed Return on Equity	26,970
Add Depreciation	15,443
Less CCA	(61,774)
	(19,360)
Pils	(3,001)
Gross Up - Pils	(3,551)

2-Energy Probe-7

Ref: Exhibit 2, Tab 1, Schedule 1, page 13

What is the difference, if any, between Revised CGAAP in 2012, 2013, and 2014 and MIFRS for 2015 and 2016?

Response:

Revised CGAAP reflects the changes to depreciation and capitalization policies and HHH used CGAAP for financial reporting. MIFRS is when HHH has fully converted to IFRS.

2-Energy Probe-8

Ref: Exhibit 2, Tab 1, Schedule 1, Tables 2-18 through 2-22

a) Please explain why there are no disposals shown in any of the tables. How are the removal and/or sale of assets accounted for?

b) Please identify for each of 2012 through 2016 the capital expenditures incurred/forecast for the transformer station. In particular, please show the amounts included in each account for each of 2012 through 2016, or indicate that all expenditures are included in WIP, including the land purchase.

c) Please update Table 2-21 (2015 bridge year) to reflect actual data for 2015. If complete year 2015 data is not yet available, please update Table 2-16 to reflect the most recent year to date actuals available, along with the current estimate for the remaining months of 2015.

d) Please update Table 2-22 (2016 test year) to reflect any changes and/or impacts from the updated forecast of capital additions forecast for the 2015 bridge year.

Response:

a) Assets disposed of are fully depreciated and as such are not reflected on the fixed asset continuity table as they were historically recorded on a pool basis. Any proceeds from disposal are recorded as miscellaneous income.

b) Capital expenditures from 2012 to 2014 for the transformer station are included in WIP. The land purchase for 2015 shown in table 2 – 21 will be moved to WIP and no costs for the transformer station is included 2016 Test year.

c) A revised Table 2- 16, labelled as Table IRR - 19 below, presents HHHI 2015 forecast.

Table IRR - 19 : Revised Fixed Assets – 2015 Bridge Year

			Cost				Accumulated Depreciation				
CCA Class[2]	OEB Account[3]	Description[3]	Opening Balance	Additions[4]	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	2,355,680	54,343		$ 2,410,023	(1,758,375)	(640,615)		-$ 2,398,990	$ 11,033
CEC	1612	Land Rights (Formally known as Account 1906)	4,738			$ 4,738	-	-		$ -	$ 4,738
N/A	1805	Land	591,591	-		$ 591,591	-	-		$ -	$ 591,591
47	1808	Buildings	-	78,423		$ 78,423	-	(64,961)		-$ 64,961	$ 13,462
13	1810	Leasehold Improvements	-	-		$ -	-	-		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	-	(0)		-$ 0	-	-		$ -	-$ 0
47	1820	Distribution Station Equipment <50 kV	5,754,028	41,368		$ 5,795,396	(1,376,207)	(55,576)		-$ 1,431,782	$ 4,363,614
47	1825	Storage Battery Equipment	-	-		$ -	-	-		$ -	$ -
47	1830	Poles, Towers & Fixtures	26,872,181	2,327,870		$ 29,200,050	(13,775,688)	(413,835)		-$ 14,189,523	$ 15,010,527
47	1835	Overhead Conductors & Devices	8,698,625	1,138,923		$ 9,837,548	(1,319,761)	(209,069)		-$ 1,528,830	$ 8,308,718
47	1840	Underground Conduit	1,191,251	282,820		$ 1,474,070	(163,736)	(23,898)		-$ 187,634	$ 1,286,436
47	1845	Underground Conductors & Devices	8,192,213	692,912		$ 8,885,125	(1,338,015)	(289,139)		-$ 1,627,154	$ 7,257,971
47	1850	Line Transformers	10,435,275	197,869		$ 10,633,144	(1,482,190)	(248,860)		-$ 1,731,050	$ 8,902,094
47	1855	Services (Overhead & Underground)	3,054,541	363,490		$ 3,418,031	(418,500)	(4,544)		-$ 423,044	$ 2,994,987
47	1860	Meters	5,390,375	490,319		$ 5,880,694	(794,129)	(157,134)		-$ 951,262	$ 4,929,432
47	1860	Meters (Smart Meters)	-			$ -	-			$ -	$ -
N/A	1905	Land	-	-		$ -	-	-		$ -	$ -
47	1908	Buildings & Fixtures	3,634,056	-		$ 3,634,056	(918,444)	-		-$ 918,444	$ 2,715,611
13	1910	Leasehold Improvements	-	-		$ -	-	-		$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	430,956	77,901		$ 508,856	(318,566)	(33,008)		-$ 351,574	$ 157,282
8	1915	Office Furniture & Equipment (5 years)	-			$ -	-			$ -	$ -
10	1920	Computer Equipment - Hardware	1,543,189	74,759		$ 1,617,948	(1,418,645)	(170,392)		-$ 1,589,037	$ 28,911
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	-			$ -	-			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	-			$ -	-			$ -	$ -
10	1930	Transportation Equipment	3,213,261	290,854		$ 3,504,115	(1,956,298)	(152,240)		-$ 2,108,538	$ 1,395,576
8	1935	Stores Equipment	59,018	-		$ 59,018	(52,043)	-		-$ 52,043	$ 6,975
8	1940	Tools, Shop & Garage Equipment	720,869	-		$ 720,869	(494,282)	(35,302)		-$ 529,585	$ 191,284
8	1945	Measurement & Testing Equipment	-	-		$ -	-	-		$ -	$ -
8	1950	Power Operated Equipment	-	-		$ -	-	-		$ -	$ -
8	1955	Communications Equipment	2,477	5,126		$ 7,603	(65,343)	(4,177)		-$ 69,520	-$ 61,917
8	1955	Communication Equipment (Smart Meters)	-			$ -	-			$ -	$ -
8	1960	Miscellaneous Equipment	-	-		$ -	-	-		$ -	$ -
47	1970	Load Management Controls Customer Premises	734,195	-		$ 734,195	(298,141)	-		-$ 298,141	$ 436,054
47	1975	Load Management Controls Utility Premises	-	-		$ -	-	-		$ -	$ -
47	1980	System Supervisor Equipment	1,140,049	-		$ 1,140,049	(518,212)	-		-$ 518,212	$ 621,837
47	1985	Miscellaneous Fixed Assets	-	-		$ -	-	-		$ -	$ -
47	1990	Other Tangible Property	-	-		$ -	-	-		$ -	$ -
47	1995	Contributions & Grants	(8,449,133)	-		-$ 8,449,133	1,753,072	241,403		$ 1,994,475	-$ 6,454,658
47	2440	Deferred Revenue[5]	-			$ -	-	-		$ -	$ -
			-			$ -	-	-		$ -	$ -
		Sub-Total	$ 75,569,434	$ 6,116,976	$ -	$ 81,686,410	-$ 26,713,502	-$ 2,261,348	$ -	-$ 28,974,850	$ 52,711,559
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	$ 75,569,434	$ 6,116,976	$ -	$ 81,686,410	-$ 26,713,502	-$ 2,261,348	$ -	-$ 28,974,850	$ 52,711,559
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						-$ 2,261,348			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 152,240
Stores Equipment	
Net Depreciation	-$ 2,109,107

d) Based on the 2015 forecast HHHI does not anticipate any significant change to the planned capital expenditures for 2016.

2-Energy Probe-9

Ref: Exhibit 2, Table 2-2, Table 2-22 and RRWF

a) Please explain why Table 2-22 does not show any fully allocated depreciation.

b) Please explain the difference in depreciation expense of $2,530,022 shown in Table 2-22 and the $2,356,422 shown in the RRWF (Revenue Requirement sheet).

c) Please confirm that HHHI has removed this difference in the calculation of the cost of power and controllable expenses used to calculate the working capital as shown Table 2-2.

Response:

a) Table 2 – 22 (presented below as Table IRR - 20) has been updated to show the fully allocated depreciation.

Table IRR - 20 : Revised Appendix 2-BA - Fixed Asset Continuity Schedule 1 as at December 31, 2016 – MIFRS

			Cost				Accumulated Depreciation				
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance	Additions [4]	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	2,441,180	2,800		$ 2,443,980	(2,406,779)	(670,479)		-$ 3,077,259	-$ 633,278
CEC	1612	Land Rights (Formally known as Account 1906)	4,738	-		$ 4,738	-	-		$ -	$ 4,738
N/A	1805	Land	1,524,591	-		$ 1,524,591	-	-		$ -	$ 1,524,591
47	1808	Buildings	-			$ -	-			$ -	$ -
13	1810	Leasehold Improvements	-	-		$ -	-	-		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	-	-		$ -	-	-		$ -	$ -
47	1820	Distribution Station Equipment <50 kV	6,021,473	1,008,609		$ 7,030,082	(1,437,434)	(93,129)		-$ 1,530,563	$ 5,499,518
47	1825	Storage Battery Equipment	-	-		$ -	-	-		$ -	$ -
47	1830	Poles, Towers & Fixtures	29,749,857	3,706,539		$ 33,456,395	(14,195,021)	(485,175)		-$ 14,680,197	$ 18,776,199
47	1835	Overhead Conductors & Devices	9,921,860	1,501,254		$ 11,423,114	(1,529,767)	(240,278)		-$ 1,770,046	$ 9,653,069
47	1840	Underground Conduit	1,555,641	546,812		$ 2,102,453	(188,450)	(33,826)		-$ 222,276	$ 1,880,177
47	1845	Underground Conductors & Devices	8,690,804	208,164		$ 8,898,968	(1,624,528)	(296,064)		-$ 1,920,592	$ 6,978,376
47	1850	Line Transformers	11,229,339	893,285		$ 12,122,624	(1,738,894)	(278,906)		-$ 2,017,801	$ 10,104,823
47	1855	Services (Overhead & Underground)	3,396,804	387,911		$ 3,784,715	(422,778)	(13,405)		-$ 436,184	$ 3,348,531
47	1860	Meters	5,733,561	294,710		$ 6,028,271	(948,963)	(164,802)		-$ 1,113,765	$ 4,914,506
47	1860	Meters (Smart Meters)	-			$ -	-			$ -	$ -
N/A	1905	Land	-	-		$ -	-	-		$ -	$ -
47	1908	Buildings & Fixtures	3,784,056	285,000		$ 4,069,056	(984,258)	(70,992)		-$ 1,055,249	$ 3,013,806
13	1910	Leasehold Improvements	-	-		$ -	-	-		$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	482,092	70,000		$ 552,092	(348,898)	(42,445)		-$ 391,343	$ 160,749
8	1915	Office Furniture & Equipment (5 years)	-			$ -	-			$ -	$ -
10	1920	Computer Equipment - Hardware	1,664,689	75,000		$ 1,739,689	(1,596,827)	(210,932)		-$ 1,807,760	-$ 68,071
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	-			$ -	-			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	-			$ -	-			$ -	$ -
10	1930	Transportation Equipment	3,542,261	145,000		$ 3,687,261	(2,110,128)	(173,580)		-$ 2,283,708	$ 1,403,553
8	1935	Stores Equipment	59,018	-		$ 59,018	(52,043)	-		-$ 52,043	$ 6,975
8	1940	Tools, Shop & Garage Equipment	750,869	32,000		$ 782,869	(531,085)	(39,902)		-$ 570,987	$ 211,882
8	1945	Measurement & Testing Equipment	5,000	-		$ 5,000	-	-		$ -	$ 5,000
8	1950	Power Operated Equipment	-	-		$ -	-	-		$ -	$ -
8	1955	Communications Equipment	9,477	100,000		$ 109,477	(69,708)	(15,065)		-$ 84,772	$ 24,705
8	1955	Communication Equipment (Smart Meters)	-			$ -	-			$ -	$ -
8	1960	Miscellaneous Equipment	-	-		$ -	-	-		$ -	$ -
47	1970	Load Management Controls Customer Premises	734,195	-		$ 734,195	(298,141)	-		-$ 298,141	$ 436,054
47	1975	Load Management Controls Utility Premises	-	-		$ -	-	-		$ -	$ -
47	1980	System Supervisor Equipment	1,433,011	86,579		$ 1,519,590	(518,212)	-		-$ 518,212	$ 1,001,378
47	1985	Miscellaneous Fixed Assets	-	-		$ -	-	-		$ -	$ -
47	1990	Other Tangible Property	-	-		$ -	-	-		$ -	$ -
47	1995	Contributions & Grants	(8,449,133)	-		-$ 8,449,133	1,753,072	-		$ 1,753,072	-$ 6,696,061
47	2440	Deferred Revenue[5]	(1,448,137)	(1,132,703)		-$ 2,580,840	262,091	298,960		$ 561,051	-$ 2,019,789
			-			$ -	-			$ -	$ -
		Sub-Total	**$ 82,837,245**	**$ 8,210,960**	**$ -**	**$ 91,048,205**	**-$ 28,986,751**	**-$ 2,530,022**	**$ -**	**-$ 31,516,773**	**$ 59,531,431**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 82,837,245**	**$ 8,210,960**	**$ -**	**$ 91,048,205**	**-$ 28,986,751**	**-$ 2,530,022**	**$ -**	**-$ 31,516,773**	**$ 59,531,431**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,530,022**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 173,580
Stores Equipment	
Net Depreciation	-$ 2,356,442

b) The difference in depreciation expense of $2,530,022 and $2,356,422 is $173,580 which is the amount for transportation equipment as shown in Table IRR - 20 above.

c) Confirmed.

2-Energy Probe-10

Ref: Exhibit 2, Tab 1, Schedule 1, page 26

Please confirm that the years shown in Table 2-23 are for 2015 and 2016 and not 2014 and 2015 as labeled.

Response:

Confirmed.

2-Energy Probe-11

Ref: Exhibit 2, Tab 1, Schedule 3

Please update the cost of power calculations to reflect the most recent information available, including the Regulated Price Plan Price Report dated October 15, 2015. Please include an updated Table 2-32A and 2-32B.

Response:

Please refer to 2- Staff -5.

2-Energy Probe-12

Ref: Exhibit 2, Tab 2, Schedule 2

a) Please change the "Plan" columns in Table 2-33 to reflect the "Budget" for each year shown. If HHHI does not have historical information for budget amounts broken down into the four categories show, please provide the total budget amount for each year. Please use the Board approved capital expenditures as the 2012 budget.

b) Please update Table 2-33 to reflect the most recent year to date actuals for 2015 along with a current estimate for the remainder of the year if actual expenditures for 2015 are not yet available.

Response:

a) HHHI does not have the historical year's budget broken down in the four OEB categories. A revised Table 2 -33, labelled Table IRR -21 and presented below, shows the total budget for each year.

Table IRR - 21 : Revised Board Appendix 2-AB – Capital Expenditure Summary from DSP Filing Requirements

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2011			2012			2013			2014			2015			2016	2017	2018	2019	2020
	Budget	Actual	Var	OEB Approved	Actual	Var	Budget	Actual	Var	Budget	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access		1,182,087	--		5,251,191	--		1,867,987	--		2,680,732	--	1,578,189		-100.0%	1,339,885	290,760	1,589,978	256,040	256,410
System Renewal		2,316,186	--		2,560,260	--		1,584,398	--		2,362,906	--	1,870,124		-100.0%	3,790,671	4,226,861	2,818,292	4,220,233	5,464,607
System Service		757,210	--		1,192,256	--		1,777,792	--		1,975,057	--	3,485,366		-100.0%	2,302,791	1,854,882	3,535,241	4,567,366	1,856,986
General Plant		865,557	--		1,210,052	--		420,040	--		1,272,141	--	784,136		-100.0%	777,613	479,416	421,000	425,000	374,000
TOTAL EXPENDITURE	6,119,754	5,121,039	-16.3%	6,900,000	10,213,760	48.0%	7,749,967	5,650,217	-27.1%	8,079,799	8,290,836	2.6%	7,717,815	-	-100.0%	8,210,960	6,851,919	8,364,511	9,468,639	7,952,003
System O&M			--			--			--			--			--					

b) A revised Table 2 -33, labelled Table IRR - 22 and presented below, shows HHHI's forecast for 2015.

Table IRR - 22 : Revised Board Appendix 2-AB – Capital Expenditure Summary from DSP Filing Requirements

First year of Forecast Period: 2016

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2011			2012			2013			2014			2015			2016	2017	2018	2019	2020
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	N/A		--	N/A	5,271,277	--	N/A	1,867,987	--	N/A	2,680,732	--	2,329,819	N/A	--	1,339,885	270,760	1,589,978	256,040	256,410
System Renewal	N/A		--	N/A	2,453,195	--	N/A	1,584,398	--	N/A	2,362,906	--	1,870,124	N/A	--	3,790,671	4,226,861	2,818,292	4,220,233	5,464,607
System Service	N/A		--	N/A	1,234,705	--	N/A	1,777,792	--	N/A	1,975,057	--	2,733,736	N/A	--	2,302,791	2,005,288	3,692,810	4,732,097	2,028,880
General Plant	N/A		--	N/A	1,254,582	--	N/A	420,040	--	N/A	1,272,141	--	784,136	N/A	--	777,613	479,416	421,000	425,000	374,000
TOTAL EXPENDITURE	-	-	--	-	10,213,759	--	-	5,650,217	--	-	8,290,836	--	7,717,815	-	-100.0%	8,210,960	6,982,325	8,522,080	9,633,370	8,123,897
System O&M			--			--			--			--			--					

2-Energy Probe-13

Ref: Exhibit 2, Tab 2, Schedules 6 and 7

Will HHHI be applying for an incremental capital module when it forecasts the transformer station to go into service?

Response:

Yes, HHHI will be applying for an incremental capital module upon the commissioning of the transformer station expected in 2018.

2-Energy Probe-14

Ref: Exhibit 2 &
EB-2011-0271 Decision and Order, dated June 14, 2012

At page 7 of the EB-2011-0271 Decision and Order, the Board found that with respect to the cost and benefits of the green energy initiative proposed by HHHI (solar panels on poles) that:

> *"The Board expects that HHH will prepare documentation of its costs, financial benefits and any non-financial benefits. It expects that the documentation will serve to narrow uncertainties on both cost and benefits. The Board expects that the documentation of the pilot will be filed in support of any application that HHH may make at a future time for approval of additional photovoltaic installations. This way the results can be made publicly available and may be useful to other distributors."*

a) Has HHHI prepared any documents of the costs, financial benefits and non-financial benefits associated with the 200 solar panels approved by the Board? If yes, please file all such documents. If not, please explain why not.

b) What is the net book value associated with these panels forecast to be in the 2016 rate base?

c) What is the revenue requirement in 2016 associated with these panels?

d) Please confirm that HHHI did add any solar panels to the 200 approved by the Board since 2012 and that it has no plans to add anymore in 2016. If this cannot be confirmed, please provide details.

Response:

a) HHHI has provided the paper "Distribution System Solar Integration Project", submitted to the LDC Tomorrow Fund in July 2013 and containing an Evaluation Report from Kinetrics Inc found in Appendix IRR - C.

b) The net book value of the panels that is included in 2016 rate base is $165,000.

c) The revenue requirement in 2016 for the solar panel is $17,234.

d) HHHI confirms that it has not added any solar panels to the 200 approved by the Board in 2012 and there are no plans to add any addition panels going forward.

2-SEC-19

Ref: [1/2/1, p. 15]

Please confirm that no part of the land or design costs for the new transformer station are included in rate base for the Test Year.

Response:

Please refer to 2-Energy Probe-8 part (c).

2-SEC-20

Ref: [1/3/4, p. 51]

Please describe the difference between “Feeder Renewal Projects” and “Feeder Upgrade and Reinforcement”.

Response:

Feeder renewal projects (System Renewal) are those where HHHI has identified that assets have reached end of life and require replacement. Feeder upgrade and reinforcement projects (System Service) are projects where the current infrastructure is to be upgraded to accommodate increased load, improved power quality and/or for reliability improvements.

2-SEC-21

Ref: [1/4/1, p. 65]

Please confirm that the Applicant no longer operates any assets on a run to failure basis. If not confirmed, please provide details of all asset classes currently operated on a run to failure basis, and the current schedule for when that operational basis is expected to be changed. Where the operational basis will be changed in the future, please describe for each asset class being changed the new operational basis that will be used, e.g. inspection and testing, scheduled replacement, etc.

Response:

HHHI has not indicated in the application that HHHI no longer operate assets to end of life. The following assets are currently operated to end of life

- Pole mounted transformers except as noted in section 3.4.3 of Engineering Report SP14-03, appendix A of DSP.
- Gang Operated Pole Mount Switch (App. A of DSP, Engineering Report SP14-03, S.3.5.3)
    - Scheduled replacements as needed where automation requirements are identified (technological obsolescence)
- Overhead primary and secondary conductors (App. A of DSP, Engineering Report SP14-03, S.3.7.3)
- Padmounted transformers except as noted in section 4.3.3 of Engineering Report SP14-03, appendix A of DSP.
- Padmounted Switchgear (App. A of DSP, Engineering Report SP14-03, S.4.6.3)
- Underground secondary cable (App. A of DSP, Engineering Report SP14-03, S.4.8.3)
- Primary Metering Units (App. A of DSP, Engineering Report SP14-03, S.7.4.3)
    - Transition from a run to failure basis to proactive replacement strategy for oil filled units within this DSP timeframe. New operational basis will include scheduled replacements of oil filled units based on age and condition of unit.
- Revenue meters including smart meters (App. A of DSP, Engineering Report SP14-03, S.7.3.3 & 7.5.3)

2-SEC-22

Ref: [2/1/1, p. 6]

Please add three rows at the bottom of Table 2-3, and calculate for each year the revenue requirement of the forecast assets to be included in revenue requirement in EB-2011-0271, the revenue requirement of the assets actually placed in service in that year, and the (asymmetrical) amount by which the forecast revenue requirement exceeds the actual revenue requirement.

Response:

Please refer to 2-Energy Probe-6 part (d).

2-SEC-23

Ref: [2/1/1, p. 19, 25]

Please explain how Computer Software, whether in Account 1925 or in Account 1611, can have a negative net book value at the end of the Test Year. Please explain how the depreciation included in rates for the Test Year can exceed the total of the net book value at the beginning of the year, plus the additions during the year.

Response:

HHHI will review Computer Software Account 1920 and Computer Hardware 1925 and update revenue requirement.

2-SEC-24

Ref: [2/2/2, p. 71]

Please confirm that the planned capital additions for Computer Hardware and Computer Software in the Test Year is zero. If the capital additions formerly categorized as such have been changed, and are now categorized in other lines on the table, please map those changes.

Response:

HHHI cannot confirm. Please refer to Exhibit 2, Tab 1, page 19, Table 2-17.

2-VECC-2

Reference: E2/T1/S3, page 43 /EB-2011-0271 E2/T3/S3/pg.3

Pre-amble: HHH provided the following forecasted capital expenditures from its Asset Management plan in its last cost of service application:

Table 2-24: Forecasted Capital Expenditures for 2013

Projects	Estimated
Pole Replacement	$ 417,777
W.C.B - 5 Side Rd to Norval (Construction 2013)	$ 1,116,407
SCADA-Mate Switches (QTY: 3)	$ 171,074
Ewing Street, Georgetown - Aging Pole Line	$ 157,206
Reconductoring WCB from Guelph Street	$ 145,060
27.6kV Conversion Project, 5 Side Road (5th Line	$ 306,271
Tweedle Street	$ 522,386
Pole Trans - Princncess Ann Dr (Gtwn)	

Table 2-25: Forecasted Capital Expenditures for 2014

Projects	Estimated
Pole Replacements - 2014 (Estimated)	$ 425,279
SCADA-Mate Switches (QTY: 2)	$ 128,750
Pole, Conductor, Tx., and Switch Replacements on Church Street	$ 363,998
27.6kV Converson Project, 5 Side Road (6th Line to Trafalgar	$ 268,695
Glen Crescent Rebuild (Glen Williams)	$ 157,781
Pole Trans - Division Rd, Clare St, George St, Rosemary St	$ 577,855

Table 2-26: Forecasted Capital Expenditures for 2015

Projects	Estimated Costs
Pole Replacements - 2015 (Estimated)	$ 438,924
27.6kV Converson Project, 5 Side Road (Trafalgar Road to 9th	$ 539,651
SCADA-Mate Switches (QTY: 2)	$ 133,083
3rd Line South of 22nd Side Road (Acton)	$ 340,374
Wildwood Road Oakridge Construction	
Pole Trans - Acton Blvd, Norman St, McDonald St & Block A	$ 567,050

a) Please provide a variance analysis for these 2012 projections.

Response:

The variance analysis based on HHHI forecasted capital expenditures for 2013, 2014 and 2015 as presented in its 2012 cost of service application is presented below as Table IRR - 23.

Table IRR - 23 : Variance Analysis of Forecasted Capital Expenditures

Table 2-24: Forecasted Capital Expenditures for 2013

Projects	Estimated Costs	Actual Costs	Variance
Pole Replacement	417,777	1,183,227	- 765,450
W.C.B - 5 Side Rd to Norval (Construction 2013)	1,116,407	794	1,115,613
SCADA-Mate Switches (QTY: 3)	171,074	-	171,074
Ewing Street, Georgetown - Aging Pole Line Rehabilitation	157,206	-	157,206
Reconductoring WCB from Guelph Street	145,060	-	145,060
27.6kV Conversion Project, 5 Side Road (5th Line to 6th Line)	306,271	2,103	304,168
Tweedle Street	522,386	331,266	191,120
Pole Trans - Princncess Ann Dr (Gtwn)			-
Total	**2,836,181**	**1,517,390**	**1,318,791**

Table 2-25: Forecasted Capital Expenditures for 2014

Projects	Estimated Costs	Actual Costs	Variance
Pole Replacements - 2014 (Estimated)	425,279	1,908,706	-1,483,427
SCADA-Mate Switches (QTY: 2)	128,750	30,878	97,872
Pole, Conductor, Tx., and Switch Replacements on Church Street East, Acton.	363,998	-	363,998
27.6kV Converson Project, 5 Side Road (6th Line to Trafalgar Road)	268,695	460,730	- 192,035
Glen Crescent Rebuild (Glen Williams)	157,781	-	157,781
Pole Trans - Division Rd, Clare St, George St, Rosemary St (Acton)	577,855	37,729	540,126
Total	**1,922,358**	**2,438,043**	**- 515,685**

Table 2-26: Forecasted Capital Expenditures for 2015

Projects	Estimated Costs	Actual Costs	Variance
Pole Replacements - 2015 (Estimated)	438,924	1,089,938	- 651,014
27.6kV Converson Project, 5 Side Road (Trafalgar Road to 9th Line)	539,651	501,317	38,334
SCADA-Mate Switches (QTY: 2)	133,083	22,676	110,407
3rd Line South of 22nd Side Road (Acton)	340,374	-	340,374
Wildwood Road Oakridge Construction		4,589	- 4,589
Pole Trans - Acton Blvd, Norman St, McDonald St & Block A Reserve (Acton)	567,050	568,730	- 1,680
Total	**2,019,082**	**2,187,250**	**- 168,168**
Total for the 3 years	**6,777,621**	**6,142,683**	**634,938**

2-VECC-3

Reference: E2/T1/S3, page 43

a) Please create a table showing for each year 2015 through 2020 which shows the total forecast capital expenditures for road widening projects; the total expected capital contribution; and the total rate base addition due to these projects.

Response:

Table IRR - 24 shows the forecast capital expenditures for road widening projects; the total expected capital contribution; and the total rate base addition due to these projects from 2015 to 2020.

Table IRR - 24 : Forecasted Capital Expenditures for Road Widening Projects

Project Name	Year of Planned project	Forecast Capital Expenditures	Expected Capital Contributuion	Total Rate Base Addition
Campbellville Road/ Dublin Line Round-About	2015	$70,433	$1,900	$68,533
Steeles Avenue (5th Line South to Trafalgar Road)	2015	$1,956,952	$892,788	$1,064,164
Trafalgar Road/ 10 Side Road (Design Only)	2015	$6,766	$0.00	$6,766
Wildwood Road Relocations (Highway 7 to Oakridge Drive)	2015	$19,603	$10,119	$9,484
MTO 401 Bridge Widening (5th Line South) Relocations	2015	$31,127	$12,712	$18,415
10 Side Road/ 10th Line Round-About Relocations	2015	$18,631	$9,315	$9,316
9th Line (Steelses Avenue to 10Sdrd)	2016	$1,311,549	$480,304	$831,245
Trafalgar Road/ 10 Side Road	2016	$357,295	$103,629	$253,666
Winston Churchill Blvd. (5 Sdrd to Mayfield Rd)	2018	$2,426,000	$1,091,000	$1,335,000

2-VECC-4

Reference: E2/T1/S1, page 18

a) Please explain the $933,000 in land additions in 2015. Specifically has the land been purchased? Is this land being purchased for the transformer station? If yes please explain why the land is proposed to be entered into rate base prior to it being used or useful (i.e. as opposed to CWIP).

Response:

a) The land purchase is for the transformer station. For this application, HHHI will remove the land addition from rate base and Table 2-16: Fixed asset Continuity Schedule as at December 31, 2015.

The land transaction is complete; with a closing transaction date of November 27, 2015.

2-VECC-5

Reference: E2/ DSP/pg.17

a) Halton Hills Hydro notes that it has concerns regarding load growth and single supply reliability to Acton from Fergus TS feeder M4. Are capital expenditures related to this concern incorporated into the 2016-20 DSP? If not please explain why not and provide the estimated costs and timing for addressing these concerns.

Response:

a) Please refer to 2-Staff-11.

2-VECC-6

Reference: E2/ DSP/pgs.34-

a) Please provide a table showing the total population of poles in each of 2012 through 2020.
b) Please provide the number of poles that have been replaced or a forecast to be replaced in each year.
c) Please show the total capital expenditure for (dressed) pole replacement in each year.
d) Please provide the condition of poles by percentage of good, fair, fair-poor, in the last cost of service application, current and the expected or targeted pole condition in 2020.

Response:

a) HHHI's population of poles remain reasonably consistent and is as noted in HHHI's DSP, page 34.

b) HHHI included in its DSP a forecast to replace 275 – 280 poles each year from 2016 to 2020.

c) HHHI estimates that, on average, the capital expenditure for a dressed pole replacement will be approximately $7142.85 based replacing 280 poles per year with a budgeted of $2,000,000 per year.

d) HHHI did not identify specific condition assessments in its last Cost of Service application. HHHI has identified current condition assessment of HHHI poles in Figure 21 "Pole Condition" on page 36 of the DSP. HHHI cannot comment with respect to forecasting pole conditions in 2020 as poles deteriorate over time and HHHI does not have an internal methodology by which to forecast deterioration.

2-VECC-7

Reference: E2/ DSP/pgs.117

a) Please confirm that the table starting at page 88 of the DSP represents the same projects as the summary Table 2-33 at E2/T2/S2.
b) Please revise the table to include the current 2015 actual and year end capital projections.

Response:

a) Confirmed.

b) Please refer to 2-Energy Probe-12 part (b).

2-VECC-8

Reference: **E2/T1/S3, page 43**
Load Forecast Excel Model, Power Purchases Tab, Column C

a) It is noted that HHHI has included the customers' entire load in its cost of power calculations for purposes of determining working capital. However, according to the Load Forecast Model, at least one of HHHI's customers is a Wholesale Market Participant and, therefore, pays the IESO directly for its commodity purchases. Why wasn't this load excluded from the cost of power calculations? Please provide a revised cost of power calculation as required.

Response:

a) HHHI did not exclude the load for this one customer from the cost of power calculation as the amount was immaterial. It is 0.82% of the total load with an impact of approximately $2,000 on working capital.