October 12, 2012

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

Dear Ms. Walli:

Re: 2013 IRM3 Electricity Distribution Rate Application,
Halton Hills Hydro Inc.,
Board File no. EB-2012-0130

Halton Hills Hydro Inc. ("HHHI") is pleased to file its 2013 3rd Generation Incentive Regulation Mechanism ("IRM3") Rate Application with the Ontario Energy Board ("the Board"). HHHI is submitting its 2013 IRM3 Rate Application in accordance with all directives and guidelines issued by the Board. HHHI is requesting an effective date of May 1, 2013 for the implementation of the Proposed 2013 Tariff of Rates and Charges.

The 2013 3rd Generation Incentive Regulation Mechanism Rate Application includes:

- Manager's Summary
- 2013 IRM Rate Generator
- 2013 RTSR Model
- 2013 IRM Revenue to Cost Ratio Adjustment Workform
- 2013 IRM Tax Sharing Model

Please find attached to this cover letter:

- 2 paper copies of the 2013 IRM3 Rate Application; and
- 1 electronic copy of the 2013 IRM3 Rate Application.

A copy of the Application has also been filed through the Web Portal.

In the event of any additional information, questions or concerns, please contact David Smelsky, Chief Financial Officer, at dsmelsky@haltonhillshydro.com or (519) 853-3700 extension 208, or Tracy Rehberg-Rawlingson, Regulatory Affairs Officer, at tracyr@haltonhillshydro.com or (519) 853-3700 extension 257.

Sincerely,

(Original signed)

David J. Smelsky, CMA
Chief Financial Officer, HHHI

Cc: Arthur A. Skidmore, President & CEO, HHHI

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IN THE MATTER OF the *Ontario Energy Board Act,1998*, S.O.1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Halton Hills Hydro Inc. to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other charges for electricity distribution to be effective May 1, 2013.

HALTON HILLS HYDRO INC. ("HHHI")

APPLICATION FOR APPROVAL OF 2013 ELECTRICITY DISTRIBUTION RATES

MANAGER'S SUMMARY

Filed: October, 12, 2012

David J. Smelsky
Chief Financial Officer
Halton Hills Hydro Inc.
43 Alice Street
Halton Hills (Acton), ON
L7J 2A9

Tel: (519) 853-3700 extension 208
dsmelsky@haltonhillshydro.com

APPLICATION FOR APPROVAL OF 2013 ELECTRICITY DISTRIBUTION RATES

MANAGER'S SUMMARY

Introduction

a) The Applicant is Halton Hills Hydro Inc. ("HHHI"). HHHI is a corporation incorporated pursuant to the Ontario Business Corporations Act and located in the Town of Halton Hills (Acton). HHHI carries on the business of distributing electricity within the Municipal boundaries of the Town of Halton Hills.

b) HHHI hereby applies to the Ontario Energy Board ("the Board") pursuant to section 78 of the *Ontario Energy Board Act, 1998* as amended (the "OEB Act") for approval of its proposed distribution rates and other charges, effective May 1, 2013.

c) HHHI is applying for a rate adjustment under the 2013 3rd Generation Incentive Regulation Mechanism ("IRM3").

d) HHHI has followed the Instructions provided in Chapter 3 of the Board's *Filing Requirements for Transmission and Distribution Applications* and revision 4.0 of the Guideline G-2008-0001 - Electricity Distribution Retail Transmission Service Rates issued June 28, 2012.

e) HHHI has completed the 2013 IRM Rate Generator Model and supplementary models as provided by the Board including the 2013 IRM Shared Tax Savings Model, the 2013 IRM Revenue to Cost Ratio Adjustment Workform and the 2013 RTSRModel.

f) HHHI is not applying for a Lost Revenue Adjustment Mechanism ("LRAM") rate rider.

g) HHHI has provided additional information in its 2013 Electricity Distribution Rate Application (the "Application") where HHHI has determined that such information may be useful to the Board.

Notice of Application

HHHI will publish, as in the past, the Notice of Application, as directed by the Board, in the Independent and Free Press, a free publication circulated to each household and business in the Town of Halton Hills. Additionally, HHHI will also publish, as in the past, the Notice of Application, as directed by the Board, in The New Tanner, a free publication circulated weekly to each household in Acton.

Tariff of Rates and Charges

HHHI has provided in Appendix F, a copy of its approved Interim Tariff of Rates and Charges, effective May 1, 2012 and implemented effective July 1, 2012, issued by the Board as Interim Rate Order dated July 4, 2012. On September 20, 2012, the Board Secretary issued a letter to all Licensed Electricity Distributors instructing distributors to reflect an updated province-wide fixed monthly charge of $5.40 per month, related to the microFIT Generator Service Classification, with the implementation of their 2013 IRM Applications. Please let it be noted that the Service Charge for the MicroFIT Generator Service Classification shows the amount of $5.40 in the 2013 IRM Rate Generator Model on “Tab 4. Current Tariff Sheet” instead of the approved $5.25 in the Interim Rate Order issued by the Board on July 4, 2012, so as to reflect the change in the charge on 2013 IRM Rate Generator Model “Tab 11. Proposed Rates”.

Proposed Distribution Rates and Other Charges

1. **Price Cap Adjustment**

   HHHI has applied the Price Cap Index of 0.88%, as provided in the Model, to both the monthly fixed distribution charge and the distribution volumetric rate, net of all adjustments. HHHI understands that the 0.88% Price Cap Index is an estimate for the inflationary adjustment to input prices and may be adjusted accordingly by the Board staff upon publication of the 2012 GDP-IPI by Statistics Canada.

2. **Incremental Capital Module**

   HHHI is not filing for an Incremental Capital Module.

3. **Z-Factor Claim**

   HHHI is not filing for a Z-Factor adjustment.

4. Smart Meter Rate Rider

HHHI was approved for two (2) class specific Smart Meter Rate Riders for Recovery of Residual Historical Smart Meter Costs and Recovery of Stranded Meter Assets, respectively, in the Board's Interim Rate Order in proceeding EB-2011-0271 dated July 4, 2012. HHHI is not proposing any changes to the approved Smart Meter Rate Riders.

5. Low Voltage Cost Recovery

HHHI Low Voltage Service Rate was approved in its 2012 Cost of Service Application. HHHI is not proposing any changes to its current Low Voltage Service Rate for 2013.

Proposed Retail Transmission Service Rates

HHHI has updated the Retail Transmission Service Rates ("RTSR") Model with its 2011 billing determinants, non-loss adjusted, as filed in the 2011 Reporting and Record Keeping Requirements ("RRR") and its 2011 billing detail for wholesale transmission charges. Table 1 shows HHHI's current approved RTSRs and the proposed RTSRs effective May 1, 2013.

Table 1 – Current and Proposed Retail Transmission Service Rates

		2012 Approved		2013 Proposed	
		Network	Connection	Network	Connection
Rate Class	$/Unit	$	$	$	$
Residential - Time of Use	$/kWh	0.0057	0.0045	0.0057	0.0046
General Service Less Than 50 kW	$/kWh	0.0051	0.0042	0.0051	0.0043
General Service 50 to 999 kW	$/kW	2.2257	1.7975	2.2261	1.8336
General Service 1,000 to 4,999 kW - Interval Meters	$/kW	2.2257	1.7975	2.2261	1.8336
Unmetered Scattered Load	$/kWh	0.0051	0.0042	0.0051	0.0043
Sentinel Lighting	$/kW	1.5878	1.2941	1.5881	1.3201
Street Lighting	$/kW	1.5805	1.2676	1.5808	1.2931

HHHI understands that the Uniform Transmission Rates ("UTR") may change effective January 1, 2013 and as such, OEB staff will adjust the 2013 RTSR Model accordingly to reflect the changes.

Cost Allocation

In the Board's Decision (page 18) to HHHI's 2008 Cost of Service Rate Application (EB-2007-0696) shown in its entirety in Appendix F, the Board stated:

> *"The Board is satisfied with Halton Hills' explanation and findings that the arrangement with Hydro One Networks Inc. (HONI) is acceptable for current purposes. The Board notes that this issue has arisen in the context of the Board's work on the design of distribution rates. The Board expects Halton Hills to keep itself informed as to potential developments through that process. The board also expects Halton Hills to reflect this change in its future cost allocation filings"*

Further, in Board Staff Interrogatory #38 (c) of HHHI's 2012 Cost of Service Rate Application, EB-2011-0271 and shown in Appendix G, submitted November 16, 2011, Board Staff asked:

> *"[If] HHHI continues to deliver power to Hydro One, does HHHI have a proposal that future treatment of Hydro One as an embedded distributor that would be consistent with changes in the Board's cost allocation policy at p. 32 of the referenced Report?"*

HHHI responded:

> *"HHHI will be making an application in 2013 to treat of Hydro One as an embedded distributor that would be consistent with changes in the Board's cost allocation policy at p. 32 of the referenced Report"*

At this time, HHHI is not making application to establish a separate rate class for its embedded distributor for the following reasons:

(i) As per page 32 in the Report of the Board for proceeding EB-2010-0219 - Review of Electricity Distribution Cost Allocation Policy (see Appendix H), the Board states:

> *"The Board is of the view that it is generally appropriate for any distributor with total embedded distributor load that exceeds (a) defined threshold(s) to treat its embedded distributor(s) as a separate customer class.*
>
> *The Board accepts the view of several stakeholders that more analysis regarding the appropriate threshold(s) is required prior to adopting (a) specific percentage of load or aggregate demand threshold(s). The Board believes that this further analysis will require the collection of additional data on embedded loads from distributors… [u]pon review and analysis of this information, the Board will determine what the threshold(s) should be. The*

Board expects that any threshold it will determine will be considered in cost of service applications starting with the 2013 rate year."

The Board has not yet defined the thresholds. Hence, it would be premature for HHHI to create a separate customer class of Embedded Distributor without the thresholds.

(ii) Chapter 3 of the Filing Requirements for Electricity Transmission and Distribution Applications revised June 28, 2012 and shown in Appendix I, the Board states on page 20:

"The IRM application process is intended to streamline the processing of a large volume of rate adjustment applications, and is therefore intended to be mechanistic in nature. For this reason, the Board has determined that the IRM process is not the appropriate venue by which a distributor should seek relief on issues which are substantially unique to an individual distributor or more complicated and potentially contentious. The following are examples of specific exclusions from the IRM rate application process:

- *Rate Harmonization, other than that pursuant to a prior Board decision;*
- ***Changes to revenue-to-cost ratios, other than pursuant to a prior Board decision (emphasis added)****;*
- *Loss Factor Changes;*
- *Re-setting of Specific Service Charges;*
- *Loss Carry Forward Adjustments to PILs/taxes; and*
- *Loss of Customer Load.*

Exclusions from the IRM process are to be addressed in the distributor's next cost of service application"

Hence, in abiding by the Filing Requirements, HHHI has not made changes to cost allocation.

HHHI will continue to include the above referenced HONI account in the General Service 1,000-4,999 kW class and continue to include the account load into the forecast for the General Service 1,000-4,999 kW class for the purpose of cost allocation until explicitly instructed to create the Embedded Distributor class by the Board.

Revenue to Cost Ratio Adjustment

There are no adjustments to the existing revenue to cost ratios as approved in HHHI's 2012 Cost of Service Rate Application (EB-2011-0271). All rate classes remain within the acceptable ranges.

Proposed Deferral and Variance Account Disposition

HHHI has completed the Deferral and Variance Account continuity schedule included in the 2013 IRM Rate Generator Model at "Tab 5. 2013 Continuity Schedule" for its Group 1 Deferral and Variance Accounts. The entire Continuity Schedule can be seen in Appendix A. HHHI has not included Recovery of Regulatory Asset Balances-Disposition and Recovery/Refund of Regulatory Balances (2010) as disposition is requested on balances ending December 31, 2011 and the 2010 balances were charged until April 30, 2012. HHHI will request disposition of the 2010 balances with the next rate application.

HHHI confirms that all year end balances agree with its annual filings required under the RRRs and also agree with HHHI's annual audited financial statements. HHHI filed a Cost of Service Rate Application EB-2011-0271 for rates effective May 1, 2012 which included the disposition of its December 31, 2010 Deferral and Variance Account balances and as such, the continuity schedule begins with the 2010 closing balances. Approved disposition amounts from the Cost of Service Rate Application are included in the 2012 section of the continuity schedule.

In all cases, the principal and carrying charges as at December 31, 2011, adjusted for 2012 approved disposition amounts, have been included separately and projected to April 30, 2013 in the final continuity schedule at interest rates consistent with the Board's prescribed rates. The prescribed interest rate for the four quarters of 2012 has remained constant at 1.47%. The interest rate of 1.47% was also used for 2013 and averaged over the four months January to April.

The Group 1 Deferral and Variance Account balance totals ($87,049), including projected interest, calculated to April 30, 2013. Table 2 shows the amounts by USoA.

Table 2 – Group 1 Deferral and Variance Account for disposition in 2013 IRM Application

Account Descriptions	Account Number	Closing Principal Balance as of Dec-31-11	Closing Interest Amounts as of Dec-31-11	Principal Disposition during 2012 - instructed by Board	Interest Disposition during 2012 - instructed by Board	Closing Principal Balances as of Dec 31-11 Adjusted for Dispositions during 2012	Closing Interest Balances as of Dec 31-11 Adjusted for Dispositions during 2012	Projected Interest from Jan 1, 2012 to December 31, 2012 on Dec 31 -11 balance adjusted for disposition during 2012	Projected Interest from January 1, 2013 to April 30, 2013 on Dec 31 -11 balance adjusted for disposition during 2012	Total Claim
Group 1 Accounts										
LV Variance Account	**1550**	(637,786)	(12,194)	(613,274)	(13,534)	(24,512)	1,340	(360)	(120)	(23,652)
RSVA - Wholesale Market Service Charge	**1580**	(975,680)	(131,228)	(503,791)	(130,003)	(471,889)	(1,225)	(6,937)	(2,312)	(482,363)
RSVA - Retail Transmission Network Charge	**1584**	899,985	(241,525)	601,339	(238,494)	298,646	(3,031)	4,390	1,463	301,468
RSVA - Retail Transmission Connection Charge	**1586**	640,117	(189,808)	517,827	(186,920)	122,290	(2,888)	1,798	599	121,799
RSVA - Power (excluding Global Adjustment)	**1588**	(1,590,500)	(460,889)	(473,530)	(440,300)	(1,116,970)	(20,589)	(16,419)	(5,473)	(1,159,452)
RSVA - Power - Sub-account - Global Adjustment	**1588**	3,339,708	58,964	2,249,396	54,258	1,090,312	4,706	16,028	5,343	1,116,388
Recovery of Regulatory Asset Balances	**1590**	(48,639)	116,338	(48,428)	116,101	(211)	237	(3)	(1)	22
Disposition and Recovery/Refund of Regulatory Balances (2008)	**1595**	26,987	11,225			26,987	11,225	397	132	38,741
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		1,654,192	(849,117)	1,729,539	(838,892)	(75,347)	(10,225)	(1,108)	(369)	(87,049)
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		(1,685,516)	(908,081)	(519,857)	(893,150)	(1,165,659)	(14,931)	(17,135)	(5,712)	(1,203,437)

Based on the Threshold Test calculation outlined in the EDDVAR Report, the Group 1 Deferral and Variance Account balances equates to ($0.0002) per kWh, as calculated in "Tab 6. Billing Det.For Def-Var" of the 2013 IRM Rate Generator Model. The Threshold for disposition is $0.001 per kWh and as such, HHHI's Group 1 Deferral and Variance Account balance is not eligible for disposition.

Tax Changes

HHHI is not aware of any changes to the tax legislation since filing its 2012 Cost of Service Rate Application that would result in any tax savings. Therefore, HHHI is not proposing any shared tax savings. Appendix D shows HHHI's completed 2013 IRM Tax Sharing Model.

Specific Service Charges

HHHI has not proposed any changes to its specific service charges. All current Specific Service Charges are consistent with the 2006 Electricity Distribution Rate Handbook issued May 11, 2005, Chapter 11, Other Regulated Charges and HHHI's 2012 Tariff of Rates and Charges.

Proposed Distribution Rates and Other Charges

HHHI has attached its proposed Tariff of Rates and Charges, to be effective May 1, 2013 and shown in Appendix K.

Bill Impacts

HHHI has calculated the customer total bill impact using the results from the 2013 IRM Rate Generator Model. For the typical Residential customer using 800 kWhs per month, the proposed total bill impact will result in an increase of $0.42 or 0.37% on the total monthly bill. For the typical General Service less than 50 kW customer using 2,000kWhs per month, the proposed total bill impact will result in an increase of $1.22 or 0.46% on the total monthly bill.

Total bill impacts based on the proposed rates, for all rate classes, are shown in Table 5.

Table 5 – Proposed Total Bill Impacts by Rate Class

Rate Class	Volumes		% Change
Residential - Time of Use			
	800 kWhs RPP	Tier	0.37%
	800 kWhs RPP	TOU	0.37%
General Service Less Than 50 kW			
	2000 kWhs RPP	Tier	0.44%
	2000 kWhs RPP	TOU	0.46%
General Service 50 to 999 kW			
	100,000kWhs/500kW		0.70%
	200,000kWhs/750kW		0.65%
General Service 1,000 to 4,999 kW - Interval Meters			
	500,000kWhs/1,000kW		1.13%
	1,000,000kWhs/2,500kW		1.89%
Unmetered Scattered Load			
	100kWhs	Tier	8.63%
Sentinel Lighting			
	10kWhs/1kW	Tier	-3.98%
Street Lighting			
	200,000kWhs/641kW		2.10%

IRM3 Models and Supplementary Work Forms

HHHI has completed the most current versions of the 2013 IRM3 models and provided both a hard copy and a live Excel 2003 version of each model as follows:

- 2013_IRM_Rate_Generator_V2.3_20120724 as Appendix A
- 2013 RTSR MODEL_V3_20120628 as Appendix B
- 2013_IRM_Revenue_CostRatioAdj_Workform_V2_20120628 as Appendix C
- 2013_IRM_Tax_Sharing_Model_V1_20120706 as Appendix D

Conclusion

HHHI respectfully submits that it has complied with the Board's Chapter 3 of the Filing Requirements for Transmission and Distribution Applications issued June 28, 2012.

The proposed rates for the distribution of electricity reflect HHHI's 2012 distribution rates, adjusted for a Price Cap Index of 0.88%.

HHHIs Retail Transmission Service Rates have been calculated in accordance with the Electricity Distribution Retail Transmission Service Rates Guideline G-2008-0001, Revision 3.0 dated June 22, 2011 and the 2013 RTSR MODEL_V3_20120628.

HHHI has calculated the Tax Saving to be shared with customers in accordance with the 2013_IRM_Tax_Sharing_Model_V1_20120706 .

In accordance with the Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative ("the EDDVAR Report") issued July 31, 2009, HHHI's total Group 1 Deferral and Variance Accounts do not meet the Threshold Test of $0.001 per kWh and therefore is not eligible for disposition.

HHHI's Specific Service Charges are consistent with those previously approved by the Board in HHHI's 2012 Tariff of Rates and. The Specific Service Charges are consistent with the 2006 Electricity Distribution Rate Handbook issued May 11, 2005, Chapter 11, Other Regulated Charges and HHHI's 2012 Tariff of Rates and Charges.

Relief Sought

HHHI is making an Application for an Order or Orders approving the following:

- The proposed distribution rates and other charges set out in Appendix K to the Application as just and reasonable rates and charges pursuant to Section 78 of the OEB Act, to be effective May 1, 2013.

Form of Hearing Requested

HHHI requests that this Application be disposed of by way of a written hearing.

Respectfully submitted this 12th day of October 2012.

(Original Signed)

David J. Smelsky
Chief Financial Officer
Halton Hills Hydro Inc.

Attachments

Appendix A	2013_IRM_Rate_Generator_V2.3_20120724
Appendix B	2013 RTSR MODEL_V3_20120628
Appendix C	2013_IRM_Revenue_CostRatioAdj_Workform_V2_20120628
Appendix D	2013_IRM_Tax_Sharing_Model_V1_20120706
Appendix E	Interim Tariff of Rates and Charges effective May 1, 2012 (EB-2011-0271)
Appendix F	Board Decision in HHHI's 2008 Cost of Service Application (EB-2007-0696)
Appendix G	Board Staff Interrogatories and HHHI Responses in HHHI's 2012 Cost of Service Application (EB-2011-0271)
Appendix H	Report of the Board EB-2010-0219-Review of Electricity Distribution Cost Allocation Policy
Appendix I	Chapter 3 – Filing Requirements for Electricity Transmission and Distribution Applications – revised June 28, 2012
Appendix J	Proposed Tariff of Rates and Charges to be effective May 1, 2013
Appendix K	Proposed Bill Impacts

Appendix A

2013_IRM_Rate_Generator_V2.3_20120724

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3RD Generation Incentive Regulation Model for 2013 Filers

Version 2.3

Utility Name	Halton Hills Hydro Inc.
Service Territory	*(if applicable)*
Assigned EB Number	EB-2012-0130
Name of Contact and Title	Mr. David J. Smelsky, Chief Financial Officer
Phone Number	519-853-3700 ext 208
Email Address	dsmelsky@haltonhillshydro.com
We are applying for rates effective	Wednesday, May 01, 2013

Notes

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

White cells contain fixed values, automatically generated values or formulae.

3RD Generation Incentive Regulation Model for 2013 Filers

Halton Hills Hydro Inc.

3RD Generation Incentive Regulation Model for 2013 Filers

Halton Hills Hydro Inc.

Select the appropriate rate classes as they appear on your most recent Board-Approved Tariff of Rates and Charges, including the MicroFit Class.

How many classes are listed on your most recent Board-Approved Tariff of Rates and Charges? 8

Select Your Rate Classes from the **Blue Cells** below. Please ensure that a rate class is assigned to **each shaded cell.**

	Rate Class Classification
1	Residential - Time of Use
2	General Service Less Than 50 kW
3	General Service 50 to 999 kW
4	General Service 1,000 to 4,999 kW - Interval Meters
5	Unmetered Scattered Load
6	Sentinel Lighting
7	Street Lighting
8	MicroFit

3RD Generation Incentive Regulation Model for 2013 Filers

Halton Hills Hydro Inc.

For each class, Applicants are required to copy and paste the class descriptions (located directly under the class name) and the description of the applicability of those rates (description is found under the class name and directly under the word "APPLICATION"). By using the drop-down lists located under the column labeled "Rate Description", please select the descriptions of the rates and charges that **BEST MATCHES** the descriptions on your most recent Board-Approved Tariff of Rates and Charges. If the description is not found in the drop-down list, please enter the description in the green cells under the correct class exactly as it appears on the tariff. Please do not enter more than one "Service Charge" for each class for which a base monthly fixed charge applies. **Note: If the current RRRP consists of only one line on the current tariff schedule, enter the same rate for "Rural Rate Protection Charge - effective until April 30, 2012" and "Rural Rate Protection Charge - effective on and after May 1, 2012".

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES

Residential - Time of Use Service Classification

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. The customer will be supplied at one service entrance only. Further servicing details are available in the distributor’s Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.
It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component **(If applicable, Effective Date MUST be included in rate description)**

Service Charge	$	12.25
Distribution Volumetric Rate	$/kWh	0.0115
Low Voltage Service Rate	$/kWh	0.0012
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	0.0012
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kWh	(0.0018)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery (2012) – Effective until April 30, 2014	$/kWh	0.0007
Retail Transmission Rate - Network Service Rate	$/kWh	0.0057
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0045
Rate Rider for Recovery of Foregone Revenue - effective July 1, 2012 - April 30, 2013	$	(0.14)
Rate Rider for Recovery of Foregone Revenue - effective July 1, 2012 - April 30, 2013	$/kWh	(0.0001)
Rate Rider for Recovery of Residual Historical Smart Meter Costs - effective July 1, 2012 - April 30, 2016	$	1.31
Rate Rider for Recovery of Stranded Meter Assets - effective July 1, 2012 - April 30, 2016	$	1.13

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge - effective until April 30, 2012	$/kWh	0.0013
Rural Rate Protection Charge - effective on and after May 1, 2012	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW Service Classification

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component **(If applicable, Effective Date MUST be included in rate description)**

Service Charge	$	26.50
Distribution Volumetric Rate	$/kWh	0.0083
Low Voltage Service Rate	$/kWh	0.0011
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kWh	(0.0018)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery (2012) – Effective until April 30, 2014	$/kWh	0.0007
Retail Transmission Rate - Network Service Rate	$/kWh	0.0051
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0042
Rate Rider for Recovery of Foregone Revenue - effective July 1, 2012 - April 30, 2013	$	(0.3600)
Rate Rider for Recovery of Foregone Revenue - effective July 1, 2012 - April 30, 2013	$/kWh	(0.0001)
Rate Rider for Recovery of Residual Historical Smart Meter Costs - effective July 1, 2012 - April 30, 2016	$	1.3800
Rate Rider for Recovery of Stranded Meter Assets - effective July 1, 2012 - April 30, 2016	$	1.4600

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge - effective until April 30, 2012	$/kWh	0.0013
Rural Rate Protection Charge - effective on and after May 1, 2012	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

General Service 50 to 999 kW Service Classification

This classification applies to a non-residential customer with an average peak demand equal to or greater than 50 kW over the past twelve months, or is forecast to be equal to or greater than 50 kW, but less than 1,000 kW. For a new customer without prior billing history, the peak demand will be based on 90% of the proposed capacity or installed transformer. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component **(If applicable, Effective Date MUST be included in rate description)**

Service Charge	$	74.64
Distribution Volumetric Rate	$/kW	3.3287
Low Voltage Service Rate	$/kW	0.4734
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	1.5817
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kW	(0.7063)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery (2012) – Effective until April 30, 2014	$/kW	0.0490
Retail Transmission Rate - Network Service Rate	$/kW	2.2257
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7975
Rate Rider for Recovery of Foregone Revenue - effective July 1, 2012 - April 30, 2013	$	(0.31)
Rate Rider for Recovery of Foregone Revenue - effective July 1, 2012 - April 30, 2013	$/kW	(0.0130)

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge - effective until April 30, 2012	$/kWh	0.0013
Rural Rate Protection Charge - effective on and after May 1, 2012	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

General Service 1,000 to 4,999 kW - Interval Meters Service Classification

This classification applies to a non-residential customer with an average peak demand equal to or greater than 1,000 kW over the past twelve months, or is forecast to be equal to or greater than 1,000 kW, but less than 5,000 kW. For a new customer without prior billing history, the peak demand will be based on 90% of the installed transformer. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component **(If applicable, Effective Date MUST be included in rate description)**

Service Charge	$	173.31
Distribution Volumetric Rate	$/kW	3.0517
Low Voltage Service Rate	$/kW	0.4734
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	1.9530
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kW	(0.7409)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery (2012) – Effective until April 30, 2014	$/kW	0.0108
Retail Transmission Rate - Network Service Rate	$/kW	2.2257
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7975
Rate Rider for Recovery of Foregone Revenue - effective July 1, 2012 - April 30, 2013	$/kW	(0.1108)

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge - effective until April 30, 2012	$/kWh	0.0013
Rural Rate Protection Charge - effective on and after May 1, 2012	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load Service Classification

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, pedestrian X-Walk signals/beacons, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component **(If applicable, Effective Date MUST be included in rate description)**

Service Charge	$	6.50
Distribution Volumetric Rate	$/kWh	0.0043
Low Voltage Service Rate	$/kWh	0.0011
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	0.0053
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kWh	(0.0016)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0051
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0042
Rate Rider for Recovery of Foregone Revenue - effective July 1, 2012 - April 30, 2013	$	(1.24)
Rate Rider for Recovery of Foregone Revenue - effective July 1, 2012 - April 30, 2013	$/kWh	(0.0008)

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge - effective until April 30, 2012	$/kWh	0.0013
Rural Rate Protection Charge - effective on and after May 1, 2012	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Sentinel Lighting Service Classification

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor’s Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component **(If applicable, Effective Date MUST be included in rate description)**

Service Charge (per connection)	$	4.88
Distribution Volumetric Rate	$/kW	18.4557
Low Voltage Service Rate	$/kW	0.3408
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	18.2482
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kW	(0.7438)
Retail Transmission Rate - Network Service Rate	$/kW	1.5878
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.2941
Rate Rider for Recovery of Foregone Revenue - effective July 1, 2012 - April 30, 2013	$	0.44
Rate Rider for Recovery of Foregone Revenue - effective July 1, 2012 - April 30, 2013	$/kW	1.6698

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge - effective until April 30, 2012	$/kWh	0.0013
Rural Rate Protection Charge - effective on and after May 1, 2012	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Street Lighting Service Classification

All services supplied to street lighting equipment owned by or operated for the Municipality, the Region or the Province of Ontario shall be classified as Street Lighting Service. Street Lighting plant, facilities, or equipment owned by the customer are subject to the Electrical Safety Authority (ESA) requirements and Halton Hills Hydro specifications. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.
It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component **(If applicable, Effective Date MUST be included in rate description)**

Service Charge (per connection)	$	2.14
Distribution Volumetric Rate	$/kW	28.9538
Low Voltage Service Rate	$/kW	0.3338
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	0.2586
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kW	(0.0754)
Retail Transmission Rate - Network Service Rate	$/kW	1.5805
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.2676
Rate Rider for Recovery of Foregone Revenue - effective July 1, 2012 - April 30, 2013	$	(0.03)
Rate Rider for Recovery of Foregone Revenue - effective July 1, 2012 - April 30, 2013	$/kW	(0.4379)

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge - effective until April 30, 2012	$/kWh	0.0013
Rural Rate Protection Charge - effective on and after May 1, 2012	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.2500

MicroFit Service Classification

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component (If applicable, Effective Date MUST be included in rate description)

Service Charge	$	5.40

Please complete the following continuity schedule for the following Deferral / Variance Accounts. Enter information into green cells only.

If you have received approval to dispose of balances from prior years, the starting point for entries in the 2013 DVA schedule below will be the balance sheet date as per your G/L for which you received approval. For example, if in the 2012 EDR process (CoS or IRM) you received approval for the December 31, 2010 balances, the starting point for your entries below should be the adjustment column BF for principal and column BK for interest. This will allow for the correct starting point for the 2011 opening balance columns (for both principal and interest) without requiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

Please refer to the footnotes for further instructions.

		2005									
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-05	Transactions Debit / (Credit) during 2005 excluding interest and adjustments [2]	Board-Approved Disposition during 2005	Adjustments during 2005 - other [2]	Closing Principal Balance as of Dec-31-05	Opening Interest Amounts as of Jan-1-05	Interest Jan-1 to Dec-31-05	Board-Approved Disposition during 2005	Adjustments during 2005 - other [2]	Closing Interest Amounts as of Dec-31-05
Group 1 Accounts											
LV Variance Account	1550					0					0
RSVA - Wholesale Market Service Charge	1580					0					0
RSVA - Retail Transmission Network Charge	1584					0					0
RSVA - Retail Transmission Connection Charge	1586					0					0
RSVA - Power (excluding Global Adjustment)	1588					0					0
RSVA - Power - Sub-account - Global Adjustment	1588					0					0
Recovery of Regulatory Asset Balances	1590					0					0
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	1595					0					0
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	1595					0					0
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	1595					0					0
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		0	0	0	0	0	0	0	0	0	0
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		0	0	0	0	0	0	0	0	0	0
RSVA - Power - Sub-account - Global Adjustment	**1588**	0	0	0	0	0	0	0	0	0	0
Deferred Payments in Lieu of Taxes	1562					0					0
Total of Group 1 and Account 1562		0	0	0	0	0	0	0	0	0	0
Special Purpose Charge Assessment Variance Account[4]	**1521**										
LRAM Variance Account	**1568**										
Total including Accounts 1562, 1521 and 1568		0	0	0	0	0	0	0	0	0	0

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

1 Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

2 For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year.

3 If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December 31, 2012 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded from January 1, 2012 to April 30, 2013 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision.

4 Applicants that did not have the balance in Account 1521 cleared by the Board in the 2012 rate proceedings are expected to file to dispose of Account 1521 in the 2013 rate proceedings. No Account 1521 balance is to be filed for clearance in the 2013 rate proceedings for those distributors that had account 1521 cleared by the Board in the 2012 rate proceedings.

In accordance with section 8 of the Special Purpose Charge ("SPC") Regulation, Ontario Regulation 66/10, distributors were required to apply to the Board no later than April 15, 2012 for an order authorizing the distributor to clear the balance in Account 1521. As per the Board's April 23, 2010 letter, the Board stated that it expected that requests for disposition of the balance in Account 1521 were to be addressed as part of the proceedings to set rates for the 2012 rate year, except in cases where this approach would result in non-compliance with the timeline set out in section 8 of the SPC Regulation.

5 Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund) period has been completed. If the recovery (or refund) period has not been completed, do not include the respective balance in Account 1595 for disposition at this time.

Please complete the following continuity schedule for the following Deferral / Variance Accounts. Enter information into green cells only.

If you have received approval to dispose of balances from prior years, the starting point for entries in the 2013 DVA schedule below will be the balance sheet date as per your G/L for which you received approval. For example, if in the 2012 EDR process (CoS or IRM) you received approval for the December 31, 2010 balances, the starting point for your entries below should be the adjustment column BF for principal and column BK for interest. This will allow for the correct starting point for the 2011 opening balance columns (for both principal and interest) without requiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

Please refer to the footnotes for further instructions.

		2006									
Account Descriptions	**Account Number**	Opening Principal Amounts as of Jan-1-06	Transactions Debit / (Credit) during 2006 excluding interest and adjustments [2]	Board-Approved Disposition during 2006	Adjustments during 2006 - other [2]	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec-31-06	Board-Approved Disposition during 2006 [1]	Adjustments during 2006 - other [2]	Closing Interest Amounts as of Dec-31-06
Group 1 Accounts											
LV Variance Account	1550	0				0	0				0
RSVA - Wholesale Market Service Charge	1580	0				0	0				0
RSVA - Retail Transmission Network Charge	1584	0				0	0				0
RSVA - Retail Transmission Connection Charge	1586	0				0	0				0
RSVA - Power (excluding Global Adjustment)	1588	0				0	0				0
RSVA - Power - Sub-account - Global Adjustment	1588	0				0	0				0
Recovery of Regulatory Asset Balances	1590	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	1595	0				0	0				0
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		0	0	0	0	0	0	0	0	0	0
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		0	0	0	0	0	0	0	0	0	0
RSVA - Power - Sub-account - Global Adjustment	**1588**	0	0	0	0	0	0	0	0	0	0
Deferred Payments in Lieu of Taxes	1562	0				0	0				0
Total of Group 1 and Account 1562		0	0	0	0	0	0	0	0	0	0
Special Purpose Charge Assessment Variance Account[4]	**1521**										
LRAM Variance Account	**1568**										
Total including Accounts 1562, 1521 and 1568		0	0	0	0	0	0	0	0	0	0

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year.
If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December 31, 2012 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded from January 1, 2012 to April 30, 2013 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision.

Applicants that did not have the balance in Account 1521 cleared by the Board in the 2012 rate proceedings are expected to file to dispose of Account 1521 in the 2013 rate proceedings. No Account 1521 balance is to be filed for clearance in the 2013 rate proceedings for those distributors that had account 1521 cleared by the Board in the 2012 rate proceedings.

In accordance with section 8 of the Special Purpose Charge ("SPC") Regulation, Ontario Regulation 66/10, distributors were required to apply to the Board no later than April 15, 2012 for an order authorizing the distributor to clear the balance in Account 1521. As per the Board's April 23, 2010 letter, the Board stated that it expected that requests for disposition of the balance in Account 1521 were to be addressed as part of the proceedings to set rates for the 2012 rate year, except in cases where this approach would result in non-compliance with the timeline set out in section 8 of the SPC Regulation.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund) period has been completed. If the recovery (or refund) period has not been completed, do not include the respective balance in Account 1595 for disposition at this time.

Please complete the following continuity schedule for the following Deferral / Variance Accounts. Enter information into green cells only.

If you have received approval to dispose of balances from prior years, the starting point for entries in the 2013 DVA schedule below will be the balance sheet date as per your G/L for which you received approval. For example, if in the 2012 EDR process (CoS or IRM) you received approval for the December 31, 2010 balances, the starting point for your entries below should be the adjustment column BF for principal and column BK for interest. This will allow for the correct starting point for the 2011 opening balance columns (for both principal and interest) without requiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

Please refer to the footnotes for further instructions.

Account Descriptions	Account Number	2007									
		Opening Principal Amounts as of Jan-1-07	Transactions Debit / (Credit) during 2007 excluding interest and adjustments [2]	Board-Approved Disposition during 2007	Adjustments during 2007 - other [1]	Closing Principal Balance as of Dec-31-07	Opening Interest Amounts as of Jan-1-07	Interest Jan-1 to Dec-31-07	Board-Approved Disposition during 2007	Adjustments during 2007 - other [1]	Closing Interest Amounts as of Dec-31-07
Group 1 Accounts											
LV Variance Account	1550	0				0	0				0
RSVA - Wholesale Market Service Charge	1580	0				0	0				0
RSVA - Retail Transmission Network Charge	1584	0				0	0				0
RSVA - Retail Transmission Connection Charge	1586	0				0	0				0
RSVA - Power (excluding Global Adjustment)	1588	0				0	0				0
RSVA - Power - Sub-account - Global Adjustment	1588	0				0	0				0
Recovery of Regulatory Asset Balances	1590	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	1595	0				0	0				0
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		0	0	0	0	0	0	0	0	0	0
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		0	0	0	0	0	0	0	0	0	0
RSVA - Power - Sub-account - Global Adjustment	**1588**	0	0	0	0	0	0	0	0	0	0
Deferred Payments in Lieu of Taxes	1562	0				0	0				0
Total of Group 1 and Account 1562		0	0	0	0	0	0	0	0	0	0
Special Purpose Charge Assessment Variance Account[4]	**1521**										
LRAM Variance Account	**1568**										
Total including Accounts 1562, 1521 and 1568		0	0	0	0	0	0	0	0	0	0

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year.

If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December 31, 2012 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded from January 1, 2012 to April 30, 2013 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision.

Applicants that did not have the balance in Account 1521 cleared by the Board in the 2012 rate proceedings are expected to file to dispose of Account 1521 in the 2013 rate proceedings. No Account 1521 balance is to be filed for clearance in the 2013 rate proceedings for those distributors that had account 1521 cleared by the Board in the 2012 rate proceedings.

In accordance with section 8 of the Special Purpose Charge ("SPC") Regulation, Ontario Regulation 66/10, distributors were required to apply to the Board no later than April 15, 2012 for an order authorizing the distributor to clear the balance in Account 1521. As per the Board's April 23, 2010 letter, the Board stated that it expected that requests for disposition of the balance in Account 1521 were to be addressed as part of the proceedings to set rates for the 2012 rate year, except in cases where this approach would result in non-compliance with the timeline set out in section 8 of the SPC Regulation.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund) period has been completed. If the recovery (or refund) period has not been completed, do not include the respective balance in Account 1595 for disposition at this time.

Please complete the following continuity schedule for the following Deferral / Variance Accounts. Enter information into green cells only.

If you have received approval to dispose of balances from prior years, the starting point for entries in the 2013 DVA schedule below will be the balance sheet date as per your G/L for which you received approval. For example, if in the 2012 EDR process (CoS or IRM) you received approval for the December 31, 2010 balances, the starting point for your entries below should be the adjustment column BF for principal and column BK for interest. This will allow for the correct starting point for the 2011 opening balance columns (for both principal and interest) without requiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

Please refer to the footnotes for further instructions.

		2008									
Account Descriptions	**Account Number**	**Opening Principal Amounts as of Jan-1-08**	**Transactions Debit / (Credit) during 2008 excluding interest and adjustments [2]**	**Board-Approved Disposition during 2008**	**Adjustments during 2008 - other [1]**	**Closing Principal Balance as of Dec-31-08**	**Opening Interest Amounts as of Jan-1-08**	**Interest Jan-1 to Dec-31-08**	**Board-Approved Disposition during 2008**	**Adjustments during 2008 - other [1]**	**Closing Interest Amounts as of Dec-31-08**
Group 1 Accounts											
LV Variance Account	1550	0				0	0				0
RSVA - Wholesale Market Service Charge	1580	0				0	0				0
RSVA - Retail Transmission Network Charge	1584	0				0	0				0
RSVA - Retail Transmission Connection Charge	1586	0				0	0				0
RSVA - Power (excluding Global Adjustment)	1588	0				0	0				0
RSVA - Power - Sub-account - Global Adjustment	1588	0				0	0				0
Recovery of Regulatory Asset Balances	1590	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	1595	0				0	0				0
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		0	0	0	0	0	0	0	0	0	0
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		0	0	0	0	0	0	0	0	0	0
RSVA - Power - Sub-account - Global Adjustment	**1588**	0	0	0	0	0	0	0	0	0	0
Deferred Payments in Lieu of Taxes	1562	0				0	0				0
Total of Group 1 and Account 1562		0	0	0	0	0	0	0	0	0	0
Special Purpose Charge Assessment Variance Account[4]	**1521**										
LRAM Variance Account	**1568**										
Total including Accounts 1562, 1521 and 1568		0	0	0	0	0	0	0	0	0	0

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year.

If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December 31, 2012 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded from January 1, 2012 to April 30, 2013 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision.

Applicants that did not have the balance in Account 1521 cleared by the Board in the 2012 rate proceedings are expected to file to dispose of Account 1521 in the 2013 rate proceedings. No Account 1521 balance is to be filed for clearance in the 2013 rate proceedings for those distributors that had account 1521 cleared by the Board in the 2012 rate proceedings.

In accordance with section 8 of the Special Purpose Charge ("SPC") Regulation, Ontario Regulation 66/10, distributors were required to apply to the Board no later than April 15, 2012 for an order authorizing the distributor to clear the balance in Account 1521. As per the Board's April 23, 2010 letter, the Board stated that it expected that requests for disposition of the balance in Account 1521 were to be addressed as part of the proceedings to set rates for the 2012 rate year, except in cases where this approach would result in non-compliance with the timeline set out in section 8 of the SPC Regulation.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund) period has been completed. If the recovery (or refund) period has not been completed, do not include the respective balance in Account 1595 for disposition at this time.

Please complete the following continuity schedule for the following Deferral / Variance Accounts. Enter information into green cells only.

If you have received approval to dispose of balances from prior years, the starting point for entries in the 2013 DVA schedule below will be the balance sheet date as per your G/L for which you received approval. For example, if in the 2012 EDR process (CoS or IRM) you received approval for the December 31, 2010 balances, the starting point for your entries below should be the adjustment column BF for principal and column BK for interest. This will allow for the correct starting point for the 2011 opening balance columns (for both principal and interest) without requiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

Please refer to the footnotes for further instructions.

		2009									
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-09	Transactions Debit / (Credit) during 2009 excluding interest and adjustments [2]	Board-Approved Disposition during 2009	Adjustments during 2009 - other [1]	Closing Principal Balance as of Dec-31-09	Opening Interest Amounts as of Jan-1-09	Interest Jan-1 to Dec-31-09	Board-Approved Disposition during 2009	Adjustments during 2009 - other [1]	Closing Interest Amounts as of Dec-31-09
Group 1 Accounts											
LV Variance Account	1550	0				0	0				0
RSVA - Wholesale Market Service Charge	1580	0				0	0				0
RSVA - Retail Transmission Network Charge	1584	0				0	0				0
RSVA - Retail Transmission Connection Charge	1586	0				0	0				0
RSVA - Power (excluding Global Adjustment)	1588	0				0	0				0
RSVA - Power - Sub-account - Global Adjustment	1588	0				0	0				0
Recovery of Regulatory Asset Balances	1590	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	1595	0				0	0				0
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		0	0	0	0	0	0	0	0	0	0
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		0	0	0	0	0	0	0	0	0	0
RSVA - Power - Sub-account - Global Adjustment	**1588**	0	0	0	0	0	0	0	0	0	0
Deferred Payments in Lieu of Taxes	1562	0				0	0				0
Total of Group 1 and Account 1562		0	0	0	0	0	0	0	0	0	0
Special Purpose Charge Assessment Variance Account[4]	**1521**										
LRAM Variance Account	**1568**										
Total including Accounts 1562, 1521 and 1568		0	0	0	0	0	0	0	0	0	0

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year.

If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December 31, 2012 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded from January 1, 2012 to April 30, 2013 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision.

Applicants that did not have the balance in Account 1521 cleared by the Board in the 2012 rate proceedings are expected to file to dispose of Account 1521 in the 2013 rate proceedings. No Account 1521 balance is to be filed for clearance in the 2013 rate proceedings for those distributors that had account 1521 cleared by the Board in the 2012 rate proceedings.

In accordance with section 8 of the Special Purpose Charge ("SPC") Regulation, Ontario Regulation 66/10, distributors were required to apply to the Board no later than April 15, 2012 for an order authorizing the distributor to clear the balance in Account 1521. As per the Board's April 23, 2010 letter, the Board stated that it expected that requests for disposition of the balance in Account 1521 were to be addressed as part of the proceedings to set rates for the 2012 rate year, except in cases where this approach would result in non-compliance with the timeline set out in section 8 of the SPC Regulation.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund) period has been completed. If the recovery (or refund) period has not been completed, do not include the respective balance in Account 1595 for disposition at this time.

Please complete the following continuity schedule for the following Deferral / Variance Accounts. Enter information into green cells only.

If you have received approval to dispose of balances from prior years, the starting point for entries in the 2013 DVA schedule below will be the balance sheet date as per your G/L for which you received approval. For example, if in the 2012 EDR process (CoS or IRM) you received approval for the December 31, 2010 balances, the starting point for your entries below should be the adjustment column BF for principal and column BK for interest. This will allow for the correct starting point for the 2011 opening balance columns (for both principal and interest) without requiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

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		2010									
Account Descriptions	**Account Number**	**Opening Principal Amounts as of Jan-1-10**	**Transactions Debit / (Credit) during 2010 excluding interest and adjustments [2]**	**Board-Approved Disposition during 2010**	**Adjustments during 2010 - other [1]**	**Closing Principal Balance as of Dec-31-10**	**Opening Interest Amounts as of Jan-1-10**	**Interest Jan-1 to Dec-31-10**	**Board-Approved Disposition during 2010**	**Adjustments during 2010 - other [2]**	**Closing Interest Amounts as of Dec-31-10**
Group 1 Accounts											
LV Variance Account	1550	0			(613,274)	(613,274)	0			(1,514)	(1,514)
RSVA - Wholesale Market Service Charge	1580	0			(503,791)	(503,791)	0			(120,129)	(120,129)
RSVA - Retail Transmission Network Charge	1584	0			601,339	601,339	0			(250,280)	(250,280)
RSVA - Retail Transmission Connection Charge	1586	0			517,827	517,827	0			(197,069)	(197,069)
RSVA - Power (excluding Global Adjustment)	1588	0			(473,530)	(473,530)	0			(431,019)	(431,019)
RSVA - Power - Sub-account - Global Adjustment	1588	0			2,249,396	2,249,396	0			10,170	10,170
Recovery of Regulatory Asset Balances	1590	0			(48,428)	(48,428)	0			117,050	117,050
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	1595	0			74,710	74,710	0			10,642	10,642
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	1595	0				0	0				0
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		0	0	0	1,804,249	1,804,249	0	0	0	(862,149)	(862,149)
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		0	0	0	(445,147)	(445,147)	0	0	0	(872,319)	(872,319)
RSVA - Power - Sub-account - Global Adjustment	**1588**	0	0	0	2,249,396	2,249,396	0	0	0	10,170	10,170
Deferred Payments in Lieu of Taxes	1562	0				0	0				0
Total of Group 1 and Account 1562		0	0	0	1,804,249	1,804,249	0	0	0	(862,149)	(862,149)
Special Purpose Charge Assessment Variance Account[4]	**1521**					0					0
LRAM Variance Account	**1568**					0					0
Total including Accounts 1562, 1521 and 1568		0	0	0	1,804,249	1,804,249	0	0	0	(862,149)	(862,149)

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year.

If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December 31, 2012 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded from January 1, 2012 to April 30, 2013 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision.

Applicants that did not have the balance in Account 1521 cleared by the Board in the 2012 rate proceedings are expected to file to dispose of Account 1521 in the 2013 rate proceedings. No Account 1521 balance is to be filed for clearance in the 2013 rate proceedings for those distributors that had account 1521 cleared by the Board in the 2012 rate proceedings.

In accordance with section 8 of the Special Purpose Charge ("SPC") Regulation, Ontario Regulation 66/10, distributors were required to apply to the Board no later than April 15, 2012 for an order authorizing the distributor to clear the balance in Account 1521. As per the Board's April 23, 2010 letter, the Board stated that it expected that requests for disposition of the balance in Account 1521 were to be addressed as part of the proceedings to set rates for the 2012 rate year, except in cases where this approach would result in non-compliance with the timeline set out in section 8 of the SPC Regulation.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund) period has been completed. If the recovery (or refund) period has not been completed, do not include the respective balance in Account 1595 for disposition at this time.

Please complete the following continuity schedule for the following Deferral / Variance Accounts. Enter information into green cells only.

If you have received approval to dispose of balances from prior years, the starting point for entries in the 2013 DVA schedule below will be the balance sheet date as per your G/L for which you received approval. For example, if in the 2012 EDR process (CoS or IRM) you received approval for the December 31, 2010 balances, the starting point for your entries below should be the adjustment column BF for principal and column BK for interest. This will allow for the correct starting point for the 2011 opening balance columns (for both principal and interest) without requiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

Please refer to the footnotes for further instructions.

		2011											
Account Descriptions	**Account Number**	**Opening Principal Amounts as of Jan-1-11**	**Transactions Debit / (Credit) during 2011 excluding interest and adjustments [2]**	**Board-Approved Disposition during 2011**	**Other [1] Adjustments during Q1 2011**	**Other [1] Adjustments during Q2 2011**	**Other [1] Adjustments during Q3 2011**	**Other [1] Adjustments during Q4 2011**	**Closing Principal Balance as of Dec-31-11**	**Opening Interest Amounts as of Jan-1-11**	**Interest Jan-1 to Dec-31-11**	**Board-Approved Disposition during 2011**	**Adjustments during 2011 - other [1]**
Group 1 Accounts													
LV Variance Account	1550	(613,274)	(24,512)						(637,786)	(1,514)	(10,680)		
RSVA - Wholesale Market Service Charge	1580	(503,791)	(471,889)						(975,680)	(120,129)	(11,099)		
RSVA - Retail Transmission Network Charge	1584	601,339	298,646						899,985	(250,280)	8,755		
RSVA - Retail Transmission Connection Charge	1586	517,827	122,290						640,117	(197,069)	7,261		
RSVA - Power (excluding Global Adjustment)	1588	(473,530)	(1,116,970)						(1,590,500)	(431,019)	(29,870)		
RSVA - Power - Sub-account - Global Adjustment	1588	2,249,396	1,090,312						3,339,708	10,170	48,794		
Recovery of Regulatory Asset Balances	1590	(48,428)	(211)						(48,639)	117,050	(712)		
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	1595	74,710	(47,723)						26,987	10,642	583		
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	1595	0							0	0			
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	1595	0							0	0			
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		1,804,249	(150,057)	0	0	0	0	0	1,654,192	(862,149)	13,032	0	0
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		(445,147)	(1,240,369)	0	0	0	0	0	(1,685,516)	(872,319)	(35,762)	0	0
RSVA - Power - Sub-account - Global Adjustment	**1588**	2,249,396	1,090,312	0	0	0	0	0	3,339,708	10,170	48,794	0	0
Deferred Payments in Lieu of Taxes	1562	0							0	0			
Total of Group 1 and Account 1562		1,804,249	(150,057)	0	0	0	0	0	1,654,192	(862,149)	13,032	0	0
Special Purpose Charge Assessment Variance Account[4]	**1521**	0							0	0			
LRAM Variance Account	**1568**	0							0	0			
Total including Accounts 1562, 1521 and 1568		1,804,249	(150,057)	0	0	0	0	0	1,654,192	(862,149)	13,032	0	0

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year.

If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December 31, 2012 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded from January 1, 2012 to April 30, 2013 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision.

Applicants that did not have the balance in Account 1521 cleared by the Board in the 2012 rate proceedings are expected to file to dispose of Account 1521 in the 2013 rate proceedings. No Account 1521 balance is to be filed for clearance in the 2013 rate proceedings for those distributors that had account 1521 cleared by the Board in the 2012 rate proceedings.

In accordance with section 8 of the Special Purpose Charge ("SPC") Regulation, Ontario Regulation 66/10, distributors were required to apply to the Board no later than April 15, 2012 for an order authorizing the distributor to clear the balance in Account 1521. As per the Board's April 23, 2010 letter, the Board stated that it expected that requests for disposition of the balance in Account 1521 were to be addressed as part of the proceedings to set rates for the 2012 rate year, except in cases where this approach would result in non-compliance with the timeline set out in section 8 of the SPC Regulation.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund) period has been completed. If the recovery (or refund) period has not been completed, do not include the respective balance in Account 1595 for disposition at this time.

Please complete the following continuity schedule for the following Deferral / Variance Accounts. Enter information into green cells only.

If you have received approval to dispose of balances from prior years, the starting point for entries in the 2013 DVA schedule below will be the balance sheet date as per your G/L for which you received approval. For example, if in the 2012 EDR process (CoS or IRM) you received approval for the December 31, 2010 balances, the starting point for your entries below should be the adjustment column BF for principal and column BK for interest. This will allow for the correct starting point for the 2011 opening balance columns (for both principal and interest) without requiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

Please refer to the footnotes for further instructions.

Account Descriptions	Account Number	Closing Interest Amounts as of Dec-31-11
Group 1 Accounts		
LV Variance Account	1550	(12,194)
RSVA - Wholesale Market Service Charge	1580	(131,228)
RSVA - Retail Transmission Network Charge	1584	(241,525)
RSVA - Retail Transmission Connection Charge	1586	(189,808)
RSVA - Power (excluding Global Adjustment)	1588	(460,889)
RSVA - Power - Sub-account - Global Adjustment	1588	58,964
Recovery of Regulatory Asset Balances	1590	116,338
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	1595	11,225
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	1595	0
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	1595	0
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		(849,117)
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		(908,081)
RSVA - Power - Sub-account - Global Adjustment	**1588**	58,964
Deferred Payments in Lieu of Taxes	1562	0
Total of Group 1 and Account 1562		(849,117)
Special Purpose Charge Assessment Variance Account[4]	**1521**	0
LRAM Variance Account	**1568**	0
Total including Accounts 1562, 1521 and 1568		(849,117)

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year.

If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December 31, 2012 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded from January 1, 2012 to April 30, 2013 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision.

Applicants that did not have the balance in Account 1521 cleared by the Board in the 2012 rate proceedings are expected to file to dispose of Account 1521 in the 2013 rate proceedings. No Account 1521 balance is to be filed for clearance in the 2013 rate proceedings for those distributors that had account 1521 cleared by the Board in the 2012 rate proceedings.

In accordance with section 8 of the Special Purpose Charge ("SPC") Regulation, Ontario Regulation 66/10, distributors were required to apply to the Board no later than April 15, 2012 for an order authorizing the distributor to clear the balance in Account 1521. As per the Board's April 23, 2010 letter, the Board stated that it expected that requests for disposition of the balance in Account 1521 were to be addressed as part of the proceedings to set rates for the 2012 rate year, except in cases where this approach would result in non-compliance with the timeline set out in section 8 of the SPC Regulation.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund) period has been completed. If the recovery (or refund) period has not been completed, do not include the respective balance in Account 1595 for disposition at this time.

Please complete the following continuity schedule for the following Deferral / Variance Accounts. Enter information into green cells only.

If you have received approval to dispose of balances from prior years, the starting point for entries in the 2013 DVA schedule below will be the balance sheet date as per your G/L for which you received approval. For example, if in the 2012 EDR process (CoS or IRM) you received approval for the December 31, 2010 balances, the starting point for your entries below should be the adjustment column BF for principal and column BK for interest. This will allow for the correct starting point for the 2011 opening balance columns (for both principal and interest) without requiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

Please refer to the footnotes for further instructions.

		2012				Projected Interest on Dec-31-11 Balances			2.1.7 RRR	
Account Descriptions	**Account Number**	**Principal Disposition during 2012 - instructed by Board**	**Interest Disposition during 2012 - instructed by Board**	**Closing Principal Balances as of Dec 31-11 Adjusted for Dispositions during 2012**	**Closing Interest Balances as of Dec 31-11 Adjusted for Dispositions during 2012**	**Projected Interest from Jan 1, 2012 to December 31, 2012 on Dec 31 -11 balance adjusted for disposition during 2012 [3]**	**Projected Interest from January 1, 2013 to April 30, 2013 on Dec 31 -11 balance adjusted for disposition during 2012 [3]**	**Total Claim**	**As of Dec 31-11**	**Variance RRR vs. 2011 Balance *(Principal + Interest)***
Group 1 Accounts										
LV Variance Account	1550	(613,274)	(13,534)	(24,512)	1,340	(360)	(120)	(23,652)	(649,980)	0
RSVA - Wholesale Market Service Charge	1580	(503,791)	(130,003)	(471,889)	(1,225)	(6,937)	(2,312)	(482,363)	(1,106,908)	0
RSVA - Retail Transmission Network Charge	1584	601,339	(238,494)	298,646	(3,031)	4,390	1,463	301,468	658,460	(0)
RSVA - Retail Transmission Connection Charge	1586	517,827	(186,920)	122,290	(2,888)	1,798	599	121,799	450,310	1
RSVA - Power (excluding Global Adjustment)	1588	(473,530)	(440,300)	(1,116,970)	(20,589)	(16,419)	(5,473)	(1,159,452)	(2,051,389)	0
RSVA - Power - Sub-account - Global Adjustment	1588	2,249,396	54,258	1,090,312	4,706	16,028	5,343	1,116,388	3,398,672	(0)
Recovery of Regulatory Asset Balances	1590	(48,428)	116,101	(211)	237	(3)	(1)	22	67,699	0
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	1595			26,987	11,225	397	132	38,741	38,212	(0)
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	1595			0	0	0	0	0		0
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	1595			0	0	0	0	0		0
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		1,729,539	(838,892)	(75,347)	(10,225)	(1,108)	(369)	(87,049)	805,076	1
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		(519,857)	(893,150)	(1,165,659)	(14,931)	(17,135)	(5,712)	(1,203,437)	(2,593,596)	1
RSVA - Power - Sub-account - Global Adjustment	**1588**	2,249,396	54,258	1,090,312	4,706	16,028	5,343	1,116,388	3,398,672	(0)
Deferred Payments in Lieu of Taxes	1562			0	0	0	0	0		0
										0
Total of Group 1 and Account 1562		1,729,539	(838,892)	(75,347)	(10,225)	(1,108)	(369)	(87,049)	805,076	1
Special Purpose Charge Assessment Variance Account[4]	**1521**			0	0	0	0	0		0
LRAM Variance Account	**1568**			0	0	0	0	0		0
Total including Accounts 1562, 1521 and 1568		1,729,539	(838,892)	(75,347)	(10,225)	(1,108)	(369)	(87,049)	805,076	1

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year.

If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December 31, 2012 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded from January 1, 2012 to April 30, 2013 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision.

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In accordance with section 8 of the Special Purpose Charge ("SPC") Regulation, Ontario Regulation 66/10, distributors were required to apply to the Board no later than April 15, 2012 for an order authorizing the distributor to clear the balance in Account 1521. As per the Board's April 23, 2010 letter, the Board stated that it expected that requests for disposition of the balance in Account 1521 were to be addressed as part of the proceedings to set rates for the 2012 rate year, except in cases where this approach would result in non-compliance with the timeline set out in section 8 of the SPC Regulation.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund) period has been completed. If the recovery (or refund) period has not been completed, do not include the respective balance in Account 1595 for disposition at this time.

In the green shaded cells, enter the most recent Board Approved volumetric forecast. If there is a material difference between the latest Board-approved volumetric forecast and the most recent 12-month actual volumetric data, use the most recent 12-month actual data. Do not enter data for the MicroFit class.

Rate Class	Unit	Metered kWh	Metered kW	Billed kWh for Non-RPP Customers	Estimated kW for Non-RPP Customers	Distribution Revenue [1]	1590 Recovery Share Proportion*	1595 Recovery Share Proportion (2008) [2]	1595 Recovery Share Proportion (2009) [2]	1595 Recovery Share Proportion (2010) [2]	1568 LRAM Variance Account Class Allocation ($ amounts)
Residential - Time of Use	$/kWh	210,909,970		22,274,302	0	5,280,540					
General Service Less Than 50 kW	$/kWh	51,848,139		4,601,906	0	991,335					
General Service 50 to 999 kW	$/kW	116,644,470	326,358	97,898,038	273,908	1,193,153					
General Service 1,000 to 4,999 kW - Interval Meters	$/kW	103,667,742	281,618	103,667,742	281,618	772,817					
Unmetered Scattered Load	$/kWh	946,987		946,987	0	17,268					
Sentinel Lighting	$/kW	695,540	1,480	695,540	1,480	25,175					
Street Lighting	$/kW	2,817,289	7,928	2,817,289	7,928	341,198					
MicroFit											
	Total	**487,530,137**	**617,384**	**232,901,804**	**564,934**	**8,621,486**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0**
										Balance as per Sheet 5	0
										Variance	0

Threshold Test

Total Claim (including Account 1521, 1562 and 1568)	($87,049)	
Total Claim for Threshold Test (All Group 1 Accounts)	($87,049)	
Threshold Test (Total claim per kWh) [3]	(0.0002)	**Claim does not meet the threshold test. If data has been entered on Sheet 5 for Accounts 1521 and 1562, the model will only dispose of Accounts 1521 and 1562.**

[1] For Account 1562, the allocation to customer classes should be performed on the basis of the test year distribution revenue allocation to customer classes found in the Applicant's Cost of Service application that was most recently approved at the time of disposition of the 1562 account balances
[2] Residual Account balance to be allocated to rate classes in proportion to the recovery share as established when rate riders were implemented.
[3] The Threshold Test does not include the amount in 1521, 1562 nor 1568.

3RD Generation Incentive Regulation Model for 2013 Filers

Halton Hills Hydro Inc.

No input required. This workshseet allocates the deferral/variance account balances (Group 1, 1521, 1588 GA, 1562 and 1568) to the appropriate classes as per the EDDVAR Report dated July 31, 2009

Allocation of Group 1 Accounts (including Accounts 1521, 1562, 1568)

Rate Class	% of Total kWh	% of Total non-RPP kWh	% of Total Distribution Revenue	1550	1580	1584	1586	1588*	1588 GA	1590	1595 (2008)	1595 (2009)	1595 (2010)	1521	1562	1568
Residential - Time of Use	43.3%	9.6%	61.2%	0	0	0	0	0	0	0	0	0	0	0	0	0
General Service Less Than 50 kW	10.6%	2.0%	11.5%	0	0	0	0	0	0	0	0	0	0	0	0	0
General Service 50 to 999 kW	23.9%	42.0%	13.8%	0	0	0	0	0	0	0	0	0	0	0	0	0
General Service 1,000 to 4,999 kW - Interval Meters	21.3%	44.5%	9.0%	0	0	0	0	0	0	0	0	0	0	0	0	0
Unmetered Scattered Load	0.2%	0.4%	0.2%	0	0	0	0	0	0	0	0	0	0	0	0	0
Sentinel Lighting	0.1%	0.3%	0.3%	0	0	0	0	0	0	0	0	0	0	0	0	0
Street Lighting	0.6%	1.2%	4.0%	0	0	0	0	0	0	0	0	0	0	0	0	0
MicroFit	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	**100.0%**	**100.0%**	**100.0%**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

** RSVA - Power (Excluding Global Adjustment)*

3RD Generation Incentive Regulation Model for 2013 Filers

Halton Hills Hydro Inc.

Input required at cell C15 only. This workshseet calculates rate riders related to the Deferral/Variance Account Disposition (if applicable) and associated rate riders for the global adjustment sub-account. Rate Riders will not be generated for the MicroFit class.

Please indicate the Rate Rider Recovery Period (in years) 1

Rate Class	Unit	Billed kWh	Billed kW	Balance of Accounts Allocated by kWh/kW (RPP) or Distribution	Deferral/Variance Account Rate Rider	Allocation of Balance in Account 1588 Global	Billed kWh or Estimated kW for Non-RPP	Global Adjustment Rate Rider
Residential - Time of Use	$/kWh	210,909,970		0	0.0000	0	22,274,302	0.0000
General Service Less Than 50 kW	$/kWh	51,848,139		0	0.0000	0	4,601,906	0.0000
General Service 50 to 999 kW	$/kW	116,644,470	326,358	0	0.0000	0	273,908	0.0000
General Service 1,000 to 4,999 kW - Interval Meters	$/kW	103,667,742	281,618	0	0.0000	0	281,618	0.0000
Unmetered Scattered Load	$/kWh	946,987		0	0.0000	0	946,987	0.0000
Sentinel Lighting	$/kW	695,540	1,480	0	0.0000	0	1,480	0.0000
Street Lighting	$/kW	2,817,289	7,928	0	0.0000	0	7,928	0.0000
MicroFit								
Total		**487,530,137**	**617,384**	**0**		**0**	**28,388,129**	

3RD Generation Incentive Regulation Model for 2013 Filers

Halton Hills Hydro Inc.

If applicable, please enter any adjustments related to the revenue to cost ratio model into columns C and E.
The Price Escalator has been set at the 2012 values and will be updated by Board staff. The Stretch Factor Value will also be updated by Board staff.

Price Escalator	**2.00%**	**Choose Stretch Factor Group**	II
Productivity Factor	**0.72%**	**Associated Stretch Factor Value**	**0.4%**
Price Cap Index	**0.88%**		

Rate Class	**Current MFC**	**MFC Adjustment from R/C Model**	**Current Volumetric Charge**	**DVR Adjustment from R/C Model**	**Price Cap Index to be Applied to MFC and DVR**	**Proposed MFC**	**Proposed Volumetric Charge**
Residential - Time of Use	12.25		0.0115		0.88%	12.36	0.0116
General Service Less Than 50 kW	26.50		0.0083		0.88%	26.73	0.0084
General Service 50 to 999 kW	74.64		3.3287		0.88%	75.30	3.3580
General Service 1,000 to 4,999 kW - Interval Meters	173.31		3.0517		0.88%	174.84	3.0786
Unmetered Scattered Load	6.50		0.0043		0.88%	6.56	0.0043
Sentinel Lighting	4.88		18.4557		0.88%	4.92	18.6181
Street Lighting	2.14		28.9538		0.88%	2.16	29.2086
MicroFit	5.40					5.40	

Please enter the following charges as found on your most recent Board-Approved Tariff Schedule. The standard Allowance rates have been included as default entries. If you have different rates, please make the appropriate corrections in the applicable cells below. As well, please enter the current Specific Service Charges below. The standard Retail Service Charges have been entered below. If you have different rates, please make the appropriate corrections in columns A, C or D as applicable (cells are unlocked).

ALLOWANCES

	UNIT	CURRENT
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.50)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration

Arrears certificate	$	15.00
Statement of Account	$	15.00
Pulling Post Dated Cheques	$	15.00
Duplicate Invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income Tax Letter	$	15.00
Notification charge	$	15.00
Account History	$	15.00
Credit Reference/credit check (plus credit agency costs)	$	15.00
Returned cheque (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Credit reference Letter		

Non-Payment of Account

Late Payment – per month	%	1.50
Late Payment – per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge – no disconnection – after regular hours	$	165.00
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect at meter – after regular hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Service call – customer owned equipment	$	30.00
Service call – after regular hours	$	165.00
Temporary service install & remove – overhead – no transformer	$	500.00
Temporary service installation and removal – underground – no transformer	$	300.00
Temporary Service – Install & remove – overhead – with transformer	$	1,000.00
Specific Charge for Access to the Power Poles - $/pole/year	$	22.35
Interval Meter Charge	$	20.00

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0602
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0496
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

3RD Generation Incentive Regulation Model for 2013 Filers

Halton Hills Hydro Inc.

Below is a listing of the proposed Monthly Fixed Charges, proposed Distribution Volumetric Rates, proposed Deferral and Variance account Rate Riders and all unexpired volumetric rates that were entered on Sheet 4. In the green cells (column A) below, please enter any additional rates being proposed (eg: LRAM/SSM, Tax Adjustments, etc). Please ensure that the word "Rider" or "Adder" is included in the description (as applicable). Note: All rates with expired effective dates have been removed. As well, the Current RTSR-Network and RTSR-Connection rate descriptions entered on Sheet 4 can be found below. The associated rates have been removed from this sheet, giving the applicant the opportunity to enter updated rates (from Sheet 13 in the Board-Approved RTSR model into the cells in column I.

RESIDENTIAL - TIME OF USE SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	12.36
Distribution Volumetric Rate	$/kWh	0.0116
Low Voltage Service Rate	$/kWh	0.0012
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	0.0012
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kWh	(0.0018)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery (2012) – Effective until April 30, 2014	$/kWh	0.0007
Retail Transmission Rate - Network Service Rate	$/kWh	**0.0057**
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	**0.0046**
Rate Rider for Recovery of Residual Historical Smart Meter Costs - effective July 1, 2012 - April 30, 2016	$	1.31
Rate Rider for Recovery of Stranded Meter Assets - effective July 1, 2012 - April 30, 2016	$	1.13

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	26.73
Distribution Volumetric Rate	$/kWh	0.0084
Low Voltage Service Rate	$/kWh	0.0011
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kWh	(0.0018)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery (2012) – Effective until April 30, 2014	$/kWh	0.0007
Retail Transmission Rate - Network Service Rate	$/kWh	**0.0051**
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	**0.0043**
Rate Rider for Recovery of Residual Historical Smart Meter Costs - effective July 1, 2012 - April 30, 2016	$	1.38
Rate Rider for Recovery of Stranded Meter Assets - effective July 1, 2012 - April 30, 2016	$	1.46

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	75.30
Distribution Volumetric Rate	$/kW	3.3580
Low Voltage Service Rate	$/kW	0.4734
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	1.5817
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kW	(0.7063)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery (2012) – Effective until April 30, 2014	$/kW	0.0490
Retail Transmission Rate - Network Service Rate	$/kW	**2.2261**
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	**1.8336**

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE 1,000 TO 4,999 KW - INTERVAL METERS SERVICE CLASSIFICAT

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	174.84
Distribution Volumetric Rate	$/kW	3.0786
Low Voltage Service Rate	$/kW	0.4734
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	1.9530
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kW	(0.7409)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery (2012) – Effective until April 30, 2014	$/kW	0.0108
Retail Transmission Rate - Network Service Rate	$/kW	**2.2261**
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	**1.8336**

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	6.56
Distribution Volumetric Rate	$/kWh	0.0043
Low Voltage Service Rate	$/kWh	0.0011
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kWh	0.0053
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kWh	(0.0016)
Retail Transmission Rate - Network Service Rate	$/kWh	**0.0051**
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	**0.0043**

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

SENTINEL LIGHTING SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	4.92
Distribution Volumetric Rate	$/kW	18.6181
Low Voltage Service Rate	$/kW	0.3408
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	18.2482
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kW	(0.7438)
Retail Transmission Rate - Network Service Rate	$/kW	**1.5881**
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	**1.3201**

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

STREET LIGHTING SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	2.16
Distribution Volumetric Rate	$/kW	29.2086
Low Voltage Service Rate	$/kW	0.3338
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	0.2586
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kW	(0.0754)
Retail Transmission Rate - Network Service Rate	$/kW	**1.5808**
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	**1.2931**

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

MICROFIT SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

3RD Generation Incentive Regulation Model for 2013 Filers

Halton Hills Hydro Inc.

The following table provides applicants with a class to class comparison of current vs. proposed rates.

Current Rates

Rate Description	Unit	Amount
Residential - Time of Use		
Service Charge	$	12.25
Distribution Volumetric Rate	$/kWh	0.0115
Low Voltage Service Rate	$/kWh	0.0012
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	0.0012
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kWh	(0.0018)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery (2012) – Effective until April 30, 2014	$/kWh	0.0007
Retail Transmission Rate - Network Service Rate	$/kWh	0.0057
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0045
Rate Rider for Recovery of Foregone Revenue - effective July 1, 2012 - April 30, 2013	$	(0.14)
Rate Rider for Recovery of Foregone Revenue - effective July 1, 2012 - April 30, 2013	$/kWh	(0.0001)
Rate Rider for Recovery of Residual Historical Smart Meter Costs - effective July 1, 2012 - April 30, 2016	$	1.31
Rate Rider for Recovery of Stranded Meter Assets - effective July 1, 2012 - April 30, 2016	$	1.13
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge - effective until April 30, 2012	$/kWh	0.0013
Rural Rate Protection Charge - effective on and after May 1, 2012	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25
General Service Less Than 50 kW		
Service Charge	$	26.50
Distribution Volumetric Rate	$/kWh	0.0083
Low Voltage Service Rate	$/kWh	0.0011
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kWh	(0.0018)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery (2012) – Effective until April 30, 2014	$/kWh	0.0007
Retail Transmission Rate - Network Service Rate	$/kWh	0.0051
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0042
Rate Rider for Recovery of Foregone Revenue - effective July 1, 2012 - April 30, 2013	$	(0.36)
Rate Rider for Recovery of Foregone Revenue - effective July 1, 2012 - April 30, 2013	$/kWh	(0.0001)
Rate Rider for Recovery of Residual Historical Smart Meter Costs - effective July 1, 2012 - April 30, 2016	$	1.38
Rate Rider for Recovery of Stranded Meter Assets - effective July 1, 2012 - April 30, 2016	$	1.46
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge - effective until April 30, 2012	$/kWh	0.0013
Rural Rate Protection Charge - effective on and after May 1, 2012	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25
General Service 50 to 999 kW		
Service Charge	$	74.64
Distribution Volumetric Rate	$/kW	3.3287
Low Voltage Service Rate	$/kW	0.4734

Proposed Rates

Rate Description	Unit	Amount
Residential - Time of Use		
Service Charge	$	12.36
Distribution Volumetric Rate	$/kWh	0.0116
Low Voltage Service Rate	$/kWh	0.0012
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	0.0012
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kWh	(0.0018)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery (2012) – Effective until April 30, 2014	$/kWh	0.0007
Retail Transmission Rate - Network Service Rate	$/kWh	0.0057
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0046
Rate Rider for Recovery of Residual Historical Smart Meter Costs - effective July 1, 2012 - April 30, 2016	$	1.31
Rate Rider for Recovery of Stranded Meter Assets - effective July 1, 2012 - April 30, 2016	$	1.13
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25
General Service Less Than 50 kW		
Service Charge	$	26.73
Distribution Volumetric Rate	$/kWh	0.0084
Low Voltage Service Rate	$/kWh	0.0011
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kWh	(0.0018)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery (2012) – Effective until April 30, 2014	$/kWh	0.0007
Retail Transmission Rate - Network Service Rate	$/kWh	0.0051
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0043
Rate Rider for Recovery of Residual Historical Smart Meter Costs - effective July 1, 2012 - April 30, 2016	$	1.38
Rate Rider for Recovery of Stranded Meter Assets - effective July 1, 2012 - April 30, 2016	$	1.46
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25
General Service 50 to 999 kW		
Service Charge	$	75.30
Distribution Volumetric Rate	$/kW	3.3580
Low Voltage Service Rate	$/kW	0.4734

Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	1.5817
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kW	(0.7063)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery (2012) – Effective until April 30, 2014	$/kW	0.0490
Retail Transmission Rate - Network Service Rate	$/kW	2.2257
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7975
Rate Rider for Recovery of Foregone Revenue - effective July 1, 2012 - April 30, 2013	$	(0.31)
Rate Rider for Recovery of Foregone Revenue - effective July 1, 2012 - April 30, 2013	$/kW	(0.0130)
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge - effective until April 30, 2012	$/kWh	0.0013
Rural Rate Protection Charge - effective on and after May 1, 2012	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

General Service 1,000 to 4,999 kW - Interval Meters

Service Charge	$	173.31
Distribution Volumetric Rate	$/kW	3.0517
Low Voltage Service Rate	$/kW	0.4734
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	1.9530
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kW	(0.7409)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery (2012) – Effective until April 30, 2014	$/kW	0.0108
Retail Transmission Rate - Network Service Rate	$/kW	2.2257
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7975
Rate Rider for Recovery of Foregone Revenue - effective July 1, 2012 - April 30, 2013	$/kW	(0.1108)
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge - effective until April 30, 2012	$/kWh	0.0013
Rural Rate Protection Charge - effective on and after May 1, 2012	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge	$	6.50
Distribution Volumetric Rate	$/kWh	0.0043
Low Voltage Service Rate	$/kWh	0.0011
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	0.0053
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kWh	(0.0016)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0051
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0042
Rate Rider for Recovery of Foregone Revenue - effective July 1, 2012 - April 30, 2013	$	(1.24)
Rate Rider for Recovery of Foregone Revenue - effective July 1, 2012 - April 30, 2013	$/kWh	(0.0008)
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge - effective until April 30, 2012	$/kWh	0.0013
Rural Rate Protection Charge - effective on and after May 1, 2012	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	$	4.88
Distribution Volumetric Rate	$/kW	18.4557
Low Voltage Service Rate	$/kW	0.3408
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	18.2482
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kW	(0.7438)
Retail Transmission Rate - Network Service Rate	$/kW	1.5878
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.2941
Rate Rider for Recovery of Foregone Revenue - effective July 1, 2012 - April 30, 2013	$	0.44
Rate Rider for Recovery of Foregone Revenue - effective July 1, 2012 - April 30, 2013	$/kW	1.6698
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge - effective until April 30, 2012	$/kWh	0.0013

Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	1.5817
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kW	(0.7063)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery (2012) – Effective until April 30, 2014	$/kW	0.0490
Retail Transmission Rate - Network Service Rate	$/kW	2.2261
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8336
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

General Service 1,000 to 4,999 kW - Interval Meters

Service Charge	$	174.84
Distribution Volumetric Rate	$/kW	3.0786
Low Voltage Service Rate	$/kW	0.4734
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	1.9530
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kW	(0.7409)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery (2012) – Effective until April 30, 2014	$/kW	0.0108
Retail Transmission Rate - Network Service Rate	$/kW	2.2261
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8336
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge	$	6.56
Distribution Volumetric Rate	$/kWh	0.0043
Low Voltage Service Rate	$/kWh	0.0011
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	0.0053
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kWh	(0.0016)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0051
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0043
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	$	4.92
Distribution Volumetric Rate	$/kW	18.6181
Low Voltage Service Rate	$/kW	0.3408
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	18.2482
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kW	(0.7438)
Retail Transmission Rate - Network Service Rate	$/kW	1.5881
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.3201
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Rural Rate Protection Charge - effective on and after May 1, 2012	$/kWh	0.0011			
Standard Supply Service - Administrative Charge (if applicable)	$	0.25			
Street Lighting			**Street Lighting**		
Service Charge (per connection)	$	2.14	Service Charge (per connection)	$	2.16
Distribution Volumetric Rate	$/kW	28.9538	Distribution Volumetric Rate	$/kW	29.2086
Low Voltage Service Rate	$/kW	0.3338	Low Voltage Service Rate	$/kW	0.3338
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	0.2586	Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	0.2586
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kW	(0.0754)	Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kW	(0.0754)
Retail Transmission Rate - Network Service Rate	$/kW	1.5805	Retail Transmission Rate - Network Service Rate	$/kW	1.5808
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.2676	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.2931
Rate Rider for Recovery of Foregone Revenue - effective July 1, 2012 - April 30, 2013	$	(0.03)	Wholesale Market Service Rate	$/kWh	0.0052
Rate Rider for Recovery of Foregone Revenue - effective July 1, 2012 - April 30, 2013	$/kW	(0.4379)	Rural Rate Protection Charge	$/kWh	0.0011
Wholesale Market Service Rate	$/kWh	0.0052	Standard Supply Service - Administrative Charge (if applicable)	$	0.25
Rural Rate Protection Charge - effective until April 30, 2012	$/kWh	0.0013			
Rural Rate Protection Charge - effective on and after May 1, 2012	$/kWh	0.0011			
Standard Supply Service - Administrative Charge (if applicable)	$	0.25			
MicroFit			**MicroFit**		
Service Charge	$	5.40	Service Charge	$	5.40

The following is a complete Tariff Schedule based on the information entered in this model. Please review.
Note: This worksheet is **unlocked** and the print margins, row heights, number formats, etc. can be adjusted.

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 01, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0130

RESIDENTIAL - TIME OF USE SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning.
Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. The customer will be supplied at one service

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	12.36
Distribution Volumetric Rate	$/kWh	0.0116
Low Voltage Service Rate	$/kWh	0.0012
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kWh	0.0012
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kWh	(0.0018)
Effective until April 30, 2014	$/kWh	0.0007
Retail Transmission Rate - Network Service Rate	$/kWh	0.0057
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0046
Rate Rider for Recovery of Residual Historical Smart Meter Costs - effective July 1, 2012 - April 30, 2016	$	1.31
Rate Rider for Recovery of Stranded Meter Assets - effective July 1, 2012 - April 30, 2016	$	1.13

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	26.73
Distribution Volumetric Rate	$/kWh	0.0084
Low Voltage Service Rate	$/kWh	0.0011
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kWh	(0.0018)
Effective until April 30, 2014	$/kWh	0.0007
Retail Transmission Rate - Network Service Rate	$/kWh	0.0051
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0043
Rate Rider for Recovery of Residual Historical Smart Meter Costs - effective July 1, 2012 - April 30, 2016	$	1.38
Rate Rider for Recovery of Stranded Meter Assets - effective July 1, 2012 - April 30, 2016	$	1.46

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION

This classification applies to a non-residential customer with an average peak demand equal to or greater than 50 kW over the past twelve months, or is forecast to be equal to or greater than 50 kW, but less than 1,000 kW. For a new customer without prior billing history, the peak demand will be based on 90% of the proposed capacity or installed

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	75.30
Distribution Volumetric Rate	$/kW	3.3580
Low Voltage Service Rate	$/kW	0.4734
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	1.5817
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kW	(0.7063)
Effective until April 30, 2014	$/kW	0.0490
Retail Transmission Rate - Network Service Rate	$/kW	2.2261
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8336

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE 1,000 TO 4,999 KW - INTERVAL METERS SERVICE CLASSIFICATIO

This classification applies to a non-residential customer with an average peak demand equal to or greater than 1,000 kW over the past twelve months, or is forecast to be equal to or greater than 1,000 kW, but less than 5,000 kW. For a new customer without prior billing history, the peak demand will be based on 90% of the installed transformer.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	174.84
Distribution Volumetric Rate	$/kW	3.0786
Low Voltage Service Rate	$/kW	0.4734
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	1.9530
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kW	(0.7409)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery (2012) – Effective until April 30, 2014	$/kW	0.0108
Retail Transmission Rate - Network Service Rate	$/kW	2.2261
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8336

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, pedestrian X-Walk signals/beacons, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	6.56
Distribution Volumetric Rate	$/kWh	0.0043
Low Voltage Service Rate	$/kWh	0.0011
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kWh	0.0053
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kWh	(0.0016)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0051
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0043

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	4.92
Distribution Volumetric Rate	$/kW	18.6181
Low Voltage Service Rate	$/kW	0.3408
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	18.2482
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kW	(0.7438)
Retail Transmission Rate - Network Service Rate	$/kW	1.5881
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.3201

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

STREET LIGHTING SERVICE CLASSIFICATION

All services supplied to street lighting equipment owned by or operated for the Municipality, the Region or the Province of Ontario shall be classified as Street Lighting Service. Street Lighting plant, facilities, or equipment owned by the customer are subject to the Electrical Safety Authority (ESA) requirements and Halton Hills Hydro

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	2.16
Distribution Volumetric Rate	$/kW	29.2086
Low Voltage Service Rate	$/kW	0.3338
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	0.2586
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kW	(0.0754)
Retail Transmission Rate - Network Service Rate	$/kW	1.5808
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.2931

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

MICROFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.50)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration

Arrears certificate	$	15.00
Statement of Account	$	15.00
Pulling Post Dated Cheques	$	15.00
Duplicate Invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income Tax Letter	$	15.00
Notification charge	$	15.00
Account History	$	15.00
Credit Reference/credit check (plus credit agency costs)	$	15.00
Returned cheque (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Credit reference Letter		

Non-Payment of Account

Late Payment – per month	%	1.50
Late Payment – per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge – no disconnection – after regular hours	$	165.00
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect at meter – after regular hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Service call – customer owned equipment	$	30.00
Service call – after regular hours	$	165.00
Temporary service install & remove – overhead – no transformer	$	500.00
Temporary service installation and removal – underground – no transformer	$	300.00
Temporary Service – Install & remove – overhead – with transformer	$	1,000.00
Specific Charge for Access to the Power Poles - $/pole/year	$	22.35
Interval Meter Charge	$	20.00

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0602
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0496
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

Choose a Rate Class from the drop-down menu below and click UPDATE.

For Street Lighting and USL classes, please ensure that the number of customers is manually entered into cells *B30* and *B31*.

Click the UPDATE button to refresh the sheet.

Residential - Time of Use

Consumption	800	**kWh**
RPP Tier One	600	**kWh**
Load Factor		
Loss Factor	1.0602	

	CURRENT ESTIMATED BILL			PROPOSED ESTIMATED BILL						
	Volume	**Current Rate ($)**	**Current Charge ($)**	**Volume**	**Proposed Rate ($)**	**Proposed Charge ($)**	**Change ($)**	**Change (%)**	**% of Total RPP Bill**	**% of Total TOU Bill**
Energy First Tier (kWh)	600.00	0.0750	45.00	600.00	0.0750	45.00	0.00	0.00%	39.89%	
Energy Second Tier (kWh)	248.16	0.0880	21.84	248.16	0.0880	21.84	0.00	0.00%	19.36%	
TOU - Off Peak	542.82	0.0650	35.28	542.82	0.0650	35.28	0.00	0.00%		30.84%
TOU - Mid Peak	152.67	0.1000	15.27	152.67	0.1000	15.27	0.00	0.00%		13.34%
TOU - On Peak	152.67	0.1170	17.86	152.67	0.1170	17.86	0.00	0.00%		15.61%
Service Charge	1	12.25	12.25	1	12.36	12.36	0.11	0.90%	10.96%	10.80%
Service Charge Rate Rider(s)	1	2.30	2.30	1	2.44	2.44	0.14	6.09%	2.16%	2.13%
Distribution Volumetric Rate	800	0.0115	9.20	800	0.0116	9.28	0.08	0.87%	8.23%	8.11%
Low Voltage Volumetric Rate	800	0.0012	0.96	800	0.0012	0.96	0.00	0.00%	0.85%	0.84%
Distribution Volumetric Rate Rider(s)	800	(0.0012)	(0.96)	800	(0.0011)	(0.88)	0.08	(8.33)%	-0.78%	-0.77%
Total: Distribution			**23.75**			**24.16**	**0.41**	**1.73%**	**21.42%**	**21.12%**

Appendix B

2013 RTSR MODEL_V3_20120628

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v 3.0

RTSR Workform for Electricity Distributors (2013 Filers)

Utility Name	Halton Hills Hydro Inc.
Assigned EB Number	EB-2012-0130
Name and Title	David Smelsky, Chief Financial Officer
Phone Number	519-853-3700 ext 208
Email Address	dsmelsky@haltonhillshydro.com
Date	12-Oct-12
Last COS Re-based Year	**2012**

Note: Drop-down lists are shaded blue; Input cells are shaded green.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

RTSR Workform for Electricity Distributors (2013 Filers)

RTSR Workform for Electricity Distributors (2013 Filers)

1. Select the appropriate rate classes that appear on your most recent Board-Approved Tariff of Rates and Charges.
2. Enter the RTS Network and Connection Rate as it appears on the Tariff of Rates and Charges

Rate Class	Unit	RTSR-Network	RTSR-Connection
Residential - Time of Use	kWh	$ 0.0057	$ 0.0045
General Service Less Than 50 kW	kWh	$ 0.0051	$ 0.0042
General Service 50 to 999 kW	kW	$ 2.2257	$ 1.7975
General Service 1,000 to 4,999 kW - Interval Meters	kW	$ 2.2257	$ 1.7975
Unmetered Scattered Load	kWh	$ 0.0051	$ 0.0042
Sentinel Lighting	kW	$ 1.5878	$ 1.2941
Street Lighting	kW	$ 1.5805	$ 1.2676
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			

RTSR Workform for Electricity Distributors (2013 Filers)

In the green shaded cells, enter the most recent reported RRR billing determinants. Please ensure that billing determinants are non-loss adjusted.

Rate Class	Unit	Non-Loss Adjusted Metered kWh	Non-Loss Adjusted Metered kW	Applicable Loss Factor	Load Factor	Loss Adjusted Billed kWh	Billed kW
Residential - Time of Use	kWh	213,773,795	-	1.0602		226,642,977	-
General Service Less Than 50 kW	kWh	57,401,529	-	1.0602		60,857,101	-
General Service 50 to 999 kW	kW	115,214,051	318,520		49.58%	115,214,051	318,520
General Service 1,000 to 4,999 kW - Interval Meters	kW	105,252,631	294,618		48.97%	105,252,631	294,618
Unmetered Scattered Load	kWh	891,675	-	1.0602		945,354	-
Sentinel Lighting	kW	503,097	520		132.61%	503,097	520
Street Lighting	kW	2,743,202	7,634		49.25%	2,743,202	7,634

RTSR Workform for Electricity Distributors (2013 Filers)

Uniform Transmission Rates	Unit	Effective January 1, 2011	Effective January 1, 2012	Effective January 1, 2013
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 3.22	$ 3.57	$ 3.57
Line Connection Service Rate	kW	$ 0.79	$ 0.80	$ 0.80
Transformation Connection Service Rate	kW	$ 1.77	$ 1.86	$ 1.86

Hydro One Sub-Transmission Rates	Unit	Effective January 1, 2011	Effective January 1, 2012	Effective January 1, 2013
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 2.65	$ 2.65	$ 2.65
Line Connection Service Rate	kW	$ 0.64	$ 0.64	$ 0.64
Transformation Connection Service Rate	kW	$ 1.50	$ 1.50	$ 1.50
Both Line and Transformation Connection Service Rate	kW	$ 2.14	$ 2.14	$ 2.14

Hydro One Sub-Transmission Rate Rider 6A	Unit	Effective January 1, 2011	Effective January 1, 2012	Effective January 1, 2013
Rate Description		**Rate**	**Rate**	**Rate**
RSVA Transmission network – 4714 – which affects 1584	kW	$ 0.0470	$ -	$ -
RSVA Transmission connection – 4716 – which affects 1586	kW	-$ 0.0250	$ -	$ -
RSVA LV – 4750 – which affects 1550	kW	$ 0.0580	$ -	$ -
RARA 1 – 2252 – which affects 1590	kW	-$ 0.0750	$ -	$ -
Hydro One Sub-Transmission Rate Rider 6A	kW	$ 0.0050	$ -	$ -

RTSR Workform for Electricity Distributors (2013 Filers)

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing deter minants on Sheet "4. RRR Data". For Hydro One Sub-transmission Rates, if you are charged a *combined* Line and Transformer connection rate, please ensure that both the line connection and transformer connection columns are completed.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	16,650	$3.22	$ 53,613	17,140	$0.79	$ 13,541	17,140	$1.77	$ 30,338	$ 43,878
February	16,996	$3.22	$ 54,727	17,672	$0.79	$ 13,961	17,672	$1.77	$ 31,279	$ 45,240
March	18,192	$3.22	$ 58,578	18,192	$0.79	$ 14,372	18,192	$1.77	$ 32,200	$ 46,572
April	8,038	$3.22	$ 25,882	9,614	$0.79	$ 7,595	9,614	$1.77	$ 17,017	$ 24,612
May	8,659	$3.22	$ 27,882	10,436	$0.79	$ 8,244	10,436	$1.77	$ 18,472	$ 26,716
June	9,863	$3.22	$ 31,759	10,486	$0.79	$ 8,284	10,486	$1.77	$ 18,560	$ 26,844
July	10,139	$3.22	$ 32,648	11,205	$0.79	$ 8,852	11,205	$1.77	$ 19,833	$ 28,685
August	9,870	$3.22	$ 31,781	10,967	$0.79	$ 8,664	10,967	$1.77	$ 19,412	$ 28,076
September	14,980	$3.22	$ 48,236	18,716	$0.79	$ 14,786	18,716	$1.77	$ 33,127	$ 47,913
October	8,276	$3.22	$ 26,649	9,736	$0.79	$ 7,691	9,736	$1.77	$ 17,233	$ 24,924
November	9,917	$3.22	$ 31,933	10,800	$0.79	$ 8,532	10,800	$1.77	$ 19,116	$ 27,648
December	8,373	$3.22	$ 26,961	9,850	$0.79	$ 7,782	9,850	$1.77	$ 17,435	$ 25,216
Total	139,953	$ 3.22	$ 450,649	154,814	$ 0.79	$ 122,303	154,814	$ 1.77	$ 274,021	$ 396,324

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	70,620	$2.65	$ 187,143	70,620	$0.64	$ 45,197	70,620	$1.50	$ 105,930	$ 151,127
February	78,382	$2.65	$ 207,712	78,404	$0.64	$ 50,179	78,404	$1.50	$ 117,606	$ 167,785
March	71,682	$2.65	$ 189,957	72,931	$0.64	$ 46,676	72,931	$1.50	$ 109,397	$ 156,072
April	65,501	$2.65	$ 173,578	68,008	$0.64	$ 43,525	68,008	$1.50	$ 102,012	$ 145,537
May	84,192	$2.65	$ 223,109	84,383	$0.64	$ 54,005	84,383	$1.50	$ 126,575	$ 180,580
June	90,748	$2.65	$ 240,482	90,748	$0.64	$ 58,079	90,748	$1.50	$ 136,122	$ 194,201
July	101,452	$2.65	$ 268,848	101,890	$0.64	$ 65,210	101,890	$1.50	$ 152,835	$ 218,045
August	83,183	$2.65	$ 220,435	84,112	$0.64	$ 53,832	84,112	$1.50	$ 126,168	$ 180,000
September	72,921	$2.65	$ 193,241	73,128	$0.64	$ 46,802	73,128	$1.50	$ 109,692	$ 156,494
October	67,151	$2.65	$ 177,950	69,247	$0.64	$ 44,318	69,247	$1.50	$ 103,871	$ 148,189
November	73,997	$2.65	$ 196,092	75,152	$0.64	$ 48,097	75,152	$1.50	$ 112,728	$ 160,825
December	78,114	$2.65	$ 207,002	79,133	$0.64	$ 50,645	79,133	$1.50	$ 118,700	$ 169,345
Total	937,943	$ 2.65	$ 2,485,549	947,756	$ 0.64	$ 606,564	947,756	$ 1.50	$ 1,421,634	$ 2,028,198

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	87,270	$2.76	$ 240,756	87,760	$0.67	$ 58,737	87,760	$1.55	$ 136,268	$ 195,005
February	95,378	$2.75	$ 262,439	96,076	$0.67	$ 64,139	96,076	$1.55	$ 148,885	$ 213,025
March	89,874	$2.77	$ 248,536	91,123	$0.67	$ 61,048	91,123	$1.55	$ 141,596	$ 202,644
April	73,539	$2.71	$ 199,460	77,622	$0.66	$ 51,120	77,622	$1.53	$ 119,029	$ 170,149
May	92,851	$2.70	$ 250,991	94,819	$0.66	$ 62,250	94,819	$1.53	$ 145,046	$ 207,296
June	100,611	$2.71	$ 272,241	101,234	$0.66	$ 66,363	101,234	$1.53	$ 154,682	$ 221,045
July	111,591	$2.70	$ 301,495	113,095	$0.65	$ 74,062	113,095	$1.53	$ 172,668	$ 246,729
August	93,053	$2.71	$ 252,216	95,079	$0.66	$ 62,496	95,079	$1.53	$ 145,580	$ 208,075
September	87,901	$2.75	$ 241,476	91,844	$0.67	$ 61,588	91,844	$1.56	$ 142,819	$ 204,407
October	75,427	$2.71	$ 204,599	78,983	$0.66	$ 52,010	78,983	$1.53	$ 121,103	$ 173,113
November	83,914	$2.72	$ 228,025	85,952	$0.66	$ 56,629	85,952	$1.53	$ 131,844	$ 188,473
December	86,487	$2.71	$ 233,963	88,983	$0.66	$ 58,427	88,983	$1.53	$ 136,134	$ 194,561
Total	1,077,896	$ 2.72	$ 2,936,198	1,102,570	$ 0.66	$ 728,867	1,102,570	$ 1.54	$ 1,695,655	$ 2,424,522

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to calculate the expected billing when current 2012 Uniform Transmission Rates are applied against historical 2011 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	16,650	$ 3.5700	$ 59,441	17,140	$ 0.8000	$ 13,712	17,140	$ 1.8600	$ 31,880	$ 45,592
February	16,996	$ 3.5700	$ 60,676	17,672	$ 0.8000	$ 14,138	17,672	$ 1.8600	$ 32,870	$ 47,008
March	18,192	$ 3.5700	$ 64,945	18,192	$ 0.8000	$ 14,554	18,192	$ 1.8600	$ 33,837	$ 48,391
April	8,038	$ 3.5700	$ 28,696	9,614	$ 0.8000	$ 7,691	9,614	$ 1.8600	$ 17,882	$ 25,573
May	8,659	$ 3.5700	$ 30,913	10,436	$ 0.8000	$ 8,349	10,436	$ 1.8600	$ 19,411	$ 27,760
June	9,863	$ 3.5700	$ 35,211	10,486	$ 0.8000	$ 8,389	10,486	$ 1.8600	$ 19,504	$ 27,893
July	10,139	$ 3.5700	$ 36,196	11,205	$ 0.8000	$ 8,964	11,205	$ 1.8600	$ 20,841	$ 29,805
August	9,870	$ 3.5700	$ 35,236	10,967	$ 0.8000	$ 8,774	10,967	$ 1.8600	$ 20,399	$ 29,172
September	14,980	$ 3.5700	$ 53,479	18,716	$ 0.8000	$ 14,973	18,716	$ 1.8600	$ 34,812	$ 49,785
October	8,276	$ 3.5700	$ 29,545	9,736	$ 0.8000	$ 7,789	9,736	$ 1.8600	$ 18,109	$ 25,898
November	9,917	$ 3.5700	$ 35,404	10,800	$ 0.8000	$ 8,640	10,800	$ 1.8600	$ 20,088	$ 28,728
December	8,373	$ 3.5700	$ 29,892	9,850	$ 0.8000	$ 7,880	9,850	$ 1.8600	$ 18,321	$ 26,201
Total	139,953	$ 3.57	$ 499,632	154,814	$ 0.80	$ 123,851	154,814	$ 1.86	$ 287,954	$ 411,805

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	70,620	$ 2.6500	$ 187,143	70,620	$ 0.6400	$ 45,197	70,620	$ 1.5000	$ 105,930	$ 151,127
February	78,382	$ 2.6500	$ 207,712	78,404	$ 0.6400	$ 50,179	78,404	$ 1.5000	$ 117,606	$ 167,785
March	71,682	$ 2.6500	$ 189,957	72,931	$ 0.6400	$ 46,676	72,931	$ 1.5000	$ 109,397	$ 156,072
April	65,501	$ 2.6500	$ 173,578	68,008	$ 0.6400	$ 43,525	68,008	$ 1.5000	$ 102,012	$ 145,537
May	84,192	$ 2.6500	$ 223,109	84,383	$ 0.6400	$ 54,005	84,383	$ 1.5000	$ 126,575	$ 180,580
June	90,748	$ 2.6500	$ 240,482	90,748	$ 0.6400	$ 58,079	90,748	$ 1.5000	$ 136,122	$ 194,201
July	101,452	$ 2.6500	$ 268,848	101,890	$ 0.6400	$ 65,210	101,890	$ 1.5000	$ 152,835	$ 218,045
August	83,183	$ 2.6500	$ 220,435	84,112	$ 0.6400	$ 53,832	84,112	$ 1.5000	$ 126,168	$ 180,000
September	72,921	$ 2.6500	$ 193,241	73,128	$ 0.6400	$ 46,802	73,128	$ 1.5000	$ 109,692	$ 156,494
October	67,151	$ 2.6500	$ 177,950	69,247	$ 0.6400	$ 44,318	69,247	$ 1.5000	$ 103,871	$ 148,189
November	73,997	$ 2.6500	$ 196,092	75,152	$ 0.6400	$ 48,097	75,152	$ 1.5000	$ 112,728	$ 160,825
December	78,114	$ 2.6500	$ 207,002	79,133	$ 0.6400	$ 50,645	79,133	$ 1.5000	$ 118,700	$ 169,345
Total	937,943	$ 2.65	$ 2,485,549	947,756	$ 0.64	$ 606,564	947,756	$ 1.50	$ 1,421,634	$ 2,028,198

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	87,270	$ 2.83	$ 246,584	87,760	$ 0.67	$ 58,909	87,760	$ 1.57	$ 137,810	$ 196,719
February	95,378	$ 2.81	$ 268,388	96,076	$ 0.67	$ 64,316	96,076	$ 1.57	$ 150,476	$ 214,792
March	89,874	$ 2.84	$ 254,903	91,123	$ 0.67	$ 61,229	91,123	$ 1.57	$ 143,234	$ 204,463
April	73,539	$ 2.75	$ 202,273	77,622	$ 0.66	$ 51,216	77,622	$ 1.54	$ 119,894	$ 171,110
May	92,851	$ 2.74	$ 254,021	94,819	$ 0.66	$ 62,354	94,819	$ 1.54	$ 145,985	$ 208,339
June	100,611	$ 2.74	$ 275,693	101,234	$ 0.66	$ 66,468	101,234	$ 1.54	$ 155,626	$ 222,093
July	111,591	$ 2.73	$ 305,044	113,095	$ 0.66	$ 74,174	113,095	$ 1.54	$ 173,676	$ 247,850
August	93,053	$ 2.75	$ 255,671	95,079	$ 0.66	$ 62,605	95,079	$ 1.54	$ 146,567	$ 209,172
September	87,901	$ 2.81	$ 246,719	91,844	$ 0.67	$ 61,775	91,844	$ 1.57	$ 144,504	$ 206,278
October	75,427	$ 2.75	$ 207,495	78,983	$ 0.66	$ 52,107	78,983	$ 1.54	$ 121,979	$ 174,086
November	83,914	$ 2.76	$ 231,496	85,952	$ 0.66	$ 56,737	85,952	$ 1.55	$ 132,816	$ 189,553
December	86,487	$ 2.74	$ 236,894	88,983	$ 0.66	$ 58,525	88,983	$ 1.54	$ 137,021	$ 195,546
Total	1,077,896	$ 2.77	$ 2,985,181	1,102,570	$ 0.66	$ 730,415	1,102,570	$ 1.55	$ 1,709,588	$ 2,440,003

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to calculate the expected billing when forecasted 2013 Uniform Transmission Rates are applied against historical 2011 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	16,650	$ 3.5700	$ 59,441	17,140	$ 0.8000	$ 13,712	17,140	$ 1.8600	$ 31,880	$ 45,592
February	16,996	$ 3.5700	$ 60,676	17,672	$ 0.8000	$ 14,138	17,672	$ 1.8600	$ 32,870	$ 47,008
March	18,192	$ 3.5700	$ 64,945	18,192	$ 0.8000	$ 14,554	18,192	$ 1.8600	$ 33,837	$ 48,391
April	8,038	$ 3.5700	$ 28,696	9,614	$ 0.8000	$ 7,691	9,614	$ 1.8600	$ 17,882	$ 25,573
May	8,659	$ 3.5700	$ 30,913	10,436	$ 0.8000	$ 8,349	10,436	$ 1.8600	$ 19,411	$ 27,760
June	9,863	$ 3.5700	$ 35,211	10,486	$ 0.8000	$ 8,389	10,486	$ 1.8600	$ 19,504	$ 27,893
July	10,139	$ 3.5700	$ 36,196	11,205	$ 0.8000	$ 8,964	11,205	$ 1.8600	$ 20,841	$ 29,805
August	9,870	$ 3.5700	$ 35,236	10,967	$ 0.8000	$ 8,774	10,967	$ 1.8600	$ 20,399	$ 29,172
September	14,980	$ 3.5700	$ 53,479	18,716	$ 0.8000	$ 14,973	18,716	$ 1.8600	$ 34,812	$ 49,785
October	8,276	$ 3.5700	$ 29,545	9,736	$ 0.8000	$ 7,789	9,736	$ 1.8600	$ 18,109	$ 25,898
November	9,917	$ 3.5700	$ 35,404	10,800	$ 0.8000	$ 8,640	10,800	$ 1.8600	$ 20,088	$ 28,728
December	8,373	$ 3.5700	$ 29,892	9,850	$ 0.8000	$ 7,880	9,850	$ 1.8600	$ 18,321	$ 26,201
Total	139,953	$ 3.57	$ 499,632	154,814	$ 0.80	$ 123,851	154,814	$ 1.86	$ 287,954	$ 411,805

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	70,620	$ 2.6500	$ 187,143	70,620	$ 0.6400	$ 45,197	70,620	$ 1.5000	$ 105,930	$ 151,127
February	78,382	$ 2.6500	$ 207,712	78,404	$ 0.6400	$ 50,179	78,404	$ 1.5000	$ 117,606	$ 167,785
March	71,682	$ 2.6500	$ 189,957	72,931	$ 0.6400	$ 46,676	72,931	$ 1.5000	$ 109,397	$ 156,072
April	65,501	$ 2.6500	$ 173,578	68,008	$ 0.6400	$ 43,525	68,008	$ 1.5000	$ 102,012	$ 145,537
May	84,192	$ 2.6500	$ 223,109	84,383	$ 0.6400	$ 54,005	84,383	$ 1.5000	$ 126,575	$ 180,580
June	90,748	$ 2.6500	$ 240,482	90,748	$ 0.6400	$ 58,079	90,748	$ 1.5000	$ 136,122	$ 194,201
July	101,452	$ 2.6500	$ 268,848	101,890	$ 0.6400	$ 65,210	101,890	$ 1.5000	$ 152,835	$ 218,045
August	83,183	$ 2.6500	$ 220,435	84,112	$ 0.6400	$ 53,832	84,112	$ 1.5000	$ 126,168	$ 180,000
September	72,921	$ 2.6500	$ 193,241	73,128	$ 0.6400	$ 46,802	73,128	$ 1.5000	$ 109,692	$ 156,494
October	67,151	$ 2.6500	$ 177,950	69,247	$ 0.6400	$ 44,318	69,247	$ 1.5000	$ 103,871	$ 148,189
November	73,997	$ 2.6500	$ 196,092	75,152	$ 0.6400	$ 48,097	75,152	$ 1.5000	$ 112,728	$ 160,825
December	78,114	$ 2.6500	$ 207,002	79,133	$ 0.6400	$ 50,645	79,133	$ 1.5000	$ 118,700	$ 169,345
Total	937,943	$ 2.65	$ 2,485,549	947,756	$ 0.64	$ 606,564	947,756	$ 1.50	$ 1,421,634	$ 2,028,198

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	87,270	$ 2.83	$ 246,584	87,760	$ 0.67	$ 58,909	87,760	$ 1.57	$ 137,810	$ 196,719
February	95,378	$ 2.81	$ 268,388	96,076	$ 0.67	$ 64,316	96,076	$ 1.57	$ 150,476	$ 214,792
March	89,874	$ 2.84	$ 254,903	91,123	$ 0.67	$ 61,229	91,123	$ 1.57	$ 143,234	$ 204,463
April	73,539	$ 2.75	$ 202,273	77,622	$ 0.66	$ 51,216	77,622	$ 1.54	$ 119,894	$ 171,110
May	92,851	$ 2.74	$ 254,021	94,819	$ 0.66	$ 62,354	94,819	$ 1.54	$ 145,985	$ 208,339
June	100,611	$ 2.74	$ 275,693	101,234	$ 0.66	$ 66,468	101,234	$ 1.54	$ 155,626	$ 222,093
July	111,591	$ 2.73	$ 305,044	113,095	$ 0.66	$ 74,174	113,095	$ 1.54	$ 173,676	$ 247,850
August	93,053	$ 2.75	$ 255,671	95,079	$ 0.66	$ 62,605	95,079	$ 1.54	$ 146,567	$ 209,172
September	87,901	$ 2.81	$ 246,719	91,844	$ 0.67	$ 61,775	91,844	$ 1.57	$ 144,504	$ 206,278
October	75,427	$ 2.75	$ 207,495	78,983	$ 0.66	$ 52,107	78,983	$ 1.54	$ 121,979	$ 174,086
November	83,914	$ 2.76	$ 231,496	85,952	$ 0.66	$ 56,737	85,952	$ 1.55	$ 132,816	$ 189,553
December	86,487	$ 2.74	$ 236,894	88,983	$ 0.66	$ 58,525	88,983	$ 1.54	$ 137,021	$ 195,546
Total	1,077,896	$ 2.77	$ 2,985,181	1,102,570	$ 0.66	$ 730,415	1,102,570	$ 1.55	$ 1,709,588	$ 2,440,003

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to re-align the current RTS Network Rates to recover current wholesale network costs.

Rate Class	Unit	Current RTSR-Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR Network
Residential - Time of Use	kWh	$ 0.0057	226,642,977	-	$ 1,291,865	43.3%	$ 1,292,112	$ 0.0057
General Service Less Than 50 kW	kWh	$ 0.0051	60,857,101	-	$ 310,371	10.4%	$ 310,431	$ 0.0051
General Service 50 to 999 kW	kW	$ 2.2257	115,214,051	318,520	$ 708,930	23.8%	$ 709,066	$ 2.2261
General Service 1,000 to 4,999 kW - Interval Meters	kW	$ 2.2257	105,252,631	294,618	$ 655,731	22.0%	$ 655,857	$ 2.2261
Unmetered Scattered Load	kWh	$ 0.0051	945,354	-	$ 4,821	0.2%	$ 4,822	$ 0.0051
Sentinel Lighting	kW	$ 1.5878	503,097	520	$ 826	0.0%	$ 826	$ 1.5881
Street Lighting	kW	$ 1.5805	2,743,202	7,634	$ 12,066	0.4%	$ 12,068	$ 1.5808
					$ 2,984,610			

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to re-align the current RTS Connection Rates to recover current wholesale connection costs.

Rate Class	Unit	Current RTSR-Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR Connection
Residential - Time of Use	kWh	$ 0.0045	226,642,977	-	$ 1,019,893	42.6%	$ 1,040,392	$ 0.0046
General Service Less Than 50 kW	kWh	$ 0.0042	60,857,101	-	$ 255,600	10.7%	$ 260,737	$ 0.0043
General Service 50 to 999 kW	kW	$ 1.7975	115,214,051	318,520	$ 572,540	23.9%	$ 584,047	$ 1.8336
General Service 1,000 to 4,999 kW - Interval Meters	kW	$ 1.7975	105,252,631	294,618	$ 529,576	22.1%	$ 540,219	$ 1.8336
Unmetered Scattered Load	kWh	$ 0.0042	945,354	-	$ 3,970	0.2%	$ 4,050	$ 0.0043
Sentinel Lighting	kW	$ 1.2941	503,097	520	$ 673	0.0%	$ 686	$ 1.3201
Street Lighting	kW	$ 1.2676	2,743,202	7,634	$ 9,677	0.4%	$ 9,871	$ 1.2931
					$ 2,391,929			

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to update the re-align RTS Network Rates to recover forecast wholesale network costs.

Rate Class	Unit	Adjusted RTSR-Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Network
Residential - Time of Use	kWh	$ 0.0057	226,642,977	-	$ 1,292,112	43.3%	$ 1,292,112	$ 0.0057
General Service Less Than 50 kW	kWh	$ 0.0051	60,857,101	-	$ 310,431	10.4%	$ 310,431	$ 0.0051
General Service 50 to 999 kW	kW	$ 2.2261	115,214,051	318,520	$ 709,066	23.8%	$ 709,066	$ 2.2261
General Service 1,000 to 4,999 kW - Interval Meters	kW	$ 2.2261	105,252,631	294,618	$ 655,857	22.0%	$ 655,857	$ 2.2261
Unmetered Scattered Load	kWh	$ 0.0051	945,354	-	$ 4,822	0.2%	$ 4,822	$ 0.0051
Sentinel Lighting	kW	$ 1.5881	503,097	520	$ 826	0.0%	$ 826	$ 1.5881
Street Lighting	kW	$ 1.5808	2,743,202	7,634	$ 12,068	0.4%	$ 12,068	$ 1.5808
					$ 2,985,181			

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to update the re-aligned RTS Connection Rates to recover forecast wholesale connection costs.

Rate Class	Unit	Adjusted RTSR-Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Connection
Residential - Time of Use	kWh	$ 0.0046	226,642,977	-	$ 1,040,392	42.6%	$ 1,040,392	$ 0.0046
General Service Less Than 50 kW	kWh	$ 0.0043	60,857,101	-	$ 260,737	10.7%	$ 260,737	$ 0.0043
General Service 50 to 999 kW	kW	$ 1.8336	115,214,051	318,520	$ 584,047	23.9%	$ 584,047	$ 1.8336
General Service 1,000 to 4,999 kW - Interval Meters	kW	$ 1.8336	105,252,631	294,618	$ 540,219	22.1%	$ 540,219	$ 1.8336
Unmetered Scattered Load	kWh	$ 0.0043	945,354	-	$ 4,050	0.2%	$ 4,050	$ 0.0043
Sentinel Lighting	kW	$ 1.3201	503,097	520	$ 686	0.0%	$ 686	$ 1.3201
Street Lighting	kW	$ 1.2931	2,743,202	7,634	$ 9,871	0.4%	$ 9,871	$ 1.2931
					$ 2,440,003			

RTSR Workform for Electricity Distributors (2013 Filers)

For Cost of Service Applicants, please enter the following Proposed RTS rates into your rates model.

For IRM applicants, please enter these rates into the 2013 IRM Rate Generator, Sheet 11 "Proposed Rates", column I. Please note that the rate description for the RTSRs has been transfered to Sheet 11, Column A from Sheet 4.

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Residential - Time of Use	kWh	$ 0.0057	$ 0.0046
General Service Less Than 50 kW	kWh	$ 0.0051	$ 0.0043
General Service 50 to 999 kW	kW	$ 2.2261	$ 1.8336
General Service 1,000 to 4,999 kW - Interval Meters	kW	$ 2.2261	$ 1.8336
Unmetered Scattered Load	kWh	$ 0.0051	$ 0.0043
Sentinel Lighting	kW	$ 1.5881	$ 1.3201
Street Lighting	kW	$ 1.5808	$ 1.2931

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Appendix C

2013_IRM_Revenue_CostRatioAdj_Workform_V2_20120628

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3RD Generation Incentive Regulation Revenue to Cost Ratio Adjustment Model for 2013 Filers

Utility Name	Halton Hills Hydro Inc.
Assigned EB Number	EB-2012-0130
Name and Title	David Smelsky, Chief Financial Officer
Phone Number	519-853-3700 ext 208
Email Address	dsmelsky@haltonhillshydro.com
Date	12-Oct-12
Last COS Re-based Year	**2012**

3^{RD} Generation Incentive Regulation Revenue to Cost Ratio Adjustment Model for 2013 Filers

3^{RD} Generation Incentive Regulation Revenue to Cost Ratio Adjustment Model for 2013 Filers

The purpose of this sheet is to set up the rate classes, enter the re-based billing determinants from your last cost of service application and enter the current service charge and volumetric distribution rates as found on your May 1, 2012 (or subsequent) Tariff of rates and charges.

Rate Group	Rate Class	Fixed Metric	Vol Metric	Re-based Billed Customers or Connections A	Re-based Billed kWh B	Re-based Billed kW C	Current Tariff Service Charge D	Current Tariff Distribution Volumetric Rate kWh E	Current Tariff Distribution Volumetric Rate kW F
RES	Residential - Time of Use	Customer	kWh	19,530	210,212,474		12.25	0.0115	
GSLT50	General Service Less Than 50 kW	Customer	kWh	1,694	54,285,767		26.50	0.0083	
GSGT50	General Service 50 to 999 kW	Customer	kW	176	117,338,024	328,299	74.64		3.3287
GSGT50	General Service 1,000 to 4,999 kW - Interval Meter	Customer	kW	13	108,192,394	293,909	173.31		3.0517
USL	Unmetered Scattered Load	Connection	kWh	175	838,540		6.50	0.0043	
Sen	Sentinel Lighting	Connection	kW	175	380,342	810	4.88		18.4557
SL	Street Lighting	Connection	kW	4,474	2,778,881	7,820	2.14		28.9538
NA	Rate Class 8	NA	NA						
NA	Rate Class 9	NA	NA						
NA	Rate Class 10	NA	NA						
NA	Rate Class 11	NA	NA						
NA	Rate Class 12	NA	NA						
NA	Rate Class 13	NA	NA						
NA	Rate Class 14	NA	NA						
NA	Rate Class 15	NA	NA						
NA	Rate Class 16	NA	NA						
NA	Rate Class 17	NA	NA						
NA	Rate Class 18	NA	NA						
NA	Rate Class 19	NA	NA						
NA	Rate Class 20	NA	NA						
NA	Rate Class 21	NA	NA						
NA	Rate Class 22	NA	NA						
NA	Rate Class 23	NA	NA						
NA	Rate Class 24	NA	NA						
NA	Rate Class 25	NA	NA						

3RD Generation Incentive Regulation Revenue to Cost Ratio Adjustment Model for 2013 Filers

The purpose of this sheet is to remove any rate adders included in current rates. Most applicants will not need to make an entry on this sheet.

Rate Class	Current Tariff Service Charge A	Current Tariff Distribution Volumetric Rate kWh B	Current Tariff Distribution Volumetric Rate kW C	Service Charge Rate Adders D	Distribution Volumetric kWh Rate Adders E	Distribution Volumetric kW Rate Adders F
Residential - Time of Use	12.25	0.0115	0.0000	0.00	0.0000	0.0000
General Service Less Than 50 kW	26.50	0.0083	0.0000	0.00	0.0000	0.0000
General Service 50 to 999 kW	74.64	0.0000	3.3287	0.00	0.0000	0.0000
General Service 1,000 to 4,999 kW - Interval Meters	173.31	0.0000	3.0517	0.00	0.0000	0.0000
Unmetered Scattered Load	6.50	0.0043	0.0000	0.00	0.0000	0.0000
Sentinel Lighting	4.88	0.0000	18.4557	0.00	0.0000	0.0000
Street Lighting	2.14	0.0000	28.9538	0.00	0.0000	0.0000

3RD Generation Incentive Regulation Revenue to Cost Ratio Adjustment Model for 2013 Filers

The purpose of this sheet is to calculate current revenue from rate classes.

Rate Class	Re-based Billed Customers or Connections A	Re-based Billed kWh B	Re-based Billed kW C	Current Base Service Charge D	Current Base Distribution Volumetric Rate kWh E	Current Base Distribution Volumetric Rate kW F	Service Charge Revenue G = A * D *12	Distribution Volumetric Rate Revenue kWh H = B * E	Distribution Volumetric Rate Revenue kW I = C * F	Revenue Requirement from Rates I
Residential - Time of Use	19,530	210,212,474	0	12.25	0.0115	0.0000	2,870,910	2,417,443	0	5,288,353
General Service Less Than 50 kW	1,694	54,285,767	0	26.50	0.0083	0.0000	538,692	450,572	0	989,264
General Service 50 to 999 kW	176	117,338,024	328,299	74.64	0.0000	3.3287	157,640	0	1,092,809	1,250,449
Interval Meters	13	108,192,394	293,909	173.31	0.0000	3.0517	27,036	0	896,922	923,958
Unmetered Scattered Load	175	838,540	0	6.50	0.0043	0.0000	13,650	3,606	0	17,256
Sentinel Lighting	175	380,342	810	4.88	0.0000	18.4557	10,248	0	14,949	25,197
Street Lighting	4,474	2,778,881	7,820	2.14	0.0000	28.9538	114,892	0	226,419	341,311
							3,733,068	2,871,621	2,231,099	8,835,788

3RD Generation Incentive Regulation Revenue to Cost Ratio Adjustment Model for 2013 Filers

The purpose of this sheet is to enter the Revenue Cost Ratios as determined from column G on Sheet "10. Proposed R C Ratio Adj" of the applicant's 2012 IRM3 Supplemental Filing Module or 2012 COS Decision and Order.

Under the column labeled "Direction", the applicant can choose "No Change" (i.e: no change in that rate class ratio), "Change" (i.e: Board ordered change from COS decision) or "Rebalance" (i.e: to apply any offset adjustments required).

Rate Class	**Direction**	Current Year 2012	Transition Year 1 2013	Transition Year 2 2014	Transition Year 3 2015	Transition Year 4 2016	Transition Year 5 2017
Residential - Time of Use	No Change	96.00%	96.00%	96.00%	96.00%	96.00%	96.00%
General Service Less Than 50 kW	No Change	110.00%	110.00%	110.00%	110.00%	110.00%	110.00%
General Service 50 to 999 kW	No Change	96.00%	96.00%	96.00%	96.00%	96.00%	96.00%
General Service 1,000 to 4,999 kW - Interval Meters	No Change	120.00%	120.00%	120.00%	120.00%	120.00%	120.00%
Unmetered Scattered Load	No Change	120.00%	120.00%	120.00%	120.00%	120.00%	120.00%
Sentinel Lighting	No Change	96.00%	96.00%	96.00%	96.00%	96.00%	96.00%
Street Lighting	No Change	120.00%	120.00%	120.00%	120.00%	120.00%	120.00%

3RD Generation Incentive Regulation Revenue to Cost Ratio Adjustment Model for 2013 Filers

The purpose of this sheet is to allocate the Revenue Offsets (miscellaneous revenue, cell F47) found in the last COS to the various rate classes in proportion to the allocation from the Cost Allocation informational filing.

Rate Class	Informational Filing Revenue Offsets A	Percentage Split C= A / B	Allocated Revenue Offsets E = D * C
Residential - Time of Use	782,324	67.50%	782,323
General Service Less Than 50 kW	183,918	15.87%	183,918
General Service 50 to 999 kW	108,387	9.35%	108,387
General Service 1,000 to 4,999 kW - Interval Meters	40,714	3.51%	40,714
Unmetered Scattered Load	1,823	0.16%	1,823
Sentinel Lighting	3,348	0.29%	3,348
Street Lighting	38,532	3.32%	38,532
	1,159,046	100.00%	1,159,045
	B		D

3^{RD} Generation Incentive Regulation Revenue to Cost Ratio Adjustment Model for 2013 Filers

The purpose of this sheet is to remove the transformer allowance from volumetric rates. In Cell E47, enter your Transformer Allowance as per your 2012 IRM3 Supplemental Filing Module or your last CoS Decision. Under the column labeled "Transformer Allowance in Rates" select "Yes" if included in that rate class or "No" if not included. Once selected, apply the update button to reveal input cells in which you can enter the number of kW's and the transfromer rate for each rate class.

Rate Class	Transformer Allowance In Rate	Transformer Allowance	Transformer Allowance kW's	Transformer Allowance Rate	Volumetric Distribution Rate	Billed kW's	Adjusted Volumetric Distribution Rate
		A	C	E	F	G	I =(F * (G - C) + (F - E) * C) / G
Residential - Time of Use	No						
General Service Less Than 50 kW	No						
General Service 50 to 999 kW	Yes	(57,229)	114,458	(0.5000)	3.3287	328,299	3.5030
General Service 1,000 to 4,999 kW - Interval Meters	Yes	(150,229)	300,458	(0.5000)	3.0517	293,909	3.5628
Unmetered Scattered Load	No						
Sentinel Lighting	No						
Street Lighting	No						
		- 207,458	414,916			622,208	
		B	D			H	
		-					

The purpose of this sheet is to calculate revenue by rate class that inlcudes Revenue Offsets and excludes Transformer Allowance prior to Revenue Cost Ratio Adjustment re-allocation.

Rate Class	Billed Customers or Connections A	Billed kWh B	Billed kW C		Base Service Charge D	Base Distribution Volumetric Rate kWh E	Base Distribution Volumetric Rate kW F	Service Charge *12	Distribution Volumetric Rate kWh H = B * E	Distribution Volumetric Rate kW I = C * F	Revenue Requirement from Rates J = G + H + I
Residential - Time of Use	19,530	210,212,474	0	0	12.25	0.0115	0.0000	2,870,910	2,417,443	0	5,288,353
General Service Less Than 50 kW	1,694	54,285,767	0	0	26.50	0.0083	0.0000	538,692	450,572	0	989,264
General Service 50 to 999 kW	176	117,338,024	328,299	0	74.64	0.0000	3.5030	157,640	0	1,150,038	1,307,678
General Service 1,000 to 4,999 kW - Interval Meters	13	108,192,394	293,909	0	173.31	0.0000	3.5628	27,036	0	1,047,151	1,074,187
Unmetered Scattered Load	175	838,540	0	0	6.50	0.0043	0.0000	13,650	3,606	0	17,256
Sentinel Lighting	175	380,342	810	0	4.88	0.0000	18.4557	10,248	0	14,949	25,197
Street Lighting	4,474	2,778,881	7,820	0	2.14	0.0000	28.9538	114,892	0	226,419	341,311
								3,733,068	2,871,621	2,438,557	9,043,246

Proposed Revenue Cost Ratio Adjustment

Rate Class	Adjusted Revenue A	Current Revenue Cost Ratio B	Re-Allocated Cost C = A / B	Proposed Revenue Cost Ratio D	Final Adjusted Revenue E = C * D	Dollar Change F = E - C	Percentage Change G = (E / C) - 1
Residential - Time of Use	$ 6,070,677	0.96	$ 6,323,622	0.96	$ 6,070,677	-$ 0	0.0%
General Service Less Than 50 kW	$ 1,173,182	1.10	$ 1,066,529	1.10	$ 1,173,182	$ 0	0.0%
General Service 50 to 999 kW	$ 1,416,064	0.96	$ 1,475,067	0.96	$ 1,416,064	-$ 0	0.0%
General Service 1,000 to 4,999 kW - I	$ 1,114,901	1.20	$ 929,085	1.20	$ 1,114,901	$ 0	0.0%
Unmetered Scattered Load	$ 19,079	1.20	$ 15,899	1.20	$ 19,079	$ 0	0.0%
Sentinel Lighting	$ 28,545	0.96	$ 29,734	0.96	$ 28,545	-$ 0	0.0%
Street Lighting	$ 379,843	1.20	$ 316,536	1.20	$ 379,843	$ 0	0.0%
	$ 10,202,291		$ 10,156,471		$ 10,202,291	-$ 0	0.0%

Out of Balance **0**

Final ? Yes

Proposed Revenue from Revenue Cost Ratio Adjustment

Rate Class	Adjusted Revenue By Revenue Cost Ratio A	Allocated Re-Based Revenue Offsets B	Revenue Requirement from Rates Before Transformer Allowance C = A - B	Re-based Transformer Allowance D	Revenue Requirement from Rates E = C + D
Residential - Time of Use	$ 6,070,677	$ 782,323	$ 5,288,353	$ -	$ 5,288,353
General Service Less Than 50 kW	$ 1,173,182	$ 183,918	$ 989,264	$ -	$ 989,264
General Service 50 to 999 kW	$ 1,416,064	$ 108,387	$ 1,307,678	-$ 57,229	$ 1,250,449
General Service 1,000 to 4,999 kW - Interval Meters	$ 1,114,901	$ 40,714	$ 1,074,187	-$ 150,229	$ 923,958
Unmetered Scattered Load	$ 19,079	$ 1,823	$ 17,256	$ -	$ 17,256
Sentinel Lighting	$ 28,545	$ 3,348	$ 25,197	$ -	$ 25,197
Street Lighting	$ 379,843	$ 38,532	$ 341,311	$ -	$ 341,311
	$ 10,202,291	$ 1,159,045	$ 9,043,246	-$ 207,458	$ 8,835,788

Proposed fixed and variable revenue allocation

Rate Class	Revenue Requirement from Rates A	Service Charge % Revenue B	Distribution Volumetric Rate % Revenue kWh C	Distribution Volumetric Rate % Revenue kW D	Service Charge Revenue E = A * B	Distribution Volumetric Rate Revenue kWh F = A * C	Distribution Volumetric Rate Revenue kW G = A * D	Revenue Requirement from Rates by Rate Class H = E + F + G
Residential - Time of Use	$ 5,288,353	54.3%	45.7%	0.0%	$ 2,870,910	$ 2,417,443	$ -	$ 5,288,353
General Service Less Than 50 kW	$ 989,264	54.5%	45.5%	0.0%	$ 538,692	$ 450,572	$ -	$ 989,264
General Service 50 to 999 kW	$ 1,250,449	12.6%	0.0%	87.4%	$ 157,640	$ -	$ 1,092,809	$ 1,250,449
General Service 1,000 to 4,999 kW - I	$ 923,958	2.9%	0.0%	97.1%	$ 27,036	$ -	$ 896,922	$ 923,958
Unmetered Scattered Load	$ 17,256	79.1%	20.9%	0.0%	$ 13,650	$ 3,606	$ -	$ 17,256
Sentinel Lighting	$ 25,197	40.7%	0.0%	59.3%	$ 10,248	$ -	$ 14,949	$ 25,197
Street Lighting	$ 341,311	33.7%	0.0%	66.3%	$ 114,892	$ -	$ 226,419	$ 341,311
	$ 8,835,788				$ 3,733,068	$ 2,871,621	$ 2,231,099	$ 8,835,788

3RD Generation Incentive Regulation Revenue to Cost Ratio Adjustment Model for 2013 Filers

Proposed fixed and variable rates

Rate Class	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Re-based Billed Customers or Connections	Re-based Billed kWh	Re-based Billed kW	Proposed Base Service Charge	Proposed Base Distribution Volumetric Rate kWh	Proposed Base Distribution Volumetric Rate kW
	A	B	C	D	E	F	G = A / D / 12	H = B / E	I = C / F
Residential - Time of Use	$ 2,870,910	$ 2,417,443	$ -	19,530	210,212,474	0	12.25	0.0115	-
General Service Less Than 50 kW	$ 538,692	$ 450,572	$ -	1,694	54,285,767	0	26.50	0.0083	-
General Service 50 to 999 kW	$ 157,640	$ -	$ 1,092,809	176	117,338,024	328,299	74.64	-	3.3287
General Service 1,000 to 4,999 kW - Interval Meters	$ 27,036	$ -	$ 896,922	13	108,192,394	293,909	173.31	-	3.0517
Unmetered Scattered Load	$ 13,650	$ 3,606	$ -	175	838,540	0	6.50	0.0043	-
Sentinel Lighting	$ 10,248	$ -	$ 14,949	175	380,342	810	4.88	-	18.4557
Street Lighting	$ 114,892	$ -	$ 226,419	4,474	2,778,881	7,820	2.14	-	28.9538

3RD Generation Incentive Regulation Revenue to Cost Ratio Adjustment Model for 2013 Filers

Proposed adjustments to Base Service Charge and Distribution Volumetric Rate. Enter the adjustments found in column M and N below into Sheet 9 of the 2013 IRM Rate Generator Model.

Rate Class	Proposed Base Service Charge A	Proposed Base Distribution Volumetric Rate kWh B	Proposed Base Distribution Volumetric Rate kW C	Current Base Service Charge D	Current Base Distribution Volumetric Rate kWh E	Current Base Distribution Volumetric Rate kW F	Adjustment Required Base Service Charge G = A - D	Adjustment Required Base Distribution Volumetric Rate kWh H = B - E	Adjustment Required Base Distribution Volumetric Rate kW I = C - F
Residential - Time of Use	$ 12.25	$ 0.0115	$ -	$ 12.25	$ 0.0115	$ -	$ -	$ -	$ -
General Service Less Than 50 kW	$ 26.50	$ 0.0083	$ -	$ 26.50	$ 0.0083	$ -	$ -	$ -	$ -
General Service 50 to 999 kW	$ 74.64	$ -	$ 3.3287	$ 74.64	$ -	$ 3.3287	$ -	$ -	$ -
General Service 1,000 to 4,999 kW - Interval Meters	$ 173.31	$ -	$ 3.0517	$ 173.31	$ -	$ 3.0517	$ -	$ -	$ -
Unmetered Scattered Load	$ 6.50	$ 0.0043	$ -	$ 6.50	$ 0.0043	$ -	$ -	$ -	$ -
Sentinel Lighting	$ 4.88	$ -	$ 18.4557	$ 4.88	$ -	$ 18.4557	$ -	$ -	$ -
Street Lighting	$ 2.14	$ -	$ 28.9538	$ 2.14	$ -	$ 28.9538	$ -	$ -	$ -

Appendix D

2013_IRM_Tax_Sharing_Model_V1_20120706

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3RD Generation Incentive Regulation Shared Tax Savings Model for 2013 Filers

Version 1.0

Utility Name	Halton Hills Hydro Inc.
Assigned EB Number	EB-2012-0130
Name and Title	David J. Smelsky
Phone Number	519-853-3700 ext 257
Email Address	dsmelsky@haltonhillshydro.com
Date	12-Oct-12
Last COS Re-based Year	**2012**

Note: Drop-down lists are shaded blue; Input cells are shaded green.

3RD Generation Incentive Regulation Shared Tax Savings Model for 2013 Filers

Enter your 2012 Base Monthly Fixed Charge and Distribution Volumetric Charge into columns labeled "Rate ReBal Base Service Charge" and "Rate ReBal Base Distribution Volumetric Rate kWh/kW" respectively.

Last COS Re-based Year was in 2012

Rate Group	Rate Class	Fixed Metric	Vol Metric	Re-based Billed Customers or Connections A	Re-based Billed kWh B	Re-based Billed kW C	Rate ReBal Base Service Charge D	Rate ReBal Base Distribution Volumetric Rate kWh E	Rate ReBal Base Distribution Volumetric Rate kW F
RES	Residential	Customer	kWh	19,530	210,212,474		12.25	0.0115	
GSLT50	General Service Less Than 50 kW	Customer	kWh	1,694	54,285,767		26.50	0.0083	
GSGT50	General Service 50 to 999 kW	Customer	kW	176	117,338,024	328,299	74.64		3.3287
GSGT50	General Service 1,000 to 4,999 kW - Interval Meters	Customer	kW	13	108,192,394	293,909	173.31		3.0517
USL	Unmetered Scattered Load	Connection	kWh	175	838,540		6.50	0.0043	
Sen	Sentinel Lighting	Connection	kW	175	380,342	810	4.88		18.4557
SL	Street Lighting	Connection	kW	4,474	2,778,881	7,820	2.14		28.9538
NA	Rate Class 8	NA	NA						
NA	Rate Class 9	NA	NA						
NA	Rate Class 10	NA	NA						
NA	Rate Class 11	NA	NA						
NA	Rate Class 12	NA	NA						
NA	Rate Class 13	NA	NA						
NA	Rate Class 14	NA	NA						
NA	Rate Class 15	NA	NA						
NA	Rate Class 16	NA	NA						
NA	Rate Class 17	NA	NA						
NA	Rate Class 18	NA	NA						
NA	Rate Class 19	NA	NA						
NA	Rate Class 20	NA	NA						
NA	Rate Class 21	NA	NA						
NA	Rate Class 22	NA	NA						
NA	Rate Class 23	NA	NA						
NA	Rate Class 24	NA	NA						
NA	Rate Class 25	NA	NA						

3RD Generation Incentive Regulation Shared Tax Savings Model for 2013 Filers

Calculating Re-Based Revenue from rates. No input required.

Last COS Re-based Year was in 2012

Rate Class	Re-based Billed Customers or Connections A	Re-based Billed kWh B	Re-based Billed kW C	Rate ReBal Base Service Charge D	Rate ReBal Base Distribution Volumetric Rate kWh E	Rate ReBal Base Distribution Volumetric Rate kW F	Service Charge Revenue G = A * D *12	Distribution Volumetric Rate Revenue kWh H = B * E	Distribution Volumetric Rate Revenue kW I = C * F	Revenue Requirement from Rates J = G + H + I
Residential	19,530	210,212,474	0	12.25	0.0115	0.0000	2,870,910	2,417,443	0	5,288,353
General Service Less Than 50 kW	1,694	54,285,767	0	26.50	0.0083	0.0000	538,692	450,572	0	989,264
General Service 50 to 999 kW	176	117,338,024	328,299	74.64	0.0000	3.3287	157,640	0	1,092,809	1,250,449
General Service 1,000 to 4,999 kW - Interv	13	108,192,394	293,909	173.31	0.0000	3.0517	27,036	0	896,922	923,958
Unmetered Scattered Load	175	838,540	0	6.50	0.0043	0.0000	13,650	3,606	0	17,256
Sentinel Lighting	175	380,342	810	4.88	0.0000	18.4557	10,248	0	14,949	25,197
Street Lighting	4,474	2,778,881	7,820	2.14	0.0000	28.9538	114,892	0	226,419	341,311
							3,733,068	2,871,621	2,231,099	8,835,788

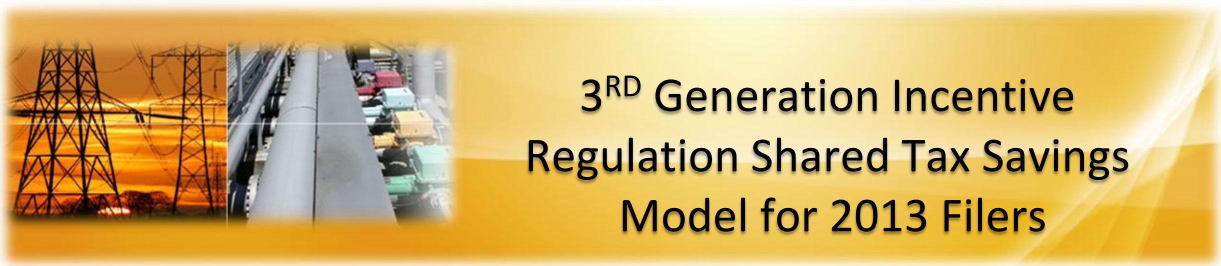
3RD Generation Incentive Regulation Shared Tax Savings Model for 2013 Filers

This worksheet calculates the tax sharing amount.

Step 1: Press the Update Button (this will clear all input cells and reveal your latest cost of service re-basing year).
Step 2: In the green input cells below, please enter the information related to the last Cost of Service Filing.

Summary - Sharing of Tax Change Forecast Amounts

For the 2012 year, enter any Tax Credits from the Cost of Service Tax Calculation (Positive #)	31000	
1. Tax Related Amounts Forecast from Capital Tax Rate Changes	**2012**	**2013**
Taxable Capital		$ -
Deduction from taxable capital up to $15,000,000	$ -	$ -
Net Taxable Capital	$ -	$ -
Rate	0.000%	0.000%
Ontario Capital Tax (Deductible, not grossed-up)	**$ -**	**$ -**
2. Tax Related Amounts Forecast from Income Tax Rate Changes	**2012**	**2013**
Regulatory Taxable Income	$ 306,779	$ 306,779
Corporate Tax Rate	15.50%	15.50%
Tax Impact	$ 16,551	$ 16,551
Grossed-up Tax Amount	**$ 19,587**	**$ 19,587**
Tax Related Amounts Forecast from Capital Tax Rate Changes	$ -	$ -
Tax Related Amounts Forecast from Income Tax Rate Changes	$ 19,587	$ 19,587
Total Tax Related Amounts	**$ 19,587**	**$ 19,587**
Incremental Tax Savings		**$ -**
Sharing of Tax Savings (50%)		**$ -**



This worksheet calculates a tax change volumetric rate rider. No input required. The outputs in column Q and S are to be entered into Sheet 11 "Proposed Rates" of the 2013 IRM Rate Generator Model. Rate description should be entered as "Rate Rider for Tax Change".

Rate Class	Total Revenue $ by Rate Class A	Total Revenue % by Rate Class B = A / $H	Total Z-Factor Tax Change$ by Rate Class C = $I * B	Billed kWh D	Billed kW E	Distribution Volumetric Rate kWh Rate Rider F = C / D	Distribution Volumetric Rate kW Rate Rider G = C / E
Residential	$5,288,353.4510	59.85%	$0	210,212,474	0	$0.0000	
General Service Less Than 50 kW	$989,264	11.20%	$0	54,285,767	0	$0.0000	
General Service 50 to 999 kW	$1,250,449	14.15%	$0	117,338,024	328,299		$0.0000
General Service 1,000 to 4,999 kW - Interval Meter	$923,958	10.46%	$0	108,192,394	293,909		$0.0000
Unmetered Scattered Load	$17,256	0.20%	$0	838,540	0	$0.0000	
Sentinel Lighting	$25,197	0.29%	$0	380,342	810		$0.0000
Street Lighting	$341,311	3.86%	$0	2,778,881	7,820		$0.0000
	$8,835,788	100.00%	$0				
	H		- I				

Appendix E

Interim Tariff of Rates and Charges effective May 1, 2012 (EB-2011-0271)

EB-2011-0271

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Halton Hills Hydro Inc. for an order approving or fixing just and reasonable rates and other charges for the distribution of electricity to be effective May 1, 2012.

BEFORE: Paula Conboy
Presiding Member

Cathy Spoel
Member

INTERIM RATE ORDER
July 4, 2012

Halton Hills Hydro Inc. ("HHH") filed an application with the Ontario Energy Board on June 30, 2011. The Application was filed under section 78 of the *Ontario Energy Board Act, 1998*, S.O 1998, c. 15 (Schedule B), seeking approval for changes to the rates that HHH charges for electricity distribution to be effective May 1, 2012.

On June 14, 2012, the Board issued its Decision and Order (the "Decision") on HHH's application for 2012 distribution rates. The Decision included the approval of proposed Partial Settlement Agreement (the "Partial Agreement") filed on February 28, 2012. The Board approved an effective date of May 1, 2012, and an implementation date of July 1, 2012. HHH filed its draft Rate Order ("DRO") and supporting documentation on June 20, 2012. On June 22, 2012, Energy Probe filed comments on the DRO. Board staff filed comments on June 25, 2012. No other comments were received. HHH filed its response on June 27, 2012.

Deferred PP&E Balance

Due to concerns raised in the proceeding, the Board approved on an interim basis the amount of $836,717 as the appropriate PP&E deferral account balance subject to a confirmation by HHH's auditors (KPMG) and verification of the results by the Board's Regulatory Audit and Accounting.

In the DRO, HHH presented a schedule for amortization of the PP&E balance as a component of its depreciation, an adjustment to its revenue requirement to reflect the return on the unamortized balance, and an adjustment to the return on its rate base. Energy Probe submitted that the two adjustments were not compatible with each other, and in effect cancelled each other out. Board staff agreed with Energy Probe's comment. In its Reply, HHH submitted a revised treatment of the deferred PP&E balance in which the return on rate base is in accordance with the Decision, without the adjustment included in the DRO. HHH also provided a revised cost allocation study that reflects the revisions to the deferred PP&E balance.

The Board approves the revenue requirement submitted in the reply to the comments, subject to any revision to the deferred PP&E balance that may result from the financial audit and review of the PP&E deferral account balance referenced above.

Distribution Rates

Energy Probe noted that the Monthly Service Charges in Appendix A were higher than the corresponding amounts agreed upon in the Partial Agreement for nearly all rate classes, whereas lower charges would have been expected as a result of the Decision. Board staff submitted that the residential rates in the DRO did not yield the proportions of fixed and variable revenue consistent with the Decision. Board staff further noted that the distribution rates in Appendix A, when multiplied by the charge determinants in the approved load forecast, would not be consistent with the base revenue requirement. In its Reply, HHH revised Appendix A to address the comments raised by Energy Probe and Board staff.

The Board approves the revised distribution rates submitted by HHH.

Rate Riders

The DRO did not provide for the treatment of the revenue sufficiency for the two months between the effective date of the 2012 distribution rates and their implementation. On June 27, 2012 HHH submitted its calculation of rate riders that would refund this revenue sufficiency over the remaining ten months of the rate year, that is, from July 1 2012 to April 30, 2013.

HHH's deferral and variance account balances were agreed upon by parties in the Partial Agreement. In the Decision, the Board also approved the disposition of the residual balance in Account 1521 (Special Purpose Charge). The Board approved a disposition period of two years. In its submission, Energy Probe commented that the rate riders in the DRO differed from those in the pre-filed evidence, and that the inclusion of the balance in Account 1521 did not explain the entire difference. Board staff noted that the rate riders in the DRO would dispose of the balances approved in the Decision over a period of 22 months. Board staff did not have an issue with this approach because the sunset date of the rate riders would coincide with the end of HHH's 2013 rate year.

The Board will approve a disposition period of 24 month from the effective date of the Decision and Order for the disposition of deferral and variance account balances. Therefore, the sunset date for the associated rate riders will be April 30, 2014. Similarly, the rate riders for the LRAM and SSM, Smart Meter Balance Disposition and Stranded Meters shall expire on April 30 of the applicable year.

Implementation

The Board has reviewed the information provided in support of the updated DRO, including the additional documentation, and the proposed Tariff of Rates and Charges and is satisfied that the Tariff of Rates and Charges accurately reflects the Board's Decision and Order in this proceeding.

The distribution rates in Appendix A, set out in the Tariff of Rates and Charges are approved on an interim basis, pending completion of the financial audit and review of the PP&E deferral account balance.

On December 21, 2011, the Board issued a Decision with Reasons and Rate Order (EB-2011-0405) establishing the Rural or Remote Electricity Rate Protection ("RRRP") benefit and charge for 2012. The Board amended the RRRP charge to be collected by the Independent Electricity System Operator from the current $0.0013 per kWh to $0.0011 per kWh effective May 1, 2012. The Tariff of Rates and Charges of HHH reflects the new RRRP charge.

THE BOARD ORDERS THAT:

1. The Tariff of Rates and Charges set out in Appendix A of this Rate Order is approved on an interim basis effective May 1, 2012 for electricity consumed or estimated to have been consumed on and after such date.

2. The Tariff of Rates and Charges set out in Appendix A of this Rate Order supersedes all previous Tariff of Rates and Charges approved by the Ontario Energy Board for Halton Hills Hydro Inc.'s service area.

3. Halton Hills Hydro Inc. shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

DATED at Toronto**,** July 4, 2012

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

APPENDIX A

TO RATE ORDER

Halton Hills Hydro Inc

2012 Electricity Distribution Rates

EB-2011-0271

July 4, 2012

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012 (except as noted)
Implementation Date July 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0271

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. The customer will be supplied at one service entrance only. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	12.25
Rate Rider for Recovery of Foregone Revenue – effective July 1, 2012 – April 30, 2013	$	(0.14)
Rate Rider for Recovery of Residual Historical Smart Meter Costs – effective July 1, 2012 – April 30, 2016	$	1.31
Rate Rider for Recovery of Stranded Meter Assets – effective July 1, 2012 – April 30, 2016	$	1.13
Distribution Volumetric Rate	$/kWh	0.0115
Rate Rider for Recovery of Foregone Revenue – effective July 1, 2012 – April 30, 2013	$/kWh	(0.0001)
Low Voltage Service Rate	$/kWh	0.0012
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective July 1, 2012 – April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	0.0012
Rate Rider for Deferral/Variance Account Disposition (2012) – effective July 1, 2012 – April 30, 2014	$/kWh	(0.0018)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM) Recovery – effective July 1, 2012 – April 30, 2014	$/kWh	0.0007
Retail Transmission Rate – Network Service Rate	$/kWh	0.0057
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012 (except as noted)
Implementation Date July 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0271

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	26.50
Rate Rider for Recovery of Foregone Revenue – effective July 1, 2012 – April 30, 2013	$	(0.36)
Rate Rider for Recovery of Residual Historical Smart Meter Costs – effective July 1, 2012 – April 30, 2016	$	1.38
Rate Rider for Recovery of Stranded Meter Assets – effective July 1, 2012 – April 30, 2016	$	1.46
Distribution Volumetric Rate	$/kWh	0.0083
Rate Rider for Recovery of Foregone Revenue – effective July 1, 2012 – April 30, 2013	$/kWh	(0.0001)
Low Voltage Service Rate	$/kWh	0.0011
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective July 1, 2012 – April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2012) – effective July 1, 2012 – April 30, 2014	$/kWh	(0.0018)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM) Recovery – effective July 1, 2012 – April 30, 2014	$/kWh	0.0007
Retail Transmission Rate – Network Service Rate	$/kWh	0.0051
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0042

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012 (except as noted)
Implementation Date July 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0271

GENERAL SERVICE 50 to 999 kW SERVICE CLASSIFICATION

This classification applies to a non-residential customer with an average peak demand equal to or greater than 50 kW over the past twelve months, or is forecast to be equal to or greater than 50 kW, but less than 1,000 kW. For a new customer without prior billing history, the peak demand will be based on 90% of the proposed capacity or installed transformer. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	74.64
Rate Rider for Recovery of Foregone Revenue – effective July 1, 2012 – April 30, 2013	$	(0.31)
Distribution Volumetric Rate	$/kW (or 90%kVA)	3.3287
Rate Rider for Recovery of Foregone Revenue – effective July 1, 2012 – April 30, 2013	$/kW (or 90%kVA)	(0.0130)
Low Voltage Service Rate	$/kW (or 90%kVA	0.4734
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective July 1, 2012 – April 30, 2014 Applicable only for Non-RPP Customers	$/kW (or 90%kVA)	1.5817
Rate Rider for Deferral/Variance Account Disposition (2012) – effective July 1, 2012 – April 30, 2014	$/kW (or 90%kVA)	(0.7063)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM) Recovery – effective July 1, 2012 – April 30, 2014	$/kW (or 90%kVA)	0.0490
Retail Transmission Rate – Network Service Rate	$/kW	2.2257
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW (or 90%kVA)	1.7975

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012 (except as noted)
Implementation Date July 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0271

GENERAL SERVICE 1,000 to 4,999 kW SERVICE CLASSIFICATION

This classification applies to a non-residential customer with an average peak demand equal to or greater than 1,000 kW over the past twelve months, or is forecast to be equal to or greater than 1,000 kW, but less than 5,000 kW. For a new customer without prior billing history, the peak demand will be based on 90% of the installed transformer. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	173.31
Distribution Volumetric Rate	$/kW (or 90%kVA)	3.0517
Rate Rider for Recovery of Foregone Revenue – effective July 1, 2012 – April 30, 2013	$/kW (or 90%kVA)	(0.1108)
Low Voltage Service Rate	$/kW (or 90%kVA	0.4734
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective July 1, 2012 – April 30, 2014		
Applicable only for Non-RPP Customers	$/kW (or 90%kVA)	1.9530
Rate Rider for Deferral/Variance Account Disposition (2012) – effective July 1, 2012 – April 30, 2014	$/kW (or 90%kVA)	(0.7409)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM)		
Recovery – effective July 1, 2012 – April 30, 2014	$/kW (or 90%kVA)	0.0108
Retail Transmission Rate – Network Service Rate	$/kW	2.2257
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW (or 90%kVA)	1.7975

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012 (except as noted)
Implementation Date July 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0271

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, pedestrian X-Walk signals/beacons, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	6.50
Rate Rider for Recovery of Foregone Revenue (per connection) – effective July 1, 2012 – April 30, 2013	$	(1.24)
Distribution Volumetric Rate	$/kWh	0.0043
Rate Rider for Recovery of Foregone Revenue – effective July 1, 2012 – April 30, 2013	$/kWh	(0.0008)
Low Voltage Service Rate	$/kWh	0.0011
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective July 1, 2012 – April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	0.0053
Rate Rider for Deferral/Variance Account Disposition (2012) – effective July 1, 2012 – April 30, 2014	$/kWh	(0.0016)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0051
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0042

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012 (except as noted)
Implementation Date July 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0271

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	4.88
Rate Rider for Recovery of Foregone Revenue (per connection) – effective July 1, 2012 – April 30, 2013	$	0.44
Distribution Volumetric Rate	$/kW	18.4557
Rate Rider for Recovery of Foregone Revenue – effective July 1, 2012 – April 30, 2013	$/kW	1.6698
Low Voltage Service Rate	$/kW	0.3408
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective July 1, 2012 – April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	18.2482
Rate Rider for Deferral/Variance Account Disposition (2012) – effective July 1, 2012 – April 30, 2014	$/kW	(0.7438)
Retail Transmission Rate – Network Service Rate	$/kW	1.5878
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2941

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES
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EB-2011-0271

STREET LIGHTING SERVICE CLASSIFICATION

All services supplied to street lighting equipment owned by or operated for the Municipality, the Region or the Province of Ontario shall be classified as Street Lighting Service. Street Lighting plant, facilities, or equipment owned by the customer are subject to the Electrical Safety Authority (ESA) requirements and Halton Hills Hydro specifications. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	2.14
Rate Rider for Recovery of Foregone Revenue (per connection) – effective July 1, 2012 – April 30, 2013	$	(0.03)
Distribution Volumetric Rate	$/kW	28.9538
Rate Rider for Recovery of Foregone Revenue – effective July 1, 2012 – April 30, 2013	$/kW	(0.4379)
Low Voltage Service Rate	$/kW	0.3338
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective July 1, 2012 – April 30, 2014 Applicable only for Non-RPP Customers	$/kW	0.2586
Rate Rider for Deferral/Variance Account Disposition (2012) – effective July 1, 2012 – April 30, 2014	$/kW	(0.0754)
Retail Transmission Rate – Network Service Rate	$/kW	1.5805
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2676

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012 (except as noted)
Implementation Date July 1, 2012

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EB-2011-0271

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW (or 90%kVA)	(0.50)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES
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EB-2011-0271

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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Customer Administration		
Arrears certificate	$	15.00
Statement of account	$	15.00
Pulling post dated cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Notification charge	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge – no disconnection – after regular hours	$	165.00
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect at meter – after regular hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Service call – customer owned equipment	$	30.00
Service call – after regular hours	$	165.00
Interval Meter Charge	$	20.00
Temporary service install & remove – overhead – no transformer	$	500.00
Temporary service install & remove – underground – no transformer	$	300.00
Temporary service install & remove – overhead – with transformer	$	1000.00
Specific Charge for Access to the Power Poles ($/pole/year)	$	22.35

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012 (except as noted)
Implementation Date July 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0271

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0602
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0496
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

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Appendix F

Board Decision in HHHI's 2008 Cost of Service Application (EB-2007-0696)

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EB-2007-0696

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Halton Hills Hydro Inc. for an order approving or fixing just and reasonable rates and other charges for the distribution of electricity to be effective May 1, 2008.

BEFORE: Gordon Kaiser
Presiding Member

Cynthia Chaplin
Member

DECISION

Background

Halton Hills Hydro Inc. ("Halton Hills") filed an application with the Ontario Energy Board (the "Board"), received on August 15, 2007, under section 78 of the *Ontario Energy Board Act*, *1998*, seeking approval for changes to the rates that Halton Hills charges for electricity distribution, to be effective May 1, 2008.

Halton Hills operates within the municipal boundaries of the Town of Halton Hills and serves approximately 18,000 residential customers and 1,600 general service customers as well as street lighting and sentinel lighting loads.

Halton Hills is one of over 80 electricity distributors in Ontario that are regulated by the Board. In 2006, the Board announced the establishment of a multi-year electricity distribution rate-setting plan for the years 2007-2010. In an effort to assist distributors in preparing their applications, the Board issued the *Filing Requirements for Transmission and Distribution Applications* on November 14, 2006. Chapter 2 of that document outlines the filing requirements for cost of service rate applications, based on a forward test year, by electricity distributors.

On May 4, 2007, as part of the plan, the Board indicated that Halton Hills would be one of the electricity distributors to have its rates rebased in 2008. Accordingly, Halton Hills filed a cost of service application based on 2008 as the forward test year.

Halton Hills requested a revenue requirement of $10,446,283 to be recovered in new rates effective May 1, 2008. The application indicated that the existing rates would produce a revenue deficiency of $1,549,873 for 2008. The resulting requested rate increase was estimated as 18.5% on the distribution component of the bill for a typical residential customer consuming 1,000 kWh per month.

The Board assigned file number EB-2007-0696 to the application and issued a Notice of Application and Hearing dated September 20, 2007. The School Energy Coalition ("Schools") and the Vulnerable Energy Consumers Coalition ("VECC") intervened in this proceeding. The application was dealt with by the Board by way of a written hearing. Board staff and intervenors were permitted two rounds of written interrogatories. Board staff and intervenors filed written submissions on January 18, 2008 and January 23, 2008 respectively. Halton Hills filed reply argument on February 8, 2008.

The full record of the proceeding is available at the Board's offices. The Board has chosen to summarize the record to the extent necessary to provide context to its findings.

Issues

The following issues were raised in the submissions filed by Board staff, Schools and or VECC:

- Load Forecast
- Operating, Maintenance & Administrative Expenses

- Payments in Lieu of Taxes
- Capital Expenditures and Rate Base
- Cost of Capital
- Cost Allocation and Rate Design
- Smart Meter Rate Rider
- Deferral and Variance Accounts
- Shared Savings and Lost Revenue Adjustment Mechanisms
- Rate Impacts

Load Forecast

Halton Hills initially used the 2004 weather normalized values provided by Hydro One for purposes of forecasting customer usage. However, when these values were extrapolated to 2006, the method produced a load that was 8.1% higher than the 2006 actual level. On this basis, Halton Hills rejected its use of weather normalization for load forecasting. Board staff expressed concern with this approach and suggested that weather normalized data could have been used.

Halton Hills instead developed a forecast based on 2006 actual load (and the forecast customer count), which Board staff submitted was unsubstantiated. Schools submitted that the fact that normalized results are greater or lower than actual in a given year is not a sufficient justification for not using weather-normalized consumption to forecast load. Schools submitted that Halton Hills' forecast should be weather normalized and that there was insufficient evidence to support Halton Hills' forecast. VECC questioned the use of one year's weather normalized data for the purposes of generating a forecast, but submitted that there was no better information available.

Halton Hills forecast customer numbers for 2007 and 2008 using a simple trend growth based on data for 2004, 2005 and 2006. Board staff expressed concern that customer numbers changed significantly in some cases from year to year.

Halton Hills
Customer Number Forecast

	2004	2005	2006	2007 forecast	2008 forecast
Residential[1]	17,008	17,684 4.0%	18,203 2.9%	18,337 0.7%	18,902 3.1%
General Service: <50 kW	1,154	1,533 32.8%	1,482 (3.3%)	1,550 4.6%	1,600 3.2%
General Service: 50 kW to 999 kW	153	172 12.4%	178 3.5%	179 0.6%	180 0.6%
General Service: 1000 kW to 4,999 kW	10	10 0%	12 20%	12 0%	12 0%
Un-metered Scattered Load	141	137	136	136	136
Sentinel Lighting	121	177	178	179	179
Street Lighting	3,944	4,144	4,289	4,444	4,450

Notes: 1. includes Residential TOU customers.

Board staff submitted that the forecast rate of total customer growth for 2006 to 2008 is not consistent with the historic period: 4.3% is the historic growth; 2% is the forecast growth. Similarly, while the kWh average load growth from 2004 to 2006 was 6.6%, the forecast is for load growth of 3.2% annual average. Board staff noted that this comparison also includes variations due to weather.

Schools submitted that the load forecast was inconsistent with the capital budget in that projects are identified as being driven by growth in the general service 1000 – 4999 kW class, but no new customers are forecast for that rate class. Schools also agreed with Board staff that the customer growth forecast is not consistent with the historic period, and cited residential and GS>50 classes as two examples.

VECC also submitted that Halton Hills should justify the forecast level of residential customer additions for 2008 and suggested that the residential customer additions should be reduced to the three year historic average and the load, revenue and capital forecasts should be adjusted accordingly.

Halton Hills responded that there was sufficient evidence on the record to support its forecast. It pointed out that if the forecast were weather normalized, the result would be a higher volumetric rate for residential customers and a lower volumetric rate for the GS < 50kW class. Halton Hills did acknowledge a need to develop a methodology for producing weather normalized data, and committed to doing so in time for the next rebasing application.

Board Findings

The evidence shows that the annual growth in customer numbers varied quite substantially between 2004 and 2006, and therefore it is difficult to conclude that there is any particular trend to customer growth, particularly given the limited period examined.

The Board concludes that Halton Hills' forecast of 2008 residential customer numbers is reasonable. The level of growth between 2007 and 2008 is approximately the average of the growth experienced between 2004 and 2006. The Board finds that the number of customers in the GS 50-999 kW rate class for 2008 will be raised from 180 to 185. This class experienced high growth in 2005 and more moderate growth in 2006, although virtually no growth is forecast for 2007. The Board concludes that a level of 185 for 2008, which is 3.5% higher than the 2007 forecast, better reflects the historical experience but still incorporates the low growth expected in 2007. The Board will raise the GS < 50 kW 2008 forecast to 1,621 customers. This level represents a continuation of the level of growth forecast for 2007. The Board will make no further adjustments to the customer number forecast.

In the Board's view, the alternative forecast proposed by Halton Hills is fundamentally flawed in that it is not weather normalized, which Halton Hills implicitly acknowledges through its stated intention to develop its own weather normalization methodology for the next rebasing application.

The Board finds that Halton Hills should base its rates on a weather normalized forecast. The Board concludes that the most appropriate approach is to use the historical average of the weather normalized average use for the residential and GS < 50 kW rate classes over the period 2002 through 2006. For residential customers, that average weather normalized use is 11,111kWh/customer; for the GS < 50 kW class, the average weather normalized use is 39,946 kWh/customer. (This latter consumption level will be applied to the revised higher customer number forecast of 1,621.)

For the GS 50 – 999 kW class, the forecast consumption per customer contained in the evidence (700,730 kWh[1]) will be applied to the revised higher customer number forecast of 185.

The load forecasts for the other rate classes will remain unchanged.

Operating, Maintenance & Administration ("OM&A") Expenses

The test year total controllable OM&A expenses (Operations, Maintenance, Billing & Collection and Administration & General Expenses) forecast is $5.319 million, an increase of 16% from 2006 actual spending. Actual controllable OM&A expense in 2006 was 14.4% higher than the Board approved level. A further 3.8% increase is forecast for 2007. The forecast increase from 2007 to 2008 is 11.8%.

Board staff submitted that the 11.7% increase in labour costs between 2007 and 2008 is mainly due to annual salary increases of 3%, three staff additions, financing for an MBA program and staff development and training.

Schools submitted that the increases in total compensation appear to be excessive; in Schools estimation, the average annual increase is 6% since 2004 – not including the impact of the additional three staff – and that most of the increase appears in the difference between 2006 Board Approved and 2006 actual. Schools took the position that the increases were not well substantiated and submitted that a number of adjustments should be made for a total reduction of $286,746. With these adjustments, the OM&A budget of $5,032,254 would still represent a 5.7% increase over 2007 and a 9.8% increase over 2006 actual.

[1] Total forecast consumption for the class is 126,131,349 kWh. This consumption divided by the forecast customer number of 180 results in an average customer forecast of 700,730 kWh.

VECC also expressed concern about the increases in controllable expenses between 2006 and 2008 and noted that the increase in total compensation is one of the main drivers. VECC suggested that the Board require Halton Hills to benchmark its total compensation and OM&A cost on per customer and per kWh distributed from 2000 to 2008 and to file this information with its next rate application. VECC submitted that OM&A expense should be reduced by $56,000 which is 10% of the claimed increase over 2007 and approximates the level of unexplained difference in year over year cost changes between 2006 and 2008.

VECC also expressed concern with the senior management incentive plan. VECC submitted that the Board should require time dockets or time estimates to support the allocation of time and cost between Halton Hills and its affiliates for the President, Vice President and CFO.

Halton Hills responded that the 11.7% increase from 2007 to 2008 was due to two main factors: the addition of three staff positions and compensation increases arising from staff movement through salary grids and the implementation of management incentives in the areas of safety and financial performance. Halton Hills submitted that non-utility incentive payments had no rate impact because they are handled through inter-company charges. Halton Hills submitted that when total compensation (including capitalized compensation) is compared year over year, the increase between 2006 actual and 2008 is 11.8% or an average of 5.9% per year.

Board Findings

The Board does not find that the average increase in total compensation of 5.9% per year between 2006 and 2008 is excessive given the evidence regarding the staff additions and compensation increases. The Board is satisfied with the explanations Halton Hills has advanced for these increases. The Board will make no adjustment for the non-utility portion of the management incentive payments as Halton Hills has submitted that these charges are removed for purposes of determining the revenue requirement. However, the Board finds that the evidence for this adjustment should be more clearly presented in future applications.

In response to VECC's submission regarding benchmarking, the Board notes that cost comparisons are being discussed in the context of the next generation of incentive ratemaking for electricity distributors.

Shared Services Costs

VECC submitted that the details of Halton Hills affiliate pricing should be filed in reply submission or later as a letter to the Board's Compliance Office. VECC submitted that the Affiliate Relationships Code ("ARC") requires that the transfer price for internally provided services to be fully allocated costs of the service provider, including a return on the capital employed at the approved weighted average cost of capital.

Board Findings

The ARC requires the use of fully allocated costs for the pricing of shared corporate services. Services provided by the utility to an affiliate must be at no less than market price. The Board is satisfied that the information provided by Halton Hills substantiates its claim that these services are being provided at market prices.

Payments in lieu of Taxes ("PILs")

Halton Hills forecast its PILs using a combined Ontario and federal income tax rate of 34.5% for 2008.

Board staff questioned whether Halton Hills' PILs allowance should be recalculated to reflect the elimination of interest expense additions and deductions, adjustments to depreciation and CCA that might result from a change in rate base, and a new combined tax rate of 33.5%. Board staff noted that Halton Hills had agreed that its treatment of interest expense was not in accordance with prior Board guidance.

Schools submitted that Halton Hills' PILs calculation should be adjusted to take account of changes in federal corporate income tax rate, the provincial capital tax, and the federal capital cost allowance rates. Schools also opposed Halton Hills' proposed treatment of interest expense. In Schools' view, Halton Hills has credited ratepayers with the deemed interest expense rather than its actual expense, which appears to be due to the difference between the actual capital structure and the deemed capital structure. Schools submitted that the proposed adjustment to interest expense should be denied because allowing the company to enjoy the tax advantage of having higher than deemed debt would "provide too great an incentive to utilities to have actual debt components in excess of that determined by the Board to be an appropriate capital structure."

Halton Hills responded that it would make the adjustment to interest expense and recalculate PILs using the most recent tax legislation.

Board Findings

The Board finds Halton Hills' proposal with respect to interest expense and the determination of PILs using the most recent tax legislation to be appropriate.
In calculating the PILs provision, the Board directs Halton Hills to reflect in its Draft Rate Order the new federal income tax rate (reduced to 19.5%, yielding a combined federal and Ontario income tax rate for 2008 of 33.5%), the change in the Ontario capital tax exemption amount to $15 million from $12.5 million, and the new CCA class rates applicable.

Capital Expenditures and Rate Base

The following table summarizes Halton Hills' rate base and capital expenditures for 2006, 2007 and 2008:

Halton Hills
Rate Base, Capital Expenditures & Construction Work in Progress

$ thousands	**2006**	**2007**	**2008**
Rate Base	32,208	34,723	37,954
Capital Budget	3,276.5	4,641.7	5,131
Construction Work in Progress	796.5	200	700
Total Capital Expenditures	4,074	4,842	5,831

Board staff identified the following cost drivers for the 47% increase in the 2008 capital budget compared to the 2006 budget:

- Customer additions and load growth
- New transformer station
- Load transfer eliminations.

Board staff expressed some concerns regarding expenditures related to load transfer eliminations and invited Halton Hills to address a number of specific issues regarding the costs and timing of projects. Schools took the position that the capital budget was generally well supported by the evidence.

VECC noted that the capital additions for 2008 were above historical levels and expressed concern that there did not appear to be a comprehensive asset management plan and that while Halton Hills had provided information on most projects, there was minimal information on the capital costs for Property Purchases. Halton Hills replied that the three land purchases were all for municipal substations and were therefore expected to cost the same, namely $100,000.

In reply, Halton Hills referred to evidence to the effect that the "Winston Churchill Blvd. – Steeles to Norval Metering Point" project was primarily a road widening project, not a load transfer elimination project, although load transfers were included in the design of the project as an additional efficiency. Further, Halton Hills removed the expenditures related to load transfers because "the cost of assets that will be transferred between utilities will not be known until all assets comprising the load transfers are verified and a monetary assessment is conducted."

Board Findings

The Board finds that Halton Hills has substantiated the proposed test year capital expenditures based on system needs and asset assessment. The budget is accepted for purposes of determining rates or 2008.

The Board notes that Halton Hills does not yet know the asset values involved in the remaining load transfer projects and that therefore no amounts related this have been included in rate base for 2008.

Service Reliability Indices

Service reliability indices measure the performance of the system from the customer perspective. SAIDI and SAIFI measure the duration and frequency of customer interruptions; CAIDI represents the average duration of an interruption.

Halton Hills did not provide reliability performance data for 2007. Although performance in 2006 was better than in 2003 and 2005, for SAIDI and SAIFI, performance in 2004 was better than in 2006. The statistics are set out in the following table:

Halton Hills
Service Reliability Indices

	2003	2004	2005	2006	2007 forecast	2008 forecast
SAIDI	3.4253	1.1234	1.8462	1.193	1.2	1.2
SAIFI	1.8774	1.2190	1.7034	1.534	1.6	1.6
CAIDI	1.8200	0.9200	1.0838	0.780	0.8	0.8

Board staff submitted that the evidence was unclear regarding performance for 2007 and that there did not appear to be a target for 2008. In the absence of this information, Board staff submitted that it was not possible to evaluate how Halton Hills would sustain or enhance its reliability. VECC made similar submissions. Halton Hills replied that its forecast of reliability for 2007 and 2008 is relatively stable and that a number of its capital projects are designed to maintain or enhance reliability.

Board Findings

Halton Hills' forecast of reliability remains within historical levels of performance. In addition, Halton Hills has identified a number of capital projects which will maintain or enhance reliability. The Board is satisfied with this approach.

The Board is undertaking a separate consultation on Electricity Service Quality Regulation which will look at these issues on an industry-wide basis. The Board concludes that no adjustment to the capital budget is required.

Assessment of Asset Condition and Asset Management Plan

Halton Hills did not file a formal asset management plan. It did provide information regarding internal assessments which had been conducted.

Board staff submitted that without an asset management plan, it is not clear how Halton Hills prioritizes its work on a short and long term basis in order to maintain its assets. Board staff questioned whether an independent assessment of asset condition should be done and whether a formal asset management plan should be developed. Schools agreed that an asset plan was necessary to have a more transparent understanding of Halton Hills plans, but Schools was not convinced that the expense of an independent assessment of the asset condition was warranted and noted that the IRC Building Sciences Group report was commissioned by Halton Hills after identifying the problem internally. Schools concluded that this type of approach was appropriate for a utility the size of Halton Hills. Halton Hills agreed with Schools that this was the appropriate approach for a utility of its size.

Board Findings

The Board finds that Halton Hills' approach to project prioritization and asset management is sufficient for purposes of substantiating the 2008 capital budget.

Working Capital

VECC submitted that the 15% for purchased power is too high and should be 12% based on the Toronto Hydro and Hydro One lead lag studies and that working capital should be further reduced to reflect the decrease in transmission charges to be in effect for 2008.

Board Findings

The Board finds that there is insufficient evidence to apply the results of other lead lag studies to Halton Hills' determination of working capital.

The Board concludes that the most accurate data should be used in the calculation of working capital. For this reason, Halton Hills is directed to recalculate working capital using the new lower transmission rates, including Hydro One's proposed rates. (This adjustment is further described below in the section Retail Transmission Rates.) The Board also directs Halton Hills to update the cost of power to reflect the November 1, 2007 RPP rate representing the all in supply cost of $0.054/kWh.

Conclusion

The Board accepts the capital budget forecast and rate base forecast for purposes of determining rates.

Cost of Capital

The Board has established a methodology for the determination of the cost of capital. This methodology is set out in the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, dated December 20, 2006. The Board's Report sets out the formulas to be used to determine the return on equity and the deemed costs of long term and short term debt and sets out the process by which these figures will be updated.

Halton Hills provided indicative amounts, but proposed that the rates be adjusted in the Decision to reflect updated amounts, in accordance with the Board's methodology. Halton Hills indicated that its cost of long-term debt is the weighted average of 5.78% for new third-party debt and 6.25% for municipally held long-term debt. VECC submitted that the cost rate for the third party long-term debt might not be firm at 5.78% and suggested that Halton Hills confirm the exact nature of the cost.

Board Findings

The Board finds that the evidence is sufficient to substantiate the cost of 5.78% for new long-term debt. The Board also approves the capital structure as proposed.

The Board finds that the cost of capital will be set in accordance with the cost of capital methodology in the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*. The cost of long term debt will be the weighted average of the affiliate debt at the new deemed rate of 6.1% and the new third party debt at 5.78%, for a total cost of 6.00%. The final approved levels are set out in the table below.

Halton Hills
Board-approved 2008 Capital Structure and Cost of Capital

Capital Component	% of Total Capital Structure	Cost Rate (%)
Short-Term Debt	4.00%	4.47%
Long-Term Debt	49.30%	6.00%
Equity	46.70%	8.57%
Preference Shares	--	
Total	**100%**	**7.14%**

Cost Allocation and Rate Design

The following issues are dealt with in this section:

- Revenue to Cost Ratios
- Line Losses
- Charges to Hydro One
- Retail Transmission Service Rates
- Monthly Charges
- Residential Time of Use Class
- Smart Meter Rate Rider
- Rate Impacts

Revenue to Cost Ratios

Revenue to Cost ratios measure the relationship between the revenues expected from a class of customers and the level of costs allocated to that class. The Board has established, as a matter of policy, target revenue to cost ratios for Ontario electricity distributors in its report *Application of Cost Allocation for Electricity Distributors,* dated November 28, 2007. The following table sets out Halton Hills' revenue to cost ratios from its Informational filing and its proposed ratios for 2008 (based on interrogatory responses):

Halton Hills
Revenue to Cost Ratios

Customer Class	Informational Filing Run 2	Proposed Ratios Contained in Interrogatory Responses	Board Target Ranges
Residential	88.34	94.60	85 – 115
GS < 50 kW	81.75	94.44	80 – 120
GS 50 – 999 kW	156.93	134.81	80 – 180
GS 1000 – 4999	164.17	131.92	80 – 180
Street Lights	15.14	24.27	70 – 120
Sentinel Lights	36.74	53.43	70 – 120
USL	106.77	103.37	80 -- 120

The proposed ratios are within the ranges set by Board policy, with the exception of Street Lights and Sentinel Lights, which both remain substantially below the Board's minimum target level of 70%.

Schools submitted that although the ratios for the GS>50 and GS 1000 – 4999 rate classes are within the Board range, they are still too high, while the Street Lighting is still below the minimum. In Schools' view, there is no justification for a Street Lighting ratio less than 100%, especially given that the Street Lighting ratepayer is a Halton Hills affiliate.

VECC submitted that the ratios had not been correctly determined and offered alternative ratios. VECC submitted that the ratio for the Street Lighting and Sentinel Lighting classes should be increased but that the ratio for the GS>50 kW should be decreased further.

Halton Hills replied that it was committed to continuing to move to 100% in future rate applications, but took the position that to move the Street Lighting and Sentinel Lighting classes to the level of the Board guidelines would result in rate shock for these customers.

Board Findings

The Board finds that Halton Hills should adjust the rates for Street Lights so that the ratio moves to 33%, which is about one third of the way between the historical level and the target minimum of 70%. While this represents a large increase for this class in percentage terms, the Board finds that the increase in absolute terms (which is approximately $63,000 in additional revenue) is acceptable and necessary in order to make significant progress toward bringing the class into the appropriate range. The Board directs that the additional revenue from this adjustment be applied to further reduce the over-recovery from the GS classes.

The Board finds that the proposed ratio for Sentinel Lights is acceptable, as it represents movement about half way to the target minimum of 70%.

The Board notes Halton Hills' stated commitment to move the ratios to 100%. The Board therefore directs Halton Hills to file a proposal as part of its 2009 IRM application for how all classes will be moved to revenue to cost ratios of 100% within the term of the IRM plan.

Line Losses

Halton Hills requested a total loss factor of 4.99% for the test year. Halton Hills' approved total loss factor from 2006 was 1.0368.

The table below sets out the historical and forecast distribution loss factors.

Halton Hills
Distribution Loss Factors

	Actual				
	2002	**2003**	**2004**	**2005**	**2006**
Distribution Loss Factor	1.0207	1.0365	1.0509	1.0637	1.0357

Halton Hills stated that the 2006 distribution loss factor was incorrect, and that the historic figures were lower than actual because of less accurate data gathering and an increase in un-metered power. Board staff noted the inconsistency in the reporting of 2006 results and the increase from 2004 to 2005. Board staff questioned whether there was a need to reduce the distribution loss factor.

Schools submitted that Halton Hills has not provided sufficient evidence to demonstrate why past line loss estimates were incorrect or that the un-metered power issue will significantly increase Halton Hills' distribution line losses. In addition, the proposed level would be quite high. VECC agreed with Board staff that there should be further explanation for why the 2008 loss factor should not be set at the historic level. In the alternative, if there is not an estimation problem, then VECC expressed concern with the high level of losses and the lack of evidence that Halton Hills is taking appropriate actions to reduce losses.

Halton Hills agreed that the distribution loss factor is high and indicated that it has initiated a process to review the loss factor. Halton Hills proposed that the Board approve the level for one year and require Halton Hills to report in writing on the results of the process underway and propose any necessary modification to the loss factor for implementation in May 2009.

Board Findings

The Board will accept the proposed total loss factor of 4.99% for 2008. However, the Board is concerned that Halton Hills is forecasting such a high level of distribution loss factors and will accept the company's proposal to report on its review process so that any necessary modifications may be made to the 2009 rates.

The Board notes that two activities are identified its *2007-2010 Business Plan* related to line losses: audit reviews on utility performance improvement in line losses and a study of potential incentives associated with line loss reductions.

The Board has recently completed the information gathering phase of the first activity and a summary report will be released shortly which will help inform policy development in this area.

Charges to Hydro One

Although Halton Hills is a host distributor for Hydro One Distribution, it did not apply for a Wheeling rate. Instead, Halton Hills made changes to its distribution system so as to treat Hydro One Distribution as a customer in the GS 1000-4999 kW class.

Board staff submitted that there was no evidence as to what changes were made to the system related to this proposal. Board staff also submitted that a distributor does not have the authority to change the status of an embedded distributor to that of a load customer, and that Halton Hills should have shown an embedded class in its Informational Cost Allocation study.

Halton Hills responded that it changed Hydro One from an embedded distributor to a commercial retail customer at the request of Hydro One and that a metering change was made after which Halton Hills took ownership of the metering unit.

Board Findings

The Board is satisfied with Halton Hills' explanation and finds that the arrangement with Hydro One is acceptable for current purposes. The Board notes that this issue has arisen in the context of the Board's work on the design of distribution rates. The Board expects Halton Hills to keep itself informed as to potential developments through that process. The Board also expects Halton Hills to reflect this change in its future cost allocation filings.

Retail Transmission Service Rates

In response to interrogatories, Halton Hills proposed to adjust its retail transmission rates, but by less than the change in wholesale transmission charges. Halton Hills noted that new charges have not been approved for Hydro One Distribution, and Halton Hills takes delivery from Hydro One at five delivery points.

Board staff pointed out that the new wholesale transmission rates apply to two of Halton Hills' delivery points. Board staff submitted that the new retail transmission rates do not appear to have been calculated correctly.

Halton Hills responded that it receives much of its power through embedded delivery points and that the rate adjustments proposed by Hydro One Distribution are smaller in percentage terms than the corresponding decreases approved for wholesale transmission rates. Halton Hills reported that Hydro One has indicated that proposed rates for retail network transmission service and retail line connection and transformation service will be $2.02/kW and $1.90/kW respectively. Halton Hills responded that its proposed retail transmission rates take account of three factors: the recent change in wholesale transmission rates; the expected change in retail transmission rates for Hydro One's embedded distributors; Halton Hills' current rates are over-collecting.

Board Findings

The Board finds Halton Hills' approach to be acceptable.

Monthly Charges

Board staff noted that the proposed increases in the monthly charges for the GS < 50 kW and Un-metered Scattered Load classes are lower than the increases in the volumetric rates and that the resulting charges are above the 2006 levels, which in turn are above the upper range of the Information Cost Allocation Filing.

Schools supported the changes in the fixed charges for the GS<50 and GS>50 rate classes. VECC submitted that the appropriate way to determine the fixed/variable split is to calculate the total 2008 revenue for each customer class using 2008 billing quantities and 2007 rates, excluding the smart meter and LV rate adders. Halton Hills responded that proposed monthly charges are the direct result of cost allocation strategies and maintained that the charges are fair and equitable.

Board Findings

The Board finds Halton Hills' approach to the setting of monthly charges to be acceptable.

Residential Time of Use Class

Halton Hills proposed to retain its residential time of use class for 2008, with two customers. The rates would be lower than the current rates for the class and lower than the regular residential rates. The rates for these two classes were the same until 2005.

In 2006 different rates were set, although identical rates had been part of the application. The necessary manual adjustment was not made, and these separate rates continued as part of the IRM formula approach. Board staff submitted that there is no evidence as to whether the proposed rate is cost-based, because the class does not appear as a separate entity in the Information Cost Allocation filing.

Halton Hills replied that this rate class should have the same distribution rates as the residential class and indicated that it was prepared to make this adjustment.

Board Findings

The Board finds Halton Hills' proposal that both these classes have the same rates is acceptable.

Smart Meter Rate Rider

Halton Hills currently has a smart meter rate adder of $0.28 per metered customer per month. Halton Hills proposed a rate adder of $1.18 per metered customer/month and cited its Smart Meter Investment Plan, which had originally been filed with the Board in December 2006.

Board staff pointed out that Halton Hills originally proposed a rate adder of $1.18 in its 2007 EDR application and that the Board denied that request on the basis that Halton Hills was not named by Regulation 153/07 as being authorized to undertake smart meter activity. Schools and VECC both submitted that the proposed rate adder should be rejected. Halton Hills responded that it is not requesting a rate rider of $1.18 until it can submit a more comprehensive plan based on clarification of the Ministry of Energy's intentions but that it is requesting a continuation of the current rate rider.

Board Findings

The smart meter rate adder will remain unchanged at $0.28 per metered customer/month. Halton Hills is not authorized to undertake smart meter activity at this time. If Halton Hills receives authorization to undertake smart meter activity, then it may consider applying for a new smart meter rate adder.

Rate Impacts

VECC noted that 43% of Halton Hills' residential customers are below the 750 kWhs per month consumption level and submitted that the proposed volumetric distribution rate increases for these customers were unacceptably high – at almost 24%.

Board Findings

The Board finds the level of proposed increase is not so high that rate impact mitigation measures are required. While acknowledging that the volumetric rate rider was changed from a charge to a refund, the pre-filed evidence indicates increases for residential customers on a total bill basis are 7.4% for customers consuming 100 kWh per month and 2.9% for customers consuming 500 kWh per month. The Board would also note that the residential class still maintains a revenue to cost ratio of less than 100%.

Deferral and Variance Accounts

Halton Hills proposed to dispose of the following deferral and variance account balances as at April 30, 2008:

Account Number	Account Name	Balance
1508	Other Regulatory Assets	$241,783
1518	RCVA – Retail	$12,228
1525	Miscellaneous Deferred Debits	$59,814
1548	RCVA – STR	($3,102)
1550	LV Variance	$21,164
1562	Deferred Payments in Lieu of Taxes	($115,260)
1570	Qualifying Transition Costs	($2,038)
1571	Pre-market Opening Energy Variances	($20,603)
1580	RSVA – Wholesale Market Service Charge	$251,077
1582	RSVA – One-Time WMS	$54,703
1584	RSVA – Retail Transmission Network Charges	$19,766
1586	RSVA – Retail Transmission Connection	($579,951)

	Charges	
1588	RSVA – Power	$1,654,427[2]
1590	Recovery of Regulatory Asset Balances	$130,533[2]
	Total	$1,724,601

Halton Hills proposed to recover these amounts over three years using a rate rider.

Accounts 1518, 1548, 1580, 1582, 1584, 1586, 1588

Account 1588 (RSVA Power) is part of the Board's ongoing "Bill 23" process. The Board has recently announced (by letter dated February 19, 2008) that it intends to launch an initiative for the review and disposition of Account 1588 and that it will consider the use of "disposition triggers". The Board also indicated it will consider whether to extend this initiative to all of the RSVA and RCVA accounts.

The Board finds that it would be more appropriate to await developments in that process than to dispose of these accounts at this time.

Account 1590 (Recovery of Regulatory Asset Balances)

Halton Hills proposed to dispose of Account 1590 before the final balance has been determined. Board staff questioned whether this was a proper "true-up" as envisaged by the Board in its Phase 2 Decision in the Review and Recovery of Regulatory Assets[3]. Halton Hills is forecasting a residual balance of $130,533 and submitted in its reply argument that it is appropriate to forecast the principal balance.

Board Findings

The Board finds that it is not appropriate to forecast the principal balance in this account or to dispose of this account at this time. The current rate riders for regulatory assets were designed to recover the approved amounts over two years. Those rate riders expire on April 30, 2008, after which Halton Hills will be able to accurately determine the residual balance.

[2] Includes forecasted principal balance beyond December 31, 2006

[3] RP-2004-0117, RP-2004-0118, RP-2004-0100, RP-2004-0069, RP-2004-0064 December 9, 2004 *Decision With Reasons, Recovery of Regulatory Assets - Phase 2*, Section 9.019

Account 1508

Halton Hills reported that it was using an interest rate of 3.88% for both sub-accounts in Account 1508, OEB Cost Assessments and OMERS Pension Contributions for the period January 1, 2005 to April 30, 2006. However, the Board's letter of December 20, 2004, established 5.75% as the interest rate for the OEB Cost Assessments for the period January 1, 2005 through April 30, 2006. Board staff pointed out that the difference would be immaterial.

Board Findings

Halton Hills has been applying the correct interest rate since May 1, 2006. The Board will not require any further adjustment to this account. This account shall be disposed of as proposed.

Account 1570 (Qualifying Transition Costs) and Account 1571 (Pre-Market Opening Energy Variances)

Halton Hills is proposing to dispose of these two accounts with a refund to customers. Board staff pointed out that these accounts were given final disposition and closed in the 2006 EDR Decision. Halton Hills explained that in the case of account 1570, approved recoveries exceeded actual which resulted in a "small non-material credit balance". For account 1571, a credit balance exists due to "back-billings" to customers in 2006 to the pre-market opening period for charges that were neither billed nor accrued to the pre-market opening period.

Board Findings

It appears that Halton Hills discovered that the amounts applied for in the 2006 EDR were overstated for these two reasons, and is attempting to refund the balance to customers. Given the circumstances, namely that the amounts are not large, that the result is a refund to customers and that Halton Hills has initiated the adjustment, the Board will allow for the balances in these two accounts to be rolled into account 1590 to be cleared along with the true up of the residual balance of this account, and not refunded to ratepayers via a rate-rider at this time.

Account 1562

The Board will not dispose of this account as part of this proceeding. The Board, by letter dated March 3, 2008, has announced that it will initiate a combined proceeding to determine the methodology that should be used for the calculation and disposition of account 1562.

Conclusion

The Board finds that accounts 1508, 1525, 1550, 1570, and 1571 should be disposed in accordance with Halton Hills' proposals, with the adjustments set out above.

Shared Savings Mechanism ("SSM") and Lost Revenue Adjustment Mechanism ("LRAM")

Halton Hills requested approval for an LRAM amount of $8,721 and an SSM amount of $33,583. Halton Hills proposed that the LRAM and SSM rate riders be combined into, and recovered through, a single distribution rate rider and requested a one year recovery period.

Board staff, Schools and VECC filed supplementary Interrogatories in relation to Halton Hills' LRAM and SSM claim. The supplementary Interrogatories mainly focused on the filing requirements set out in the Board's November 14, 2006 *Filing Requirements for Transmission and Distribution Applications,* and consistency with the Board's Decision (EB-2007-0096) regarding Toronto Hydro-Electric System Limited's LRAM and SSM claim for 2005 and 2006.

Halton Hills, as a result of the supplementary Interrogatories and the EB-2007-0096 Decision, has recalculated the LRAM and SSM amounts. The LRAM amount has been revised to $7,981 and the SSM amount to $21,454.

Board Findings

The Board finds that Halton Hills has satisfied the Board's filing requirements and that its claim for LRAM and SSM is consistent with the Board's Toronto Hydro decision. The Board approves an LRAM amount of $7,981 and an SSM Amount of $21,454. The amounts will be cleared through a rate rider over one year as proposed by Halton Hills.

Implementation

The Board has made findings in this Decision which change the revenue deficiency and change the deferral and variance account balances for disposition, and therefore the proposed 2008 distribution rates. These are to be properly reflected in a Draft Rate Order incorporating an effective date of May 1, 2008 for the new rates.
In filing its Draft Rate Order, it is the Board's expectation that Halton Hills will not use a calculation of a revised revenue deficiency to reconcile the new distribution rates with the Board's findings in this Decision. Rather, the Board expects Halton Hills to file detailed supporting material, including all relevant calculations showing the impact of this Decision on Halton Hills' proposed revenue requirement, the allocation of the approved revenue requirement to the classes and the determination of the final rates. Halton Hills should also show detailed calculations of the revised retail transmission rates and variance account rate riders reflecting this Decision

A Rate Order and a separate cost awards decision will be issued after the processes set out below are completed.

The Board Therefore Orders That:

1. Halton Hills Hydro Inc. shall file with the Board, and shall also forward to VECC and SEC, a Draft Rate Order attaching a proposed Tariff of Rates and Charges reflecting the Board's findings in this Decision, within 14 days of the date of this Decision. The Draft Rate Order shall also include customer rate impacts and detailed supporting information showing the calculation of the final rates.

2. VECC and SEC shall file any comments on the Draft Rate Order with the Board and forward to Halton Hills Hydro Inc. within 20 days of the date of this Decision.

3. VECC and SEC shall file with the Board and forward to Halton Hills Hydro Inc. their respective cost claims within 26 days from the date of this Decision.

4. Halton Hills Hydro Inc. may file with the Board and forward to VECC and SEC responses to any comments on its Draft Rate Order within 26 days of the date of this Decision.

5. Halton Hills Hydro Inc. may file with the Board and forward to VECC and SEC any objections to the claimed costs within 40 days from the date of this Decision.

6. VECC and SEC may file with the Board and forward to Halton Hills Hydro Inc. any responses to any objections for cost claims within 47 days of the date of this Decision.

7. Halton Hills Hydro Inc. shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

DATED at Toronto, March 27 2008
ONTARIO ENERGY BOARD

Original signed by

____
Gordon Kaiser
Presiding Member

Original signed by

____
Cynthia Chaplin
Member

Appendix G

Board Staff Interrogatories and HHHI Responses in HHHI's 2012 Cost of Service Application (EB-2011-0271)

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Responses to Letters of Comment

1.

Following publication of the Notice of Application, did HHHI receive any letters of comment? If so, please confirm whether a reply was sent to the author of the letter. If confirmed, please file that reply with the Board. If not confirmed, please explain why a response was not sent and confirm if HHHI intends to respond.

Rate Base Assets

2.

Reference: Exhibit 2 / 3 / 4 / p. 1

International Accounting Standard ("IAS") 16 'Property, Plant and Equipment' states that the cost of PP&E comprises any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.

IAS 23 states that directly attributable borrowing costs are capitalized on qualifying assets only. It also indicated that a qualifying asset is an asset that necessarily takes a substantial period of time to get ready for its intended use or sale.

HHHI stated at the referenced page:

> *HHHI does not capitalize interest on funds used during construction as capital projects are budgeted for and completed in the fiscal year. HHHI capitalizes, through internal cost allocations, any indirect administrative support costs such as Finance, Human Resources or Corporate Services.*

a) Please explain why HHHI capitalizes indirect administrative support costs such as Finance, Human Resources or Corporate Services when IAS 16 states that only "directly attributable" costs can be capitalized. Please identify if and when HHHI will change its policy and practices of capitalizing the indirect administration support costs. If not, why not.

b) It appears that HHHI does not capitalize interest on funds used during construction as capital projects are budgeted for and completed for a period of less than one year. Please confirm.

c) If answer to part "b" is yes, does HHHI concur that IAS 23 requires that directly attributable borrowing costs are capitalized upon qualifying assets that may take a substantial period of time to get ready for its intended use or sale? If so, does HHHI plan to change its capitalization policy for the attributable borrowing costs? If not, why not?

3.
References: Exhibit 2 / 3 / 4 / p. 1; Report of the Board *'Transition to International Financial Reporting Standards'* ("IFRS"), July 28, 2009 [EB-2008-0408]

The Board Report said at p. 15:

> *The utility will file a copy of its capitalization policy, identifying any updates to the policy, as part of its first rate filing after IFRS adoption. Revenue requirement impacts of any change in capitalization policy must be specifically and separately quantified.*

HHHI proposed that its test year be based on the Modified International Financial Reporting Standards ("MIFRS").

a) Please provide a copy of the capitalization policy from the adoption of MIFRS.

b) Please detail all changes to accounting policies arising from the adoption of MIFRS.

c) Please state the impact on the revenue requirement of the changes due to:

    i. Changes to the accounting policies due to MIFRS to each major component of the revenue requirement (e.g. rate base, operating costs, etc), including the overall dollar impact on the proposed revenue requirement,

    ii. Changes to the capitalization policies due to MIFRS to each major component of the revenue requirement (e.g. rate base, operating costs, etc), including the overall dollar impact on the proposed revenue requirement, and

    iii. Other changes to the capitalization since 2008 that are not related to MIFRS to each major component of the revenue requirement (e.g. rate base, operating costs, etc), including the overall dollar impact on the proposed revenue requirement.

4.
References: Report of the Board *'Transition to International Financial Reporting Standards* ("IFRS"), July 28, 2009 [EB-2008-0408]; Exhibit 2 / 3 / 4 / p.1

The Board Report has stated at p. 15:

> *The Board will require utilities to adhere to IFRS capitalization accounting requirements for rate making and regulatory reporting purposes after the date of adoption of IFRS.*

IAS 16 Property, Plant and Equipment states that the cost of PP&E comprises of any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.

IAS 23 states that directly attributable borrowing costs are capitalized upon qualifying assets only. It also indicated that a qualifying asset is an asset that necessarily takes a substantial period of time to get ready for its intended use or sale.

The Board Report also stated at p. 40:

> *The Board will continue to publish interest rates for CWIP as it does now. Where incurred debt is acquired on an arms length basis, the actual borrowing cost should be used for determining the amount of carrying charges to be capitalized to CWIP for rate making during the period, in accordance with IFRS. Where incurred debt is not acquired on an arm's length basis, the actual borrowing cost may be used for rate making, provided that the interest rate is no greater than the Board's published rates. Otherwise, the distributor should use the Board's published rates.*

HHHI stated in its Capitalization Policy (Exhibit 2 / 3 / 4):

> *HHHI does not capitalize interest on funds used during construction as capital projects are budgeted for and completed in the fiscal year.*

With respect to the impact of MIFRS on capital expenditures:

a) Please confirm if the costs capitalized are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. If not, please explain.

b) Has HHHI consulted with its external auditors or professional advisors regarding the change in capitalization of overhead within IFRS requirements? If yes, please provide supporting documentation. If not, please identify if there is any plan in the near future for such a consultation.

c) Please identify the burden rates related to the capitalization of costs of self-constructed assets:
    i. Prior to transition (from the last rebasing application to January 1, 2011), and
    ii. After transition (on or after January 1, 2011).

d) Please provide the following information in detail for overhead/burden costs on self-constructed assets for the bridge and test years.

Nature of the Overhead Costs	Dollar Impact: Bridge Year	Dollar Impact: Test Year	Directly Attribut-able Yes/No	Reasons for Capitalization (MIFRS Principles)
1.				
2.				
3.				
4.				

e) Please identify the overall level of increase (decrease) in OM&A expense in the bridge and test year in relation to a decrease (increase) in capitalized overhead.

f) Please confirm that all borrowing costs that are directly attributable to the acquisition, construction, or production of PP&E costs are capitalized to PP&E and not expensed. If this is not the case, please explain.

g) Were the incurred debts (e.g. demand loan, smart meters, etc.) acquired on an arm's length basis?

h) Were the actual borrowing costs (in "d" above) capitalized for rate making purposes? If not, please explain.

i) If not acquired at arm's length, what are the actual interest rates and interest borrowing costs used? Were they greater than the Board's most recently published CWIP interest rates?

j) Please confirm that, if the interest rate used in "i" above is greater than the Board's most recently published CWIP interest rates, HHHI has used the Board's published rates to calculate borrowing costs included in the construction costs. If this is not the case, please explain.

k) Concerning HHHI's practice of not capitalizing interest on funds used during construction as capital projects are budgeted for and completed in the fiscal year, please state how many months in the fiscal year would the capital projects be completed.

l) How long do the interest rates on the borrowed funds used for construction in "g" above run for?

m) Please confirm that HHHI followed the standard in IAS 23. If not, please explain.

5.
Reference: Exhibit 2 / 2 / 1 / p.6

There is no entry in Table 2-11a 'Asset Continuity Schedule' for Communications Equipment (Smart Meters) under account 1955.

Where is the capital cost of the infrastructure associated with Smart Meters accounted for?

6.
Reference: Report of the Board *'Transition to International Financial Reporting Standards ("IFRS")* July 28, 2009 [EB-2008-0408];

IFRS requires certain assets to be recorded as intangible assets (e.g. computer software and land rights) that were previously included in PP&E.

The Board Report has said at p. 40:

> *Where IFRS requires certain assets to be recorded as intangible assets that were previously included in PP&E (e.g. computer software and land rights), utilities shall include such intangible assets in rate base and the amortization expense in depreciation expense for determining revenue requirement.*

HHHI did not present in Exhibit 2 the accounting policy change on asset reclassification from PP&E to intangible assets.

a) Has HHHI identified the accounting policy change on asset reclassification from PP&E to intangible assets? If so, please provide the accounting policy change and quantify the changes due to the adoption of IFRS for the test year and bridge year. If not, please provide the reasons and the plan when this is to be addressed.

b) For the assets identified in (a), please propose a regulatory treatment in accordance with the Board report.

7.
Reference: Exhibit 2 / 1 / 2, pp. 9 & 13

For underground switchgear, HHHI stated at p. 9:

> *Kinectrics identifies a useful life between 20 and 40 years, with a typical useful life of 30 years based on low mechanical stress and 4 electrical loading and high environmental factors. Environmental factor is high as the assets tend to rust as they sit at the side of the road, so the snow, debris, salt, etc. factor into the condition of the asset. The approximate age is 25 to 30 years; therefore HHHI has decided a useful life of 30 years is appropriate.*

At p. 13 'Table 2-4: PP&E Components and Estimated Useful Life', HHHI has proposed a useful life of 20 years instead of 30 years for underground switchgear.

> Please clarify the figure for the useful life of the underground switchgear that HHHI has decided is appropriate, and make any necessary changes to subsequent tables.

8.

Reference: Exhibit 2 / 1 / 2 / pp. 12-13

HHHI application has a life of 3 years and two years for computer hardware and software respectively. Hardware assets have had expected useful life of 5 years, and for software it has often been 3 – 5 years. Table 2-4 shows that HHHI has used a one-year period for software.

a) Please provide the basis for HHHI's proposal for 3 and 2 year useful lives.

b) For how long has HHHI used a one-year life for computer software?

9.

References: Exhibit 2 / 2 / 4 / p. 2; Exhibit 2 / 2 / 5 / p. 1

In Exhibit 2 / 2 / 5, HHHI states: "In 2009 and 2010, HHHI removed $869,000 and $367,000 respectively from accumulated depreciation for stranded meter costs as a result of the Smart Meter project." However, Table 2-19 shows variances that are much smaller than these amounts for Account 1860 - Meters.

Please provide a reconciliation between these two tables in these two exhibits.

10.

Reference: Exhibit 2 / 3 / 3 / p. 3

HHHI indicates that it is well underway toward completion of a formal Asset Management Plan.

When does HHHI expect to finalize its initial Asset Management Plan?

Gains and Losses on Retirements and Impairments

11.

Reference: Report of the Board *Transition to International Financial Reporting Standards* ("IFRS") July 28, 2009 [EB-2008-0408]

Under IFRS, asset retirement obligations include estimates of the cost of constructive obligations which was not required under CGAAP, and a revaluation of those obligations during the lives of the assets. HHHI did not present the accounting policy change on treatment of asset impairment.

The Board Report has stated as follows, at p 40:

> *Utilities shall identify separately in their rate applications the depreciation expense associated with amortizing asset retirement costs and the accretion expense associated with the amortization of the asset retirement obligations. The Board will*

assess these costs independently of other amortization costs to determine the portion, if any, of these costs that should be recovered in revenue requirement.

At p. 19:

Where a utility for financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings the utility shall reclassify such gains and losses as depreciation expense and disclose the amount separately. Where a utility for financial reporting purposes under IFRS has reported a gain or loss on disposition of individual assets, such amounts should be identified separately in rate filings for review by the Board.

At p. 41:

Where for financial reporting purposes under IFRS a utility has recorded an asset impairment loss, for rate application filings such losses shall be reclassified to PP&E and identified separately to allow consideration of whether and how such amounts are to be reflected in rates.

a) Please confirm whether or not HHHI has any Asset Retirement Obligations ("ARO").
    i. If yes, please identify and provide a detailed breakdown of the major asset components.
    ii. If no, please provide a proposal for how the asset retirement obligations should be recovered in rates.
b) If HHHI has AROs, please confirm whether or not HHHI has identified the accounting change on AROs.
    i. If so, please provide the accounting change and quantify the changes due to the adoption of IFRS for the test year and bridge year.
    ii. If not, please provide the reasons and the plan when this is to be addressed.
c) For the AROs identified, please provide the depreciation expenses and accretion expenses and show how these expenses are currently included in the rate application.
d) Please confirm that HHHI has identified the gain or loss on the retirement of assets in a group of like assets. Please provide the treatment of the retirement for rate application purposes and disclose the amount. If the gains/losses are not charged to depreciation expense please state the reasons.
e) Please disclose any asset impairment loss recorded under IFRS which should be reclassified to PP&E. Please describe:
    i. the nature of the losses;
    ii. the amounts of the losses; and
    iii. whether and how such amounts are to be reflected in rates.

Service Reliability

12.

Reference: Exhibit 2 / 3 / 5 / pp. 2-3

The Reliability statistics in Table 2-28 for 2010 are identical, with and without consideration of loss of supply. However, Table 2-29 shows different statistics with consideration of the Hydro One system

Please explain how these tables can be reconciled; in other words why is the second part of Table 2-28 not more similar to Table 2-29, given that the latter excludes incidents that appear to be a loss of service?

FIT and microFIT Renewable Generation

13.

Reference: Exhibit 2 / Appendix D 'HHHI's Green Energy Plan' / pp. 6-9

Table 3.1 on page 6 of the above-noted Reference provides a Table of microFIT generators connected to HHHI's distribution system with nominal output rating of each generator. Tables 3-2-2 and 3.3 on pages 7-9 show renewable generation projects that are in the queue under the OPA's FIT or microFIT programs but are not yet connected to HHHI's distribution system.

Board staff wishes to get an update on the approval status and an indication of the expected total kilowatt ("kW") output of the generators listed in Tables 3.1 and 3-2-2.

a) Please provide an update on the approval status of the microFIT and FIT projects listed in Tables 3.2.2 and 3.3 and any new applications that are in the queue.

b) Please provide an indication of the expected total kW output of the generators listed in Table 3.1.

c) Please provide an indication of the expected total kW output of the generators listed in Tables 3-2-2 and 3.3 and any new applications that are in the queue.

HHHI's Renewable Generation Initiative

14.
References: Exhibit. 2 / Appendix D HHHI's Green Energy Plan' p. 9; Exhibit 2 / 3 / 7

HHHI indicates in its GEA Plan that in 2010 it undertook a pilot project to install pole-mounted solar photovoltaic panels at selected sites throughout its service territory.
In Exhibit 2 / 3 / 7 HHHI describes the Green Energy Initiative to install solar panels on 1400 utility poles in 2012 at a capital cost of $1.4 million proposed for inclusion in the rate base. Each installation includes a 220 - 280 watt solar panel, a Smart Energy Module with an inverter, two way wireless Smart Grid communicator, sensors, digital meter, and a pole mounting system to attach to existing utility poles. Based on the estimated total capital cost of $1.4 million, this works out to an average of $1000 per pole.

a) Please provide the results of any analysis carried out by HHHI with respect to its 2010 pilot project to install pole-mounted solar photovoltaic panels including costs, benefits, cost/benefit analysis etc.

b) Does the estimated average cost of $1000 per pole for the proposed 2012 solar panel initiative include all costs, e.g. materials, labour, engineering, commissioning, inspections etc? Please provide a breakdown of costs and explanation.

c) Is it HHHI's intention to implement the pole-mounted solar panel project within the context of other HHHI capital and operating programs?

d) What is HHHI's rationale for not considering the pole-mounted solar panel project as a capital project under the HHHI's Green Energy Plan?

Challenges Associated with Distributed Generation

15.
Reference: Exhibit. 2 / Appendix D / pp. 10-14

HHHI describes in this reference the various "challenges" associated with connecting distributed generation to HHHI's distribution system including: impact on special protections, short circuit issues, protection coordination, impact on faulted circuit indicators and issues with shared transformer stations. These are presented as potential issues with no specific solutions, expected costs or a plan to address the issues.

What plan(s), if any, does HHHI have for addressing the potential issues described in the above-noted Reference in 2012 and beyond? Please provide details on scope, schedule, priority and costs.

Distribution System Enhancements for Smart Grid Development

16.
Reference: Exhibit. 2 / Appendix D / pp. 15 - 17

HHHI describes in this reference some proposed enhancements that would contribute to the Ontario government's smart grid objectives including modifications to feeder protections, extending three-phase circuitry into rural areas and consideration of distributed generation connections in the design of new transformer stations.

HHHI states that the estimated cost for the feeder protection changes is about $15,000 per feeder. It also states that, as instances arise, HHHI will extend the three-phase aerial circuitry based on a cost sharing arrangement with the generator, in accordance with the Transmission System Code. Based on that, HHHI bears the initial $90,000 per nameplate MW output of investment cost, with the balance borne by the generator.

a) Is HHHI planning to carry out the feeder protection changes on all its feeders or as needed to accommodate new generator connections? Please explain.

b) Please provide an estimate of the cost HHHI expects to incur and the timeframe for the feeder protection changes.

c) Please provide an estimate of the cost HHHI expects to incur and the timeframe for extending three-phase circuitry into rural areas.

d) Please explain HHHI's rationale for categorizing the above-noted enhancements as Smart Grid development and identify information on the Smart Grid technologies that are utilized.

e) If the estimated costs for the above-noted enhancements are not entirely Smart Grid related, please provide a breakdown that indicates the portion that is Smart Grid related and the portion that is related to connection of renewable generation.

Cost Recovery of Green Energy Plan Costs

17.
Reference: Exhibit. 2 / Appendix D / p. 19

HHHI states in this reference that it is not seeking to recover costs related to the connection of renewable generation in the form of a short term rate rider at this time.

Please explain why HHHI has chosen not to seek cost recovery of Green Energy Act Plan costs at this time.

Other Distribution Revenue

18.
References: Exhibit 3 / 3 / 1; Exhibit 4 / 1 / 1 / p. 13; Exhibit 4 / 2 / 4 / p. 2-3

a) Please confirm that the revenue shown in Table 3-23 account 4375 is the same as the inter-affiliate revenue derived in Table 4-14.

b) Please identify any allocation factors in Exhibit 4 / 2 / 4 / p. 2-3 that might vary substantially from year to year. If most of the allocators are stable, please explain why the forecast of account 4375 remains stable at $396,000 at the 2011 level, rather than increasing with OM&A costs (e.g. at 31.5% per Table 4-6).

c) Is revenue from microFIT generators included in one of the accounts in Table 3-23? If so, in which account is it included and how much revenue is gained?

Operation Maintenance and Administration

19.
References: Exhibit 4 / 1 / 1; Exhibit 4 / 2 / 1 / p. 5

In Tab 1, Tables 4-2, 4-3, 4-4, 4-5 and 4-6, HHHI provide the following with respect to Meter Reading Expenses (Account 5310):

Year	2008 Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
Meter Reading Expense	$147,000	$134,104	$134,696	$131,177	$16,300	$206,840

On page 5 of Exhibit 4 / 2 /1, HHHI states:

Meter reading services have, historically, been contracted out to a non-affiliated third party under a service contract agreement. Effective June 1, *2011 HHHI started billing Residential and General Service less than 50 kW customers on a Time-of-Use basis using smart meters.*

a) Please confirm that the costs of the third party contract were recorded in account 5310 as shown in the above table.
b) Please explain the decrease in meter reading expenses in 2011 of $16,300 compared to approximately $135,000 per annum from 2008 to 2010.
c) Please explain the forecasted increase in Meter Reading Expenses for 2012, relative to:
    i. 2011; and
    ii. the historical norm of approximately $135,000 per annum.

20.
Reference: Exhibit 4 / 2 / 3 / p. 7

The increased cost of Billing and Collecting is due in part to "the addition of a Billing Clerk for succession planning purposes".

a) Please provide information on the expected length of time that there will be an overlap of the incumbent and the proposed new clerk, during the test year, and if applicable beyond the test year.

b) Assuming that the overlap is considerably less than the period of the IRM adjustments following this cost-of-service application, has HHHI considered applying an adjustment factor to the increase requested for the test year revenue requirement?

21.
Reference: Exhibit 4 / 2 / 3 / pp. 6-7

a) Please provide further explanation of the $76,000 identified for "smart meter communication costs" as a driver for the increase of $297,106 for Account 5315 – Customer Billings.
b) Is this a recurring cost, or one-time cost in 2012 only?

22.
Reference: Exhibit 4 / 2 / 3 / p. 7

The increased cost of Billing and Collecting includes $76,000 in Smart Meter communication costs.

a) Please provide a description and breakdown of these costs.
b) Are there any labour or other costs that will be reduced, immediately or in the foreseeable future, that would tend to offset this increased communication cost.

23.
References: Letter of the Board 'Use of Modified IFRS as a Basis for Filing Cost of Service Applications for 2012 Rates', March 15, 2011; Exhibit 4 / 1 / 1 / p. 1

HHHI stated in Exhibit 4 / 1 / 1, at p. 1:

> *The operating costs presented in this Exhibit represent the annual expenditures required to sustain HHHI's distribution operations. HHHI follows the Board's Accounting Procedures Handbook (the "APH") in distinguishing between operations and maintenance work. A summary of HHHI's operating costs for 2008 Board Approved, 2008 Actual, 2009 Actual, 2010 Actual, 2011 Bridge Year and the 2012 Test Year and the variances year over year, in accordance with the Filing Requirements, is presented below. HHHI has provided the required 2008 Board Approved to 2010 Actual based on CGAAP and 2011 Bridge Year and 2012 Test Year based on Modified IFRS.*

In the March 2011 letter the Board provided a revised version of paragraph 9.1.2 of the Board Report:

> *Electricity distributors filing cost of service applications for rates for 2012 should make all reasonable efforts to provide the forecasts for the 2012 test year (and any other subsequent test years) in modified IFRS accounting format. In addition, the electricity distributor must provide the required actual years, the bridge year and the forecasts for the test year(s) in CGAAP-based format. Further, the electricity distributor must identify financial differences and resulting revenue requirement impacts arising from the adoption of modified IFRS accounting. A distributor for whom the filing of the forecasts for the 2012 test year in modified IFRS is an unreasonable burden and that files under CGAAP must include in its rate application an explanation of the reason for filing under CGAAP and a plan for the transition to modified IFRS accounting as a basis for setting its rates.*

HHHI did not provide the bridge year and test years forecasts in CGAAP based format, as required by the Board.

a) Please provide all applicable schedules, e.g., operating costs, etc. for the bridge year and tests year under CGAAP similar to the ones reported under an IFRS regime

b) Please identify the financial differences and resulting revenue requirement impacts arising from the adoption of modified IFRS accounting.

24.

References: Report of the Board *'Transition to International Financial Reporting Standards'* ("IFRS") July 28, 2009 [EB-2008-0408]; Exhibit 4 / 2 / 7 / p. 1

HHHI stated:

> *HHHI uses the pooling of assets for all fixed assets with the exception of Computer Equipment/Software, Automotive Equipment, Furniture & Equipment, Communication Equipment, and Capital Tools.*

Useful lives for PP&E are to be reviewed at least at each financial year-end with MIFRS.

The Board's policy articulates that LDCs shall use the Board sponsored Kinectrics study or sponsor their own study to justify changes in useful lives. The typical useful lives (TUL) from the Kinectrics report is the recommended Reference point. The Board will no longer prescribe service lives for PP&E.

Salient points from the Board Report are as follows, at p. 21:

> *The Board will facilitate a joint depreciation study for electrical distribution utilities. The aim of the study will be to determine depreciation methodologies and rates that will be applied to all electrical distribution utilities for the purpose of setting rates and regulatory reporting. The study must give due weight to the IFRS requirements regarding depreciation, including componentization.*
>
> *The Kinectrics Report provides information that the Board expects distributors will consider as they develop asset service lives suitable in their particular circumstances. The Board expects distributors to reflect their consideration of the information contained in the Kinectrics Report when they present an IFRS-based rates application to the Board.*

For the bridge and test years, please confirm if HHHI :

a) used componentization for the underlying PP&E assets, including gross capital costs and accumulated depreciation values and not pooling of assets (i.e. pool assets is not permitted)

b) depreciated separately the significant parts or components of each item of PP&E.

c) used the revised useful lives, and calculated the depreciation expense based on revised service lives. In addition, please provide the calculation required.

d) if the answer in “c” above is “no”, please explain and provide the changes in depreciation expenses and accumulated depreciation for the bridge and test years.

Low Income Energy Assistance Program (LEAP)

25.
References: Exhibit 3 / 1 / 1 / p. 1; Exhibit 4 / 2 / 3 / p. 9

The Board’s Filing Requirements, dated June 22, 2011, section 2.7.2.3 state that a distributor should commit 0.12% of its distribution revenue requirement to emergency financial assistance, and clarifies that the revenue requirement is the forecasted service revenue requirement. HHHI has identified its service revenue requirement as $11,237,701 at the Reference in Exhibit 3. However, the revenue requirement used by HHHI is $10,714,114 and the LEAP provision is rounded up to $13,000.

a) Please provide an alternative calculation based on the service revenue requirement described in Exhibit 3.

b) Please state whether or not HHHI has included an amount in its 2012 Test year revenue requirement for any legacy program(s), such as Winter Warmth. If so, please identify the amount and provide a breakdown identifying the cost of each program along with a description of each program.

Charitable Donations

26.
References: Exhibit 4 / 2 / 2 / p. 2; Exhibit 4 / 2 / 3 / pp. 2 & 9

a) Please describe the forecasted charitable donations in detail, in particular whether they are designed to provide assistance to HHHI’s customers for purposes described in the Board’s Filing Requirements, June 22, 2011,section 2.7.2.5.

b) Please explain why HHHI’s annual donations have fluctuated since 2008 over a range from less than $7000 up to nearly $30,000, and why the forecasted amount is at the top of this range.

c) Charitable donations are shown as $0 in the 2010 PILs return (Exhibit 4 / Appendix D) and in the test year PILs spreadsheet filed with HHHI’s pre-filed evidence, but are shown as $6489 and $30,000 respectively in Table 4-9.

Should these entries be the same in both places, and if so which are the right numbers?

d) Table 4-10 (Exhibit 4 / 2 / 3 / p. 2) shows a $20,905 reduction in charitable donations as a cost driver, which is apparently inconsistent with the request for approval of $30,000. Please explain or correct this inconsistency.

Provision for PILs

27.
References: Excel file Test Year Income Tax, Sheet T ‘PILs,Tax Provision’; Exhibit 4/3/1

a) Please confirm that the capital tax rate applicable to Capital Tax in 2010 in Table 4-24 should be 0.075%, i.e. half of 0.15%, rather than 0.75% as shown.

b) The tax rate assumed in the pre-filed Excel spreadsheet (item M in worksheet T) is 15.5%. The rate used in Table 4-24 in Exhibit 4 is 26.5%. Please reconcile these assumptions and/or provide an explanation of this apparent inconsistency.

c) Grossed-up PILs in the pre-filed Excel spreadsheet (item U in worksheet T) is $67,791. Income Tax in Table 4-24 in Exhibit 4 is $131,542. Please reconcile these assumptions and/or provide an explanation of this apparent inconsistency.

Smart Meter Entity

28.
References: Exhibit 4 / 2 / 3 / p. 6; Board Decision, Powerstream [EB-2010-0209], p. 14

HHHI has included a forecast cost of $135,000 for its cost from a fee from the IESO for the Smart Meter Entity.

a) Please describe the assumptions made by HHHI in formulating this amount.

b) Was HHHI aware of the referenced Board Decision denying Powerstream’s request to cover a forecast MDM/R cost forecast on the basis that it was premature, at least until such time as the Board approves an IESO fee for the service?

Inflation Rate

29.
Reference: Exhibit 4 / 1 / 1 / p. 2

With Reference to the Statistics Canada source cited in the footnote to Table 4-1, it is not clear how the inflation index used by HHHI was derived from that source. Please provide additional information on the inflation index of 1.0%, used to prepare HHHI's test year forecast of expenditures.

Please explain

a) whether the index was applied for 12 months or only 6 months,
b) whether the index included all consumer-good categories or did it exclude some categories,
c) whether the index was seasonally adjusted.

Affiliate Transactions

30.

Reference: Exhibit 4 / 2 / 5 / p. 2; Exhibit 4 / Appendix B

Table 4-15 is titled **"**Purchases of Services from Non-Affiliate Suppliers". The preamble of each of the Service Agreements filed in Appendix B provides for the affiliate to "provide various services" to HHHI.

> Please confirm that the revenue requirement does not include a component of cost of any such services; otherwise please provide a table similar to Table 4-15 for the costs of services from affiliate suppliers.

Depreciation

31.

Reference: Exhibit 4 / 2 / 7 / p. 6

a) Total Depreciation in Table 4-23 is $1,834,363, and depreciation in the RRWF 'Revenue Requirement' is $1,624,165. Which amount is correct?

b) Several accounts do not have an asset life entered in column 'f' of Table 4-23, and the corresponding depreciation rate in column 'g' is also blank. Please provide the missing data, or an explanation of why it is missing.

c) Some of the accounts have no depreciation expense in column 'h', despite having a net fixed asset balance in column 'e', for example Account 1955.

Please provide amounts for column ‘h’ if there should be an amount, or an explanation of why it should be blank.

d) Some accounts have depreciation amounts in column ‘h’ that do not appear to be based on the formula, for example Account 1915. Please provide an explanation of how the formula was used or an explanation of when it is to be over-ridden.

Ontario Municipal Employees Retirement System Pension Costs

32.

Reference: Exhibit 4 / 2 / 6

HHHI has submitted in the reference, at p. 5, that it has

> *“anticipated an increase in OMERS pension costs regarding a 3-year, 1% per year increase in OMERS premiums beginning in 2011. OMERS estimates the 1% contribution rate increase in 2011 would increase the amount an employer contributes to OMERS by about 10-13%”*

HHHI has also provided Tables 4-16, 4-17 and 4-18 showing Compensation and Benefits, OMERS Pension Premiums, and Employee Future Benefits respectively.

Please explain how HHHI made its forecast of OMERS premiums in the test year (which is an increase of $160,000 or approximately 75% more than 2010 actual in Table 4-17), and relate this to the increase in its forecast of salary and wages (which is approximately 20% more than 2010 actual).

Treatment of Pensions and Other Post-Employment Benefits

33.

References: Exhibit 4 / 2 / 6 / p. 6 ; Exhibit 4 / Appendix C ‘Report on the Actuarial Valuation of Post-Retirement Non-Pension Benefits’

The cover sheet of the report filed as Appendix C notes that it is a draft version dated March 23, 2010.

a) Has the report been finalized in the meantime? Is there a signed version of p. 19? If not, why not?

b) If the report has been finalized, please provide any changes that were made to the draft that HHHI has filed.

c) If the actuarial report is used in formulating the information in Table 4-18, “Employee Future Benefits”, please indicate which results in the report are linked to HHHI’s actual or forecasted information in Table 4-18.

34.
References: IASB revisions to IAS 19, Employee Benefits, June 2011; Exhibit 4 / Appendix C 'Report on the Actuarial Valuation of Post-Retirement Non-Pension Benefits'

The IAS revisions are effective January 1, 2013, but early adoption is permitted. These revisions include the elimination of the option to defer recognition of gains and losses, known as the "corridor method".

a) Please confirm if HHHI has unamortized actuarial gains and losses and past service costs at the date of transition (January 1, 2011).

b) If yes, what is the accounting treatment of the unamortized actuarial gains and losses and past service costs at the date of transition (January 1, 2011)?

c) What is the proposed regulatory treatment of these amounts – are these amounts incorporated into the revenue requirement? Please explain.

d) Please confirm whether or not HHHI has adopted the revisions to IAS 19, Employee Benefits, and state whether the impacts of this early adoption are incorporated in the revenue requirement.

Cost of Capital

35.
Reference: Exhibit 5 / 1 / 1

a) Please provide a copy of the Promissory Note that is held by the Town of Halton Hills.

b) Have there been any changes to the note since it was first issued? If so please explain, and provide copies of the amendments.

c) Does the note have a fixed rate or is it variable or re-negotiated periodically? Please explain.

d) Please reconcile the information in Tables 5-2 through 5, which show a rate of 6.00%, with Table 5-7 which shows a rate of 6.25%.

Cost Allocation

36.
Reference: Exhibit 7 / 1 / 1 / p. 2; Board Report "Review of Electricity Distribution Cost Allocation Policy", March 31, 2011 [EB-2010-0219]

The Board Report states, at p. 26

> *The Board is of the view that default weighting factors should be utilized only in exceptional circumstances….. [A]ny distributor that proposes to use those default values will be required to demonstrate that they are appropriate given their specific circumstances.*

Has HHHI adopted the default weighting factors as appropriate for itself. If so, please provide documentation as specified in the Board's Report. Alternatively, please provide descriptions and weighting factors for Services and Billing Costs, and a calculation of the impact on the respective class revenues.

37.

Reference: Exhibit 7 / Appendix A and B

Exhibit 7 / Appendix B consists of several worksheets from an alternative run of the cost allocation model, which appear to differ from the worksheets in Appendix A only with respect to Miscellaneous Revenue, with the total in Appendix B being larger by $50,000.

a) Please confirm that this is the only difference, and that the version in Appendix A is consistent with the remainder of the application.

b) Please explain which revenue account(s) differ between the two versions, and what assumptions have been made underlying both versions of the cost allocation model.

38.

Reference: Exhibit 1 / 1 / 11; Board Report "Review of Electricity Distribution Cost Allocation Policy", March 31, 2011 [EB-2010-0219]

In HHHI's previous cost-of-service application the Board approved the situation in which HHHI would charge its General Service 1000-4999 kW rates to Hydro One at two delivery points (EB-2007-0696, Decision p. 18). The Decision noted that the situation was under review more generally and instructed HHHI to remain up-to-date on the matter. In this application, HHHI has stated that it is not a host distributor.

a) Does HHHI continue to provide power to Hydro One at the delivery points discussed in the previous proceeding? If not, in which year did this situation change?

b) Please confirm that there are no other similar delivery points to Hydro One or another distributor?

c) If HHHI continues to deliver power to Hydro One, does HHHI have a proposal that future treatment of Hydro One as an embedded distributor that would be consistent with changes in the Board's cost allocation policy at p. 32 of the referenced Report?

Total Loss Factor

39.
References: Exhibit 2 / Appendix C / p. 15; Exhibit 8 / 4 / 1

a) Please provide a calculation of the Total Loss Factor ("TLF")based on the most recent three-year history, together with an explanation of why the TLF being applied for should include the relatively high losses incurred in 2006 and 2007.

b) Has HHHI considered that its voltage conversion capital projects described in Exhibit 2 may decrease line losses? If so, does it expect that any improvements would reverse the trend of increased Distribution Loss Factor ("DLF") shown in row G, Table 8-9? If it has not considered the possibility of this favourable outcome in DLF, why not?

Retail Transmission Service Rates

40.
Reference: Exhibit 8 / 3 / 1; RTSR Adjustment Work Form

Worksheet '8 – Forecast Wholesale' shows that HHHI's wholesale cost includes a component of about 10% being established by the IESO's Uniform Transmission Rates. HHHI's evidence is that it is totally embedded, which would seemingly imply that only Hydro One's Sub-Transmission RTSRs would establish the wholesale cost.

Please provide an explanation of this apparent inconsistency, together with any additional evidence or corrections that may be necessary.

Retail Service Charges

41.
References: Exhibit 8 / 8 / 4 / p. 7; Exhibit 9 / 3 / 1 / p. 2

The balance in Account 1518 proposed for disposition in Exhibit 9 is $31,418 credit.

a) Please provide a description of the incremental costs that affect Account 1518, and a schedule of the approximate amount of incremental cost recorded in these accounts.

b) Please provide the approximate annual revenue from each of the Retailer Charges that affect Account 1518, i.e. charges for establishing a service agreement, monthly fixed and variable charges, and billing-related charges.

c) Please confirm that HHHI's accounting practices are consistent with Article 490 of the Accounting Procedures Handbook, with respect to offsetting entries of incremental cost amounts from operating accounts, for example from Account 5340 to the variance account.

d) Has HHHI considered a change to any of the retail service charges to more closely match the corresponding incremental cost?

Credit Card Convenience Fee

42.

Reference: Exhibit 8 / 8 / 4 / p. 6

a) HHHI's Conditions of Service, found on its web-site, identifies at p. 23 that a convenience fee will be charged on security deposits made by credit card. Please provide an explanation for the nature of the costs being recovered by this fee.
b) HHHI's Conditions of Service identifies at p. 26 that a Board-approved fee may be charged for certain requests for aggregated customer information. Please provide an explanation for the nature of the costs being recovered by this fee.
c) Please explain whether in the applicant's view, these rates and charges should be included on the applicant's tariff sheet, for example amongst its proposed Specific Service Charges.

Deferral and Variance Accounts

43.
Reference: Exhibit 9, Tab 2, Schedule 1, Page 13; Exhibit 9, Appendix B-DVA Continuity Schedule Work Form; Chapter 2 of Filing Requirements

The Provincial Sales Tax (“PST”) and the Federal Goods and Services Tax were harmonized into the Harmonized Sales Tax (“HST”) effective July 1, 2010. As a result of this harmonization, applicants may benefit from an overall net reduction in costs in the form of Input Tax Credits (“ITCs”). This arises due to cost decreases from the receipt of additional ITCs on the purchases of goods and services previously subject to PST that become subject to the HST. These cost decreases may be partially offset by cost increases on certain items that were not previously subject to PST but become subject to the HST with no additional ITCs having been granted (i.e., these items are subject to recaptured ITC requirements).

During the 2010 IRM application process, the Board directed electricity distributors to record in Account 1592 PILs and Tax Variances, Sub-account HST/OVAT Input Tax Credits (“ITCs”), beginning July 1, 2010, the incremental ITCs received on distribution revenue requirement items that were previously subject to PST and became subject to HST.

The Board provided accounting guidance on this matter and provided a simplified approach designed to facilitate administrative cost-saving opportunities. [Frequently Asked Questions on the Accounting Procedures Handbook, December 23, 2010]

No additional amounts should be recorded in Account 1592 PILs and Tax Variances, Sub-account HST/OVAT ITCs for the Test Year and going forward, as the impact of the HST and associated ITCs on capital and operating costs in the Test Year should be reflected in the applied-for revenue requirement. For the 2012 Test Year for example entries to record variances in the sub-account of Account 1592 would cover the period July 1, 2010 to December 31, 2011 since the Test Year, which starts January 1, 2012 would include the HST impacts in it revenue requirement for 2012.

In Chapter 2, the Board expects distributors to file for disposition of account 1592 in their cost of service applications.

HHHI’s application is as follows (Exhibit 9 / 2 / 1 / p. 13):

> *HHHI requests leave to discontinue tracking HST/OVAT/ITC as at April 30, 2012. HHHI also requests the Board allow that account 1592 remain open, pending Board approval to discontinue tracking costs effective April 30, 2012 and until such time as*

HHHI files its 2014 IRM rate application at which time HHHI will apply to the Board for an order to clear any audited debit or credit balance remaining in account 1592.

a) Please explain why HHHI is not requesting disposition of Account 1592.

b) Please complete and file Appendix 2-T Deferred PILs Account 1592 Balances from Chapter 2 of the Filing Requirements (June 22, 2011).

44.

Reference: Exhibit 9, Tab 2, Schedule 3, Page 4; Chapter 2 of the Filing Requirements: Section 2.12.3; Exhibit 9, Tab 2, Schedule 1, Page 8

According to the Board letter of April 23, 2010 on the Special Purpose Charge:

In accordance with section 9 of the SPC Regulation, recovery of your SPC assessment is to be spread over a one-year period, starting from the date on which you begin billing to recover your assessment. The request for disposition of the balance in "Sub-account 2010 SPC Variance" and "Sub-account 2010 SPC Assessment Carrying Charges" should be made after that one-year period has come to an end, and all bills that include amounts on account of that assessment have come due for payment.

Chapter 2, Section 2.12.3 of the Filing Requirements states:

In accordance with Section 8 of the SPC Regulation, distributors are required to apply no later than April 15, 2012 for an order authorizing the disposition of any residual balance in sub account 2010 SPC Assessment Variance.

The Board expects that requests for disposition of the balance in Sub-account 2010 SPC Assessment Variance and associated carrying charges will be addressed as part of the proceedings to set rates for the 2012 rate year. Exceptions may apply in cases where this approach would result in non-compliance with the timeline set out in section 8 of the SPC Regulation.

HHHI stated:

HHHI established account 1521 Sub-account 2010 SPC Variance, and Sub-account 2010 SPC Assessment Carrying Charges in accordance with the Board's April 23, 2010 letter. HHHI's share of the Assessment for MEI Conservation and Renewable program of $189,128 was recognized in this account in April 2010, and customer billing for recoveries commenced May 1, 2010. As per the Board's instructions in the letter dated April 9, 2010, HHHI has recovered the SPC assessment over a one-year period on consumption after May 1, 2010 (pro-rated). As HHHI bills residential customers bi monthly, final SPC charges have been billed as of August 15, 2011. HHHI requests the Board allow that account 1521 remain open until such time as HHHI files its 2013 IRM rate application at which time HHHI will apply to the Board for an order to clear any audited debit or credit balance remaining in account 1521.

a) Please provide the most recent balance in account 1521, “Sub-account 2010 SPC Variance”.

b) Please provide the forecasted carrying charges in “Sub-account 2010 SPC Assessment Carrying Charges” as of April 30, 2011.

c) Please explain why HHHI is not seeking the disposition of the residual balances in account 1521 sub-account 2010 SPC Assessment Variance and sub-account 2010 SPC Assessment Carrying Charges in accordance with the Board’s April 23, 2919 letter and Section 2.12.3 of the Filing Requirements.

d) Is HHHI in non-compliance with the timeline set out in Section 8 of the SPC Regulation? Please explain.

45.
Reference: Exhibit 9, Tab 3, Sch. 2, Page 3

The proposed rate riders for non-RPP customers in the Residential and GS<50 kW classes in Table 9-13 appear to be inconsistent with the sub-account balances in Table 9-9 and the billing kWh amounts in Table 9-8.

Please verify the amounts in Table 9-8 and 9-9 and show the derivation of the non-RPP rate riders for those classes.

46.
References: Exhibit 8 / 7 / 1; Exhibit 9 / 3 / 2 / p. 3; Board Report *‘Electricity Distributor Deferral & Variance Account Review’* (EDDVAR) July 31, 2009; Exhibit 8 / Appendix A.

HHHI has requested a two-year period for the Deferral and Variance Account Disposition Rate Rider.

The EDDVAR Report states at p. 24:

… the default disposition period used to clear the Account balances through a rate rider should be one year. However, a distributor could propose a different disposition period to mitigate rate impacts or address any other applicable considerations, where appropriate.

a) On the Group 1 and Group 2 Deferral and Variance Account (DVA) rate rider and Non-RPP Global Adjustment rate rider by classes, please explain why HHHI is proposing 2 years instead of 1 year for the disposition period.

b) If the reason for proposing a 2-year recovery is based on a bill impact mitigation study, please provide the calculations.

c) Please re-calculate the rate riders and associated bill impacts using a disposition period of one year.

47.

Reference: Report of the Board *'Transition to International Financial Reporting Standards ("IFRS")* July 28, 2009 [EB-2008-0408]; *One-Time Administrative Costs of Transition to IFRS*, section 2.7.2; Exhibit 9 / 2 / 3 / p. 4; Exhibit 9 / Appendix B

The Report of the Board states, at p. 27:

> *The Board will establish a deferral account for distributors for incremental one-time administrative costs related to the transition to IFRS. This account is exclusively for necessary, incremental transition costs and is not to include … ongoing compliance costs or impacts on revenue requirement arising from changes in the timing of the recognition of expenses.*
>
> *The Board will not restrict the IFRS transition costs account by establishing a fixed start date for amounts to be recorded. However, the Board cautions distributors that the amounts in the account will be subject to a prudence review before disposition. The criteria of materiality, causation and prudence will be considered at the time of proposed disposition. Only costs that are clearly driven by the necessity of transitioning to IFRS and are genuinely incremental to costs that would have been otherwise incurred will be recoverable in rates. Any distributor that has IFRS related costs already approved in rates must record, in a variance account, the variances between the previously approved costs and actual costs of transitioning to IFRS.*

The Regulatory Assets Continuity Schedule for sub-account 1508, Deferred IFRS Transition Costs shows a balance of $260,671 as of December 31, 2010.

a) Please confirm the Deferred IFRS transition costs show a debit balance of $260,671 as of December 31, 2010. Otherwise, please identify the costs if it is different.

b) Please provide the breakdown of the costs recorded in the IFRS Deferral sub-account as of December 31, 2010. Please provide explanations for each category of costs recorded in the IFRS Deferral account and indicate how the costs recorded meet the criteria of one-time IFRS administrative incremental costs.

c) Please confirm that no capital costs were recorded in this deferral or variance account, One-Time Administrative Costs of Transition to IFRS. If this is not the case, please explain.

48.

Reference: *Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment*, June 13, 2011; Exhibit 9 / 2 / 3; Staff Discussion Paper, "Transition to IFRS" March 31, 2011 / Appendix A

In the Addendum to the Board Report, Appendix A: "Summary of Board Policy", the Board stated at p. 31:

> *The Board authorizes the creation of a generic IFRS transition PP&E deferral account to record differences arising as a result of accounting policy changes caused by the transition from CGAAP to MIFRS.*

HHHI's request is as follows, at 9 / 2 / 3 / p. 1:

> *HHHI is requesting an Accounting Order to establish a Deferral and Variance account to track the difference relating to PP&E components of rate base as a result of transition to modified IFRS in 2012.*

Differences may arise with Property, Plant, and Equipment balances due to implementing IFRS. HHHI has not provided a calculation or balance in the Board approved PP&E Deferral Account

a) Please confirm if HHHI has performed a calculation or has provided a balance in the Board approved PP&E Deferral Account.

b) If the answer to part "a" above is no, please update the appropriate schedules and calculate a balance for the PP&E Deferral Account.

c) Please provide a breakdown of the amount that is to be recorded in the PP&E deferral account from the transition date to MIFRS that is, as of January 1, 2011. Please provide the supporting analysis of the amounts in this account.

d) Please provide an analysis similar to Appendix A of the *Staff Discussion Paper – Transition to IFRS*. (The paper is available on the Board's web-site *http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2008-0408/Discussion_paper_Transition_to_IFRS_20110331.pdf*

e) Please provide a proposal for the disposition of this deferral account and rationale, referring to the Addendum to the Report of the Board on IFRS.

Smart Meters

49.

Reference: Exhibit 9 / 4 / 1; Board Decision with Reasons, “Combined Smart Meter Proceeding”, Appendix A, August 7, 2007 [EB-2007-0063]

a) Please confirm that HHHI’s costs recorded in Account 1555 and Account 1556 are directly related to the smart meter program and are incremental costs. If this is not the case, please explain.

b) Please confirm that HHHI’s costs recorded in Account 1555 and Account 1556 are in accordance with the Board’s Decision in the Combined Smart Meter Proceeding, Appendix A.

50.

References: Exhibit 9 / 4 / 2 / pp. 1-10; Exhibit 9 / 4 / 3 / p. 2; Board Decision ‘Combined Smart Meter Proceeding [EB-2007-0063]; Board Guideline ‘Smart Meter Funding and Cost Recovery’ [G-2008-0002], October 22, 2008

The Board indicated in its Decision in the Combined Smart Meter Proceeding that certain costs that were considered “beyond minimum functionality” in relation to smart metering system costs can be recovered as part of future distribution rates. These costs may include web presentment, Customer Information System integration with the Meter Data Management/Meter Data Repository (MDM/R), consumer education, reengineering business practice and integration with retailers.

a) Please indicate if HHHI has recorded such costs and tracked them in separate sub-accounts of Account 1555 and separate sub-accounts of Account 1556 for capital expenditures and OM&A expenses, respectively. Please provide a breakdown by sub-account. If this is not the case, please explain and update the evidence.

b) Please confirm that HHHI did not include borrowing costs relating to money borrowed to finance smart meter installations, if any, as part of the Smart Meter Capital Account 1555 or Account 1556. Please identify which USoA account, if any, HHHI uses to record the borrowing costs.

c) As per the Board’s “Guideline: Smart Meter Funding and Cost Recovery” (G-2008-0002) (the “Guideline”), does HHHI use its normal capitalization policy for smart meters? If this is not the case, please provide an explanation.

d) Are the stranded meter costs recorded in Account 1555 comprised of the gross costs of the stranded meters, less any capital contributions, less the accumulated depreciation and less any proceeds from the disposition of the meters?

e) Please confirm that HHHI is not recording a return on smart meters in Account 1555 or Account 1556. Otherwise, please provide an explanation.

51.
Reference: Exhibit 9 / Appendix D

Please rerun and submit a revised version of the Smart Meter Model adjusting for the following two matters:

a) It appears the current (and recent models) calculate compounded interest on funding adder revenues. Please revise the model applying simple interest (i.e. interest on the opening monthly balance of the principal only) on funding adder revenues, and
b) Please revise the model to calculate simple interest expense on the opening monthly balance for OM&A and amortization expenses.

52.
Reference: Exhibit 9 / 4 / 3 / p. 4

Please re-calculate the smart meter disposition rider using the following methodology that is based on the approach approved by the Board in PowerStream's 2010 smart meter application (EB-2010-0209):

(i) Allocate the total revenue requirement for the historical years, as revised per the previous interrogatory, using the following cost allocation methodology:

- Allocate the return (deemed interest plus return on equity) and amortization based on the allocation of Account 1860 in the cost allocation model (CWMC in the cost allocation model)
- Allocate the OM&A based on the number of meters installed for each class
- Allocate PILs based on the revenue requirement allocated to each class before PILs

(ii) Sum the allocated amounts and calculate the percentages of costs allocated to customer rate classes.

(iii) Subtract the revenues generated from the smart meter funding adder from the overall revenue requirement.

(iv) Allocate the amount calculated in part (iii) by using the allocation factors derived in part (ii)

(v) To calculate the smart meter disposition rider, divide the allocated amount by rate class derived in part (iv) by the number of customers in each class, and then divide by 12.

(vi) If the proposed disposition period is greater than 1 year, divide the result of part (v) by the proposed number of years.

LRAM & SSM

53.
Reference: Exhibit 10 / 1 / 3 / p. 1

HHHI states that the results for OPA programs in 2010 are estimates, based on the number of installs or on methods of estimating program savings, and will be updated upon publication of the OPA final results which was expected to come in September 2011.

Please provide the final results for the 2010 OPA programs HHHI delivered. If the final results are not available, please indicate when HHHI expects to receive them.

54.
Reference: Exhibit 10 / 1 / 3 / p. 1

HHHI notes that the reduction in demand related to its CDM programs has been incorporated into the load forecast for May 1, 2012 onward. It further states however, that energy savings related to OPA programs delivered in 2011 have not been captured.

a) Please confirm that HHHI has not included any losses related to 2011 OPA programs in this LRAM application.

b) If part a) is not confirmed, i.e. if HHHI has included losses attributable to 2011 OPA programs, please discuss the rationale for doing so.

55.
Reference: Exhibit 10 / 1 / 3 / p. 4 Table 10-4

HHHI provides a table outlining its LRAM amounts by funding source.

a) Please confirm that HHHI has used the most recently published OPA Input Assumptions lists when calculating LRAM for Third Tranche programs.

b) If HHHI has not used the most recently published OPA Input Assumptions list when calculating LRAM for its Third Tranche programs, please discuss the rationale for not doing so.

56.
Ref: Exhibit 10 / Appendix A ‘Third Party Review …’

IndEco notes in its third party review, at p. 6, that that energy savings for measures installed between 2006 and December 31, 2010 were calculated to April 30, 2012.

a) Please confirm that HHHI is requesting recovery of lost revenues estimated to April 30, 2012 for programs started between 2006 and December 31, 2010.

b) If part a) is confirmed, please discuss the rationale for requesting recovery of estimated lost revenues until April 30, 2012 in the absence of verified program results for both the 2011 program year and January 1, 2012 to April 30, 2012.

c) If part a) is confirmed, please provide an updated LRAM amount exclusive of estimated lost revenues past December 31, 2010.

Bill Impacts

57.
Reference: Exhibit 8 / Appendix A; Exhibit 9 / 3 / 2 / p. 3

a) HHHI prepared bill impact calculations, in consultation with Board staff, for use in the published Notice of Application that differ from the pre-filed calculations in Exhibit 8 and in the Revenue Requirement Work Form Excel spreadsheet. Please provide documentation of the revised bill impact calculations for a Residential customer using 800 kWh per month and a General Service customer in the ‘less than 50 kW’ class using 2000 kWh per month.

b) Impact calculations are included for customers outside the size range for the General Service 50 – 999 kW class (calculations for 2000 and 4000 kW customers), and for the General Service 1000 – 4999 kW class (calculations for 6500 kw – 13,900 kW). Please provide impact calculations for customers with

500 and 999 kW at rates in the smaller class, and for customers over a suitable range within the larger class.

c) Impact calculations are provided in the pre-filed evidence only for RPP customers. Please provide a parallel set of calculations for non-RPP customers, by combining the two proposed rate riders that would apply to the non-RPP customers in each class.

Requests for Accounting Orders

58.
References : Exhibit 1 / 1 / 7; Exhibit 9 / 2 / 3; Exhibit 9 / Appendix C

HHHI is requesting an accounting order to establish a deferral or variance account to track costs incurred in Tier 3 programs prior to Board approval. A prospective budget amount of $1,762,000 is provided in Appendix C "Addendum to Halton Hills CDM Strategy" Table A-2.

a) Please provide the expected timing of expenditures for Board-approved CDM programs and expected timing of Board review (and approval).
b) With reference to Board Frequently-Asked Questions about the Accounting Procedures Handbook, December 23, 2010, # 22, account 1567 appears to meet HHHI's request for approval of an account. Has HHHI reviewed the description of account 1567, and if so, please provide clarification on HHHI's request for approval of an additional account.

59.
References: Exhibit 1 / 1 / 4 / p. 2; Accounting Procedures Handbook, Frequently Asked Questions about the Handbook, December 23, 2010, #22.

HHHI's request is as follows:

Approval to establish a Deferral and Variance account to track costs incurred in the preparation and implementation of Board-Approved Conservation and Demand Management Programs, prior to Ontario Energy Board approval of said programs.

The Board response to the FAQ states, at p. 25:

The account is Account 1567, Board-Approved CDM Variance Account. A *distributor should track its spending for its Board-Approved CDM Programs in this variance account, which should be used to record the difference between the funding awarded for Board-Approved CDM Programs and the actual spending incurred for these Programs.*

a) Please confirm if HHHI has received Board approval for its CDM Programs which HHHI plans to record in the proposed CDM Variance account.

b) Has HHHI incurred actual spending for these Programs?

Updated Revenue Requirement

60.

Reference: Exhibit 1 / 1 / 4 / p. 1

Upon completion of responses to all interrogatories, please identify any adjustments to the proposed base and service revenue requirements that the applicant wishes to make relative to the original application.

Updated RRWF

61.

Upon completing all interrogatories from Board staff and intervenors, please provide an updated RRWF with any corrections or adjustments that the applicant wishes to make to the amounts, including documentation such as an explanatory note or a Reference to an interrogatory response. (Please show the revisions in the middle column of the applicable worksheets, leaving unchanged the leftward columns labelled ‘Initial Application’.)

Halton Hills
HYDRO

Board Secretary
Ontario Energy Board
2300 Yonge St
27th Floor
Toronto, ON M4P 1E4

November 16, 2011

Dear Ms. Walli,

Re: <u>Halton Hills Hydro Inc. Interrogatory Responses to OEB Board Staff in proceeding EB-2011-0271</u>

Halton Hills Hydro Inc. ("HHHI") hereby submits its responses to OEB Board Staff Interrogatories to the Ontario Energy Board ("the Board").

Please find attached to this cover letter:

- 2 paper copies of the Interrogatory Responses to OEB Board Staff in proceeding EB-2011-0271.
- 1 electronic copy of the Interrogatory Responses to OEB Board Staff in proceeding EB-2011-0271.

A copy of the Interrogatory Responses to OEB Board Staff has also been filed through the Web Portal and electronic copies forwarded to all intervenors in EB-2011-0271.

In the event of any additional information, questions or concerns, please contact David Smelsky, Chief Financial Officer, at dsmelsky@haltonhillshydro.com or (519) 853-3700 extension 225, or Tracy Rehberg-Rawlingson, Regulatory Affairs Officer, at tracyr@haltonhillshydro.com or (519) 853-3700 extension 257.

Sincerely,

(Original signed)

David J. Smelsky, CMA
Chief Financial Officer
Halton Hills Hydro Inc.

Cc: Arthur Skidmore, President & CEO, HHHI
Richard King, Counsel to HHHI
Intervenors in proceeding EB-2011-0271

HHHI Response to Board Staff (OEB) Interrogatories EB-2011-0217

1.

Following publication of the Notice of Application, did HHHI receive any letters of comment? If so, please confirm whether a reply was sent to the author of the letter. If confirmed, please file that reply with the Board. If not confirmed, please explain why a response was not sent and confirm if HHHI intends to respond.

Response:

No letter(s) of comment were received following publication of the Notice of Application.

Rate Base Assets

2.

Reference: Exhibit 2 / 3 / 4 / p. 1

International Accounting Standard ("IAS") 16 'Property, Plant and Equipment' states that the cost of PP&E comprises any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.

IAS 23 states that directly attributable borrowing costs are capitalized on qualifying assets only. It also indicated that a qualifying asset is an asset that necessarily takes a substantial period of time to get ready for its intended use or sale.

HHHI stated at the referenced page:

> *HHHI does not capitalize interest on funds used during construction as capital projects are budgeted for and completed in the fiscal year. HHHI capitalizes, through internal cost allocations, any indirect administrative support costs such as Finance, Human Resources or Corporate Services.*

a) Please explain why HHHI capitalizes indirect administrative support costs such as Finance, Human Resources or Corporate Services when IAS 16 states that only "directly attributable" costs can be capitalized. Please identify if and when HHHI will change its policy and practices of capitalizing the indirect administration support costs. If not, why not.

b) It appears that HHHI does not capitalize interest on funds used during construction as capital projects are budgeted for and completed for a period of less than one year. Please confirm.

c) If answer to part "b" is yes, does HHHI concur that IAS 23 requires that directly attributable borrowing costs are capitalized upon qualifying assets that may take a substantial period of time to get ready for its intended use or sale? If so, does HHHI plan to change its capitalization policy for the attributable borrowing costs? If not, why not?

Response:

a) The reference above is in relation to HHHI's Capitalization Policy under Canadian Generally Accepted Accounting Principles (CGAAP). Under IFRS, HHHI will capitalize all costs, including burdens, when the costs are directly attributable to bringing the item of PP&E to the location and condition necessary for it to be capable of operating in the manner intended by management. Any general and indirect administrative support costs currently included in the various burden rates under CGAAP will not be capitalized under IFRS.

b) Historically, HHHI does not capitalize interest on funds used during construction as there has not been the need to borrow funds for the capital projects.

c) Yes, HHHI concurs with IAS 23. Eligible borrowing costs will be capitalized as part of PP&E for all qualifying assets. Interest rate to be used for capitalization will be limited to the OEB's published rate for CWIP for regulatory reporting purposes.

3.
References: Exhibit 2 / 3 / 4 / p. 1; Report of the Board *'Transition to International Financial Reporting Standards'* ("IFRS"), July 28, 2009 [EB-2008-0408]

The Board Report said at p. 15:

> *The utility will file a copy of its capitalization policy, identifying any updates to the policy, as part of its first rate filing after IFRS adoption. Revenue requirement impacts of any change in capitalization policy must be specifically and separately quantified.*

HHHI proposed that its test year be based on the Modified International Financial Reporting Standards ("MIFRS").

a) Please provide a copy of the capitalization policy from the adoption of MIFRS.
b) Please detail all changes to accounting policies arising from the adoption of MIFRS.
c) Please state the impact on the revenue requirement of the changes due to:
    i. Changes to the accounting policies due to MIFRS to each major component of the revenue requirement (e.g. rate base, operating costs, etc), including the overall dollar impact on the proposed revenue requirement,
    ii. Changes to the capitalization policies due to MIFRS to each major component of the revenue requirement (e.g. rate base, operating costs, etc), including the overall dollar impact on the proposed revenue requirement, and
    iii. Other changes to the capitalization since 2008 that are not related to MIFRS to each major component of the revenue requirement (e.g. rate base, operating costs, etc), including the overall dollar impact on the proposed revenue requirement.

Response

a) Please refer to Appendix OEB 1-A.

b) Please refer to Appendix OEB 1-A.

c)
    i. Please refer to HHHI interrogatory response to Energy Probe question 6.
    ii. Please refer to HHHI interrogatory response to Energy Probe question 6.
    iii. No changes to the capitalization policy for 2008, 2009, 2010 and 2011

4.

References: Report of the Board *'Transition to International Financial Reporting Standards* ("IFRS"), July 28, 2009 [EB-2008-0408]; Exhibit 2 / 3 / 4 / p.1

The Board Report has stated at p. 15:

> *The Board will require utilities to adhere to IFRS capitalization accounting requirements for rate making and regulatory reporting purposes after the date of adoption of IFRS.*

IAS 16 Property, Plant and Equipment states that the cost of PP&E comprises of any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.

IAS 23 states that directly attributable borrowing costs are capitalized upon qualifying assets only. It also indicated that a qualifying asset is an asset that necessarily takes a substantial period of time to get ready for its intended use or sale.

The Board Report also stated at p. 40:

> *The Board will continue to publish interest rates for CWIP as it does now. Where incurred debt is acquired on an arms length basis, the actual borrowing cost should be used for determining the amount of carrying charges to be capitalized to CWIP for rate making during the period, in accordance with IFRS. Where incurred debt is not acquired on an arm's length basis, the actual borrowing cost may be used for rate making, provided that the interest rate is no greater than the Board's published rates. Otherwise, the distributor should use the Board's published rates.*

HHHI stated in its Capitalization Policy (Exhibit 2 / 3 / 4):

> *HHHI does not capitalize interest on funds used during construction as capital projects are budgeted for and completed in the fiscal year.*

With respect to the impact of MIFRS on capital expenditures:

a) Please confirm if the costs capitalized are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. If not, please explain.

b) Has HHHI consulted with its external auditors or professional advisors regarding the change in capitalization of overhead within IFRS requirements? If yes, please provide supporting documentation. If not, please identify if there is any plan in the near future for such a consultation.

c) Please identify the burden rates related to the capitalization of costs of self- constructed assets:

i. Prior to transition (from the last rebasing application to January

1, 2011), and

ii. After transition (on or after January 1, 2011).

d) Please provide the following information in detail for overhead/burden costs on self-constructed assets for the bridge and test years.

	Dollar Impact		**Directly Attribut-able**	
Nature of the Overhead Costs	**Bridge Year**	**Test Year**	**Yes/No**	**Reasons for Capitalization (MIFRS Principles)**
1.				
2.				
3.				
4.				

e) Please identify the overall level of increase (decrease) in OM&A expense in the bridge and test year in relation to a decrease (increase) in capitalized overhead.

f) Please confirm that all borrowing costs that are directly attributable to the acquisition, construction, or production of PP&E costs are capitalized to PP&E and not expensed. If this is not the case, please explain.

g) Were the incurred debts (e.g. demand loan, smart meters, etc.) acquired on an arm's length basis?

h) Were the actual borrowing costs (in "d" above) capitalized for rate making purposes? If not, please explain.

i) If not acquired at arm's length, what are the actual interest rates and interest borrowing costs used? Were they greater than the Board's most recently published CWIP interest rates?

j) Please confirm that, if the interest rate used in "i" above is greater than the Board's most recently published CWIP interest rates, HHHI has used the Board's published rates to calculate borrowing costs included in the construction costs. If this is not the case, please explain.

k) Concerning HHHI's practice of not capitalizing interest on funds used during construction as capital projects are budgeted for and completed in the fiscal year, please state how many months in the fiscal year would the capital projects be completed.

l) How long do the interest rates on the borrowed funds used for construction in "g" above run for?

m) Please confirm that HHHI followed the standard in IAS 23. If not, please explain.

Response:

a) If the costs are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management, then as per HHHI IFRS Capitalization Policy (Appendix OEB 1-A) eligible borrowing costs will be capitalized as part of PP&E for all qualifying assets.

b) Yes, HHHI has consulted with its external auditors regarding the change in capitalization of overhead within IFRS requirements. Please refer to Appendix OEB 1-A

c) HHHI burden rates related to the capitalization of costs of self- constructed assets is presented below in Table OEB 1-1.

Table OEB 1-1 : HHHI Burden Rates

HHHI Burden Rates			
	Effective 1-Sep-10	Effective 1-Apr-11	Effective 1-Apr-12
Hourly Labour Charge	$ 78.45	$ 67.08	$ 67.08
Equipment Rates:			
Single Bucket Truck	$ 44.50	$ 46.00	$ 47.50
Double Bucket Truck	$ 44.50	$ 46.00	$ 47.50
Digger Derrick	$ 44.50	$ 46.00	$ 47.50
Dump Truck	$ 44.50	$ 46.00	$ 47.50
Tension Puller	$ 44.50	$ 46.00	$ 47.50
Pick-up Truck	$ 24.00	$ 25.00	$ 26.00
Van	$ 24.00	$ 25.00	$ 26.00
Skidsteer	$ 24.00	$ 25.00	$ 26.00
Fork Lift	$ 24.00	$ 25.00	$ 26.00
Pole Trailer	$ 14.50	$ 15.00	$ 15.50
Reel Trailer	$ 14.50	$ 15.00	$ 15.50
Material Overhead Rate	22%	12%	12%

d) Please refer to the Capitalization – Burden section of the IFRS Capitalization Policy provided in Appendix OEB 1-A.

e) The Bridge and Test OM&A increase by $206,419 and $286,621 respectively in relation to the decrease in capitalized overhead.

f) There were no borrowing costs incurred that are directly attributable to the acquisition, construction, or production of PP&E. Borrowing costs related to smart meters are currently recorded in OM&A and are not part of PP&E.

g) Yes.

h) Please refer to response to part f).

i) Not applicable, as the incurred debt is on an arm's length basis.

j) Not applicable.

k) Less than six (6) months.

l) Term loan to August 30, 2012.

m) HHHI confirms that the standard in IAS 23 – Borrowing Costs is correctly followed. See Appendix OEB 1-A.

5.
Reference: Exhibit 2 / 2 / 1 / p.6

There is no entry in Table 2-11a 'Asset Continuity Schedule' for Communications Equipment (Smart Meters) under account 1955.

Where is the capital cost of the infrastructure associated with Smart Meters accounted for?

Response:

All capital costs for smart meter have been included in USoA Account 1860.

6.
Reference: Report of the Board *'Transition to International Financial Reporting Standards ("IFRS")* July 28, 2009 [EB-2008-0408];

IFRS requires certain assets to be recorded as intangible assets (e.g. computer software and land rights) that were previously included in PP&E.

The Board Report has said at p. 40:

> *Where IFRS requires certain assets to be recorded as intangible assets that were previously included in PP&E (e.g. computer software and land rights), utilities shall include such intangible assets in rate base and the amortization expense in depreciation expense for determining revenue requirement.*

HHHI did not present in Exhibit 2 the accounting policy change on asset reclassification from PP&E to intangible assets.

a) Has HHHI identified the accounting policy change on asset reclassification from PP&E to intangible assets? If so, please provide the accounting policy change and quantify the changes due to the adoption of IFRS for the test year and bridge year. If not, please provide the reasons and the plan when this is to be addressed.

b) For the assets identified in (a), please propose a regulatory treatment in accordance with the Board report.

Response:

a) HHHI has not identified any accounting policy changes on asset reclassification from PP&E to intangible assets. HHHI only dealt with policy that impact revenue requirement. HHHI will address the policy issue relating to intangible assets in December of 2011.

b) Computer software and land rights were included in rate base and the amortization expense in depreciation expense in determining revenue requirement.

7.

Reference: Exhibit 2 / 1 / 2, pp. 9 & 13

For underground switchgear, HHHI stated at p. 9:

Kinectrics identifies a useful life between 20 and 40 years, with a typical useful life of 30 years based on low mechanical stress and 4 electrical loading and high environmental factors. Environmental factor is high as the assets tend to rust as they sit at the side of the road, so the snow, debris, salt, etc. factor into the condition of the asset. The approximate age is 25 to 30 years; therefore HHHI has decided a useful life of 30 years is appropriate.

At p. 13 'Table 2-4: PP&E Components and Estimated Useful Life', HHHI has proposed a useful life of 20 years instead of 30 years for underground switchgear.

Please clarify the figure for the useful life of the underground switchgear that HHHI has decided is appropriate, and make any necessary changes to subsequent tables.

Response:

The useful life for the underground switchgear is 30 years. HHHI has used the 30 years in calculating 2011 and 2012 depreciation expenses. The updated table is presented below as Table OEB 1-2.

Table OEB 1-2 : Revised Table 2-4 from Application

Component	Previous Component	Existing Useful Life	Proposed Useful Life	Minimum	Typical	Maximum
Land	Land	N/A	N/A			
Overhead poles, fully dressed	Overhead Poles	25	50	40	44	50
Overhead conductors	Overhead Conductors & Devices	25	50	50	60	77
Overhead line switches, reclosures, fault circuit indicators	Overhead Conductors & Devices	25	40	30	50	60
Municipal substations – transformers incl grounding system	MS Station equipment	25	35	32	45	55
Municipal substations - DC service station incl battery & chargers	MS Station equipment	25	20	10	20	30
M.S. Switchgear	Overhead Conductors & Devices	10	40	30	40	60
Underground primary cable incl utility chambers	Underground Conductors & Devices	25	40	30	40	60
Underground secondary cable	Underground Services	25	40	40	40	60
Underground ducts and transformer switchgear foundation	Underground Conduit	25	50	30	50	80
Overhead transformers incl voltage regulator	Overhead Transformers	25	40	30	40	60
Underground transformers incl fault indicators	Underground Transformers	10	40	30	40	40
Underground switchgear and junction cubicle		-	30	20	30	40
SCADA – battery, RTU, relay, IED		15	20	15	20	30
Industrial/Commercial, wholesale Energy Meters	Interval Meters – 1 Phase, 3 Phase & Meters YE Adj	25	20	20	30	60
PTs & CTs	Meters	25	45	30	45	50
Smart meters - meters	Meters	15	15	15	15	20
Smart meters - repeaters	Meters	15	15	5	10	15
Smart meters – data concentrators	Meters	15	15	10	20	20
Office Furniture and Equipment	Office Furniture and Equipment	10	5	5	10	15
Computer Equipment Hardware	Computer Equipment Hardware	5	3	3	4	5
Computer Software	Computer Software	1	2	2	4	5
Vehicles – bucket trucks	Transportation Equipment	5	12	5	10	15
Vehicles – trailers	Transportation Equipment	5	15	5	15	20
Vehicles – vans/cars	Transportation Equipment	5	8	5	8	10
Tools, Garage Equipment, Measurement & Testing Equipment	Tools, Garage Equipment, Measurement & Testing Equipment	10	10	5	8	10
Stores Equipment	Stores Equipment	10	10	5	8	10
Wireless Communication	Communication Equipment	-	10	2	5	10

8.
Reference: Exhibit 2 / 1 / 2 / pp. 12-13

HHHI application has a life of 3 years and two years for computer hardware and software respectively. Hardware assets have had expected useful life of 5 years, and for software it has often been 3 – 5 years. Table 2-4 shows that HHHI has used a one-year period for software.

a) Please provide the basis for HHHI's proposal for 3 and 2 year useful lives.

b) For how long has HHHI used a one-year life for computer software?

Response:

a) HHHI proposed to use 3 and 2 year useful lives for computer hardware and software respectively based on the ranges in the HHHI Kinectrics report.

b) Based on the accounting records, HHHI has been using the one-year life for computer software since 2001.

9.
References: Exhibit 2 / 2 / 4 / p. 2; Exhibit 2 / 2 / 5 / p. 1

In Exhibit 2 / 2 / 5, HHHI states: "In 2009 and 2010, HHHI removed $869,000 and $367,000 respectively from accumulated depreciation for stranded meter costs as a result of the Smart Meter project." However, Table 2-19 shows variances that are much smaller than these amounts for Account 1860 - Meters.

Please provide a reconciliation between these two tables in these two exhibits.

Response:

The figures of $869,000 and $367,000 noted at line 14 of Schedule 5 should have been $126,000 and $169,108 which are presented in Tables 2-8 and 2-9.

10.
Reference: Exhibit 2 / 3 / 3 / p. 3

HHHI indicates that it is well underway toward completion of a formal Asset Management Plan.

When does HHHI expect to finalize its initial Asset Management Plan?

Response:

HHHI will continue to work on our Asset Management Plan through 2012. HHHI expects to implement the finalized Asset Management Plan early in 2013.

Gains and Losses on Retirements and Impairments

11.

Reference: Report of the Board *Transition to International Financial Reporting Standards* ("IFRS") July 28, 2009 [EB-2008-0408]

Under IFRS, asset retirement obligations include estimates of the cost of constructive obligations which was not required under CGAAP, and a revaluation of those obligations during the lives of the assets. HHHI did not present the accounting policy change on treatment of asset impairment.

The Board Report has stated as follows, at p 40:

> *Utilities shall identify separately in their rate applications the depreciation expense associated with amortizing asset retirement costs and the accretion expense associated with the amortization of the asset retirement obligations. The Board will assess these costs independently of other amortization costs to determine the portion, if any, of these costs that should be recovered in revenue requirement.*

At p. 19:

> *Where a utility for financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings the utility shall reclassify such gains and losses as depreciation expense and disclose the amount separately. Where a utility for financial reporting purposes under IFRS has reported a gain or loss on disposition of individual assets, such amounts should be identified separately in rate filings for review by the Board.*

At p. 41:

> *Where for financial reporting purposes under IFRS a utility has recorded an asset impairment loss, for rate application filings such losses shall be reclassified to PP&E and identified separately to allow consideration of whether and how such amounts are to be reflected in rates.*

a) Please confirm whether or not HHHI has any Asset Retirement Obligations ("ARO").

i. If yes, please identify and provide a detailed breakdown of the major asset components.

ii. If no, please provide a proposal for how the asset retirement obligations should be recovered in rates.

b) If HHHI has AROs, please confirm whether or not HHHI has identified the accounting change on AROs.

i. If so, please provide the accounting change and quantify the changes due to the adoption of IFRS for the test year and bridge year.

ii. If not, please provide the reasons and the plan when this is to be addressed.

c) For the AROs identified, please provide the depreciation expenses and accretion expenses and show how these expenses are currently included in the rate application.

d) Please confirm that HHHI has identified the gain or loss on the retirement of assets in a group of like assets. Please provide the treatment of the retirement for rate application purposes and disclose the amount. If the gains/losses are not charged to depreciation expense please state the reasons.

e) Please disclose any asset impairment loss recorded under IFRS which should be reclassified to PP&E. Please describe:

i. the nature of the losses;

ii. the amounts of the losses; and

iii. whether and how such amounts are to be reflected in rates.

Response:

a) HHHI does not have any known asset retirement obligations.

i. Not Applicable

ii. HHHI does not have any ARO included in the 2012 revenue requirement. In future, HHHI will seek recovery of any ARO in accordance with Board Guidelines.

b) Not applicable.

c) Not applicable.

d) Not applicable.

e) HHHI is not aware of any asset impairment loss under IFRS.

Service Reliability

12.

Reference: Exhibit 2 / 3 / 5 / pp. 2-3

The Reliability statistics in Table 2-28 for 2010 are identical, with and without consideration of loss of supply. However, Table 2-29 shows different statistics with consideration of the Hydro One system

Please explain how these tables can be reconciled; in other words why is the second part of Table 2-28 not more similar to Table 2-29, given that the latter excludes incidents that appear to be a loss of service?

Response:

Please refer to HHHI Interrogatory Response to VECC question 2.

FIT and microFIT Renewable Generation

13.

Reference: Exhibit 2 / Appendix D 'HHHI's Green Energy Plan' / pp. 6-9

Table 3.1 on page 6 of the above-noted Reference provides a Table of microFIT generators connected to HHHI's distribution system with nominal output rating of each generator. Tables 3-2-2 and 3.3 on pages 7-9 show renewable generation projects that are in the queue under the OPA's FIT or microFIT programs but are not yet connected to HHHI's distribution system.

Board staff wishes to get an update on the approval status and an indication of the expected total kilowatt ("kW") output of the generators listed in Tables 3.1 and 3-2-2.

a) Please provide an update on the approval status of the microFIT and FIT projects listed in Tables 3.2.2 and 3.3 and any new applications that are in the queue.

b) Please provide an indication of the expected total kW output of the generators listed in Table 3.1.

c) Please provide an indication of the expected total kW output of the generators listed in Tables 3-2-2 and 3.3 and any new applications that are in the queue.

Response:

a) The updated status on the approval of the microFIT and FIT projects listed in Tables 3.2.2 and 3.3 and any new applications that are in the queue are presented in the updated tables below as Table OEB 1-3 and Table OEB 1-4 respectively.

Table OEB 1-3 : Revised MicroFIT Connections Status

Table 3-2-2, microFIT Generation in OPA Queue			
Distribution Feeder Circuit	Municipal Address of Generator	Nominal Output Rating of Generator	Connected to Distribution System?
1F1	9606 32nd Sideroad	10	Not Applied
1F3	13512 Fourth Line	7.2	Not Applied
1F3	13519 Fourth Line	10	Not Applied
1F3	13821 6th Line	10	Not Applied
3F1	14106 3rd Line	5.2	Not Applied
3F1	8 Commerce Cres	10	Applied for Offer to Connect[1]
3F2	15 Karen Drive	10	Not Applied
3F2	15 willoughby way	4	Not Applied
3F3	15132 Argyll Road	10	Not Applied
5F1	12 Morgan Drive	8.4	Applied for Offer to Connect[1]
5F1	15350 Argyll Road	6	Pending
5F1	179 Confederation St	5.5	Offer to Connect Issued[2]
5F1	7210 Hwy. 7	10	Applied for Offer to Connect[1]
5F1	7280 7 Hwy, RR3	9.89	Not Applied
5F2	196 Princess Anne Drive	10	Not Applied
5F2	2 Heslop Crt	10	Offer to Connect Issued[2]
5F2	20 Donaghedy Drive	9	Not Applied
5F2	21 Dawkins Cres	10	Not Applied
5F2	7 Worden View	9	Not Applied
5F3	224 mcdonald blvd.	10	Not Applied
7F1	64 Church St.	10	Not Applied
7F2	166 Mill Street W	10	Not Applied
7F2	6 Berry Street	10	Not Applied
9F1	121 Acton Blvd	10	Not Applied
9F2	44 Eastern Avenue	10	Not Applied
9F3	278 Mill St. E.	10	Not Applied
9F3	301 Queen Street East	10	Pending
9F3	35 lasby lane	10	Offer to Connect Issued[2]
9F3	75 Roseford Terrace	10	Not Applied
11F1	11974 22nd Sideroad	9.9	Offer to Connect Issued[2]
11F1	13016 L26 C 5 5th Line	10	Pending
11F1	13705 22nd Side Rd	9.2	Offer to Connect Issued[2]
11F2	10293-4th Line	9.6	Not Applied
11F2	15 Oak Ridge Drive	10	Not Applied
11F2	31 Logan Court	10	Not Applied
11F2	333 Queen Street East	9	Pending
11F2	43 Munro Circle	10	Pending
11F2	8482 6th Line	10	Not Applied
11F3	105 Acton Blvd	10	Not Applied
11F3	12562 9th Line North	10	Pending
11f3	16632 Leslie Hill	10	Not Applied
11F3	36 Costigan Court	2.3	On Hold
11F3	39 Costigan Court	7	Offer to Connect Issued
11F3	73 Barraclough Blvd.	5	Not Applied
13F2	20 Moore Park Cres.	4.3	Offer to Connect Issued[2]
15F2	10741 Third Line	10	Not Applied
15F2	18 Credit St.	10	Not Applied
15F2	39 Harley Avenue	9	Offer to Connect Issued[2]
15F2	4 Allison Court	10	Not Applied
15F2	40 Confederation	10	Offer to Connect Issued[2]

Table OEB 1-3 : Revised MicroFIT Connections Status (cont'd)

15F2	42 Cameron Street	6.58	Not Applied
15F2	84 Confederation St.	10	Offer to Connect Issued[2]
15F2	86 River Rd.	10	Not Applied
15F3	42 Gooderham Dr	10	Offer to Connect Issued[2]
17F1	43 Alice Street	10	Not Applied
17F3	35 Marilyn Crescent	10	Not Applied
17F3	53 Hewson Crescent	8	Not Applied
19F2	1 Wilson Court	5	Not Applied
19F2	11749 22nd Sideroad	5.98	Not Applied
19F2	11760 7 Hwy	10	Not Applied
23F1	10783 6th line	9.95	Not Applied
23F1	10815 third line	10	Not Applied
23F1	10829 5TH LINE	10	Not Applied
23F1	11062 5th Line	9.975	Not Applied
23F1	11998 L20 C 1E Dublin Line	10	Not Applied
23F1	3 Deer Run Crescent	10	Offer to Connect Issued[2]
23F1	54 Arborglen Drive	10	Offer to Connect Issued[2]
23F1	59 Cobblehill Road	6	Not Applied
23F1	6 Bishop Crt	10	Not Applied
23F1	72 McNally Street	10	Not Applied
23F1	7419 Side Road 15	10	Offer to Connect Issued[2]
23F1	77 Market Street	10	On Hold
23F1	8277 10 Side Road	10	Not Applied
23F2	10739 15th Side Rd	10	On Hold
23F3	8390 Hornby Rd	10	Not Applied
41M21	13417 22 Side Rd	10	Applied for Offer to Connect[1]
41M21	13536 15 Side Road	10	Pending
41M21	13931 Cromar Ct	10	Offer to Connect Issued[2]
41M21	22 Harriet Streeet	10	Not Applied
41M21	55 Craig Crescent	7	Not Applied
41M21	82 Craig Cres	10	Pending
41M21	84 Smith Drive	10	Not Applied
41M21	8602 Winston Churchill Blvd	10	Not Applied
41M21	88 Miller Drive	9	Not Applied
41M21	8851 6th Line Road	10	Not Applied
41M21	8958 Trafalgar Road	10	Offer to Connect Issued[2]
41M21	9328 15th Sideroad	10	Not Applied
41M21	96 Poplar Ave.	10	Not Applied
41M21	98 FORSYTH CRES	7	Applied for Offer to Connect[1]
41M21	98 Main St. N	10	Not Applied
	5193 5th Line RR2	10	Not in HHH Area
41M29	9017 5th Side Road	10	Not Applied
41M29	9422 REGIONAL RD #25	10	Not Applied
41M30	12688 4th line	10	Not Applied
42M21	RR#4 11682 Hwy 25	7	Not Applied
	Expected nameplate rating output	870.975	kW

for the OPA to change the applicants application status to "Pending LDC Offer to Connect".

Connect", HHH has assessed capacity, determined capacity exists, and issued an Offer to Connect.

Table OEB 1-4: Revised FIT Connections Status

Table 3-3, FIT Generation in OPA Queue			
Distribution Feeder Circuit	**Municipal Address of Generator**	**Nominal Output Rating of Generator**	**Connected to Distribution System?**
15F1	30 Armstrong Avenue	250	Applied - Pre. CIA Phase
42M25	171 Guelph Street	375	Not Applied
41M21	8889 10th Line	250	Not Applied
	Expected nameplate rating output	875	kW

b) The expected total kW output of the generators listed is presented in the Table OEB 1-5 below.

Table OEB 1-5 : Expected Total kW Output of Generators

Updated Table 3.1 Connected and Active microFIT Generators

Distribution Circuit Feeder	Municipal Address of Generator	Nominal Output Rating of Generator	Date of Interconnection
1F3	14011 Trafalgar Road	7.2	24-Oct-11
5F1	3 Morgan Drive	10	17-Aug-10
5F1	4 Morgan Drive	10	30-May-11
5F1	8 Morgan Drive	10	22-Dec-11
5F1	9 Morgan Drive	5	26-May-10
5F1	14191 Crewsons Line	10	1-Dec-10
5F2	13066 Dublin Line	10	26-May-10
5F2	16321 6th Line, Limehouse	10	21-Dec-10
5F2	12976 Silvercreek Dirve	9.73	24-Oct-11
5-F2	181 Churchill Road South, Acton	5.4	10-Aug-11
7F1	36 Vimy Street	10	27-Jan-11
7F1	13 John Street South, Acton	10	2-Sep-11
9F3	13895 Churchill Road	10	22-Dec-10
11F1	11632 22nd Side Road	9.5	26-Aug-10
11F1	12849 5th Line	9.88	20-May-11
11F1	12909 5th Line	9.5	16-Dec-10
11F1	13111 5th Line	10	14-Oct-10
11F2	12249 8th Line	10	13-Jul-10
11F2	13010 22nd Side Road	10	26-Jul-11
11F2	41 Munro Circle	8.36	13-Jun-11
11F3	22 Bishop Court	10	3-Jun-11
11F3	14249 10th Line	9.88	25-Jul-11
15F1	48 Harding Street	3.61	8-Apr-11
15F2	7 Karen Drive	3.456	28-Jul-10
15F2	28 Logan Court	6.72	11-Apr-11
15F3	54 Hewson Cres.	5.6	8-Dec-10
17F3	9 Sherman Court	9.88	25-Oct-11
19F2	38 Chelvin Drive	3.42	4-May-11
19F2	17 Rosefield Drive	5.13	21-Jun-11
21-F1	8684 9th Line	10	1-Feb-11
23F1	7400 15 SDRD	10	5-Aug-10
23F1	9313 4th Line, RR5, Milton	9.88	15-Aug-11
23F2	11348 Trafalgar Road	8	14-Dec-10
23-F2	9365 10th Side Road	10	1-Feb-11
3-F1	40 Dairy Drive, Acton	8.6	17-Oct-11
41M21	10 Lookout Court	3.8	5-Aug-10
41M21	62 Grist Mill Drive	10	12-Jul-10
41M21	76 North Ridge Cres., Georgetown	5	31-Aug-11
41M21	9 May Street, Georgetown	2.28	19-Aug-11
41M21	63 Garrison Square	10	7-Sep-11
41M29	9722 3rd Line	10	9-Aug-10
42M25	161 Guelph Street	10	22-Dec-10
	microFIT Nameplate Rating in kW:	**349.826**	

Table 3.1.2 Connected and Active FIT Generators (New table)

Distribution Circuit Feeder	Municipal Address of Generator	Nominal Output Rating of Generator	Date of Interconnection
15F1	24 Armstrong Ave.	248	21-Jul-11
42M28	114 Armstrong Ave.	248	2-Sep-11
	FIT Nameplate Rating in kW:	**496**	

c) Please refer to the tables presented in part a) above.

HHHI's Renewable Generation Initiative

14.

References: Exhibit. 2 / Appendix D HHHI's Green Energy Plan' p. 9; Exhibit 2 / 3 / 7

HHHI indicates in its GEA Plan that in 2010 it undertook a pilot project to install pole-mounted solar photovoltaic panels at selected sites throughout its service territory.

In Exhibit 2 / 3 / 7 HHHI describes the Green Energy Initiative to install solar panels on 1400 utility poles in 2012 at a capital cost of $1.4 million proposed for inclusion in the rate base. Each installation includes a 220 - 280 watt solar panel, a Smart Energy Module with an inverter, two way wireless Smart Grid communicator, sensors, digital meter, and a pole mounting system to attach to existing utility poles. Based on the estimated total capital cost of $1.4 million, this works out to an average of $1000 per pole.

a) Please provide the results of any analysis carried out by HHHI with respect to its 2010 pilot project to install pole-mounted solar photovoltaic panels including costs, benefits, cost/benefit analysis etc.

b) Does the estimated average cost of $1000 per pole for the proposed 2012 solar panel initiative include all costs, e.g. materials, labour, engineering, commissioning, inspections etc? Please provide a breakdown of costs and explanation.

c) Is it HHHI's intention to implement the pole-mounted solar panel project within the context of other HHHI capital and operating programs?

d) What is HHHI's rationale for not considering the pole-mounted solar panel project as a capital project under the HHHI's Green Energy Plan?

Response:

a) HHHI has tested four units for the past year on poles in HHHI's service territory. These four units have operated and produced power to the secondary system at the rate of 0.78 kWh per day through all seasonal weather conditions, which is indicative of their long term performance. The units produce electricity directly to the secondary system during the peak hours during the day – producing power directly where it is consumed.

HHHI believes the benefits include line loss reduction and secondary voltage monitoring. A larger project will enable us to quantify those benefits. Further, any power production, line loss and transmission savings will be directly passed into the customer through our Deferral and Variance accounts. The qualitative benefits to the community are a highly visible renewable energy project by the utility and furthering the commitment to the Green Plan of the Municipality.

b) Yes, the budget of $1,000 includes all costs.

The units are commissioned immediately upon deployment producing electricity immediately to the secondary grid. The pole mounted solar system is comprised of a Smart Energy Module, (inverter, meter and communications), a 220 watt panel, a communicator, and a supporting rack structure for mounting onto utility poles.

c) Yes, it is HHHI's intention to implement the pole mounted solar panel project within the context of HHHI's capital.

d) HHHI did consider the project as part of the Green Energy Plan section 3.3 and at the time of writing the Green Energy Plan the full project had not been completely budgeted.

Challenges Associated with Distributed Generation

15.
Reference: Exhibit. 2 / Appendix D / pp. 10-14

HHHI describes in this reference the various "challenges" associated with connecting distributed generation to HHHI's distribution system including: impact on special protections, short circuit issues, protection coordination, impact on faulted circuit indicators and issues with shared transformer stations. These are presented as potential issues with no specific solutions, expected costs or a plan to address the issues.

What plan(s), if any, does HHHI have for addressing the potential issues described in the above-noted Reference in 2012 and beyond? Please provide details on scope, schedule, priority and costs.

Response:

For the feeder protection upgrades (described in Exhibit.2/Appendix D/pp. 10-14), HHHI is undertaking this project as part of the 2012 Capital.

For the feeder expansions, described in Exhibit 2/Appendix D/pp. 16-17, HHHI does not need to undertake such an enhancement for any of the renewable generation projects of which the organization is aware. At such time as this work may be necessary, and the costs to HHHI are deemed "material", HHHI will advise the Ontario Energy Board via an amendment to HHHI'S Green Energy Plan.

For the transformer station design provisions, described in Exhibit 2/Appendix D / on pg 17, the incremental cost (if any) will be built into the overall cost of the station.

Distribution System Enhancements for Smart Grid Development

16.
Reference: Exhibit. 2 / Appendix D / pp. 15 - 17

HHHI describes in this reference some proposed enhancements that would contribute to the Ontario government's smart grid objectives including modifications to feeder protections, extending three-phase circuitry into rural areas and consideration of distributed generation connections in the design of new transformer stations.

HHHI states that the estimated cost for the feeder protection changes is about $15,000 per feeder. It also states that, as instances arise, HHHI will extend the three-phase aerial circuitry based on a cost sharing arrangement with the generator, in accordance with the Transmission System Code. Based on that, HHHI bears the initial $90,000 per nameplate MW output of investment cost, with the balance borne by the generator.

a) Is HHHI planning to carry out the feeder protection changes on all its feeders or as needed to accommodate new generator connections? Please explain.

b) Please provide an estimate of the cost HHHI expects to incur and the timeframe for the feeder protection changes.

c) Please provide an estimate of the cost HHHI expects to incur and the timeframe for extending three-phase circuitry into rural areas.

d) Please explain HHHI's rationale for categorizing the above-noted enhancements as Smart Grid development and identify information on the Smart Grid technologies that are utilized.

e) If the estimated costs for the above-noted enhancements are not entirely Smart Grid related, please provide a breakdown that indicates the portion that is Smart Grid related and the portion that is related to connection of renewable generation.

Response:

a) HHHI has a long term project underway to modernize the feeder protections in its substations – every year or so, the feeder protections are modernized for 2 or 3 feeders. If a FIT project were to emerge on a feeder where the protections haven't yet been modernized, HHHI would simply adjust the order that we tackle the outstanding feeder protections. To reiterate, HHHI plans to modernize all vintage feeder protections anyway, so doesn't consider the possible re-ordering of work to be a special cost that should be borne by a Green Energy rate rider.

b) Expected cost for the feeder protection changes can be found in Exhibit 2 / Appendix D / pp. 16 (HHHI'S Green Energy Plan).

c) See response to question 15 above for costs. It will be several years to fully extend the three-phase circuitry into the rural areas.

d) The definition of Smart Grid in Ontario (Ontario Bill 150, Green Energy Act, 2009) specifically, Schedule B, clause 1, subsection (5) reads as follows:

Smart grid

(1.3) For the purposes of this Act, the smart grid means the advanced information exchange systems and equipment that when utilized together improve the flexibility, security, reliability, efficiency and safety of the integrated power system and distribution systems, particularly for the purposes of,

(a) enabling the increased use of renewable energy sources and technology, including generation facilities connected to the distribution system;

(b) expanding opportunities to provide demand response, price information and load control to electricity customers;

(c) accommodating the use of emerging, innovative and energy-saving technologies and system control applications; or

(d) supporting other objectives that may be prescribed by regulation.

In short, anything done to the electrical distribution system to promote the connection of renewable energy systems, or to support energy efficiency or load management control will qualify for smart grid.

HHHI'S Green Energy Plan identifies a number of distribution system enhancements that could be classified as both Smart Grid expenditures and normal asset management expenditures. HHHI has chosen to treat the modernization of feeder protections as a normal asset sustainment activity (paid for by the distribution tariff) and line extensions, if any are ever required, solely to support large-scale FIT projects as a Green Energy activity (paid for in accordance with the cited provisions of the Distribution System Code and a Green Energy rate rider).

e) Not applicable.

Cost Recovery of Green Energy Plan Costs

17.
Reference: Exhibit. 2 / Appendix D / p. 19

HHHI states in this reference that it is not seeking to recover costs related to the connection of renewable generation in the form of a short term rate rider at this time.

Please explain why HHHI has chosen not to seek cost recovery of Green Energy Act Plan costs at this time.

Response:

See response to questions 15 and 16 above – HHHI considers the modernization of our feeder protections to be a normal asset sustainment activity.

Other Distribution Revenue

18.
References: Exhibit 3 / 3 / 1; Exhibit 4 / 1 / 1 / p. 13; Exhibit 4 / 2 / 4 / p. 2-3

a) Please confirm that the revenue shown in Table 3-23 account 4375 is the same as the inter-affiliate revenue derived in Table 4-14.

b) Please identify any allocation factors in Exhibit 4 / 2 / 4 / p. 2-3 that might vary substantially from year to year. If most of the allocators are stable, please explain why the forecast of account 4375 remains stable at $396,000 at the 2011 level, rather than increasing with OM&A costs (e.g. at 31.5% per Table 4-6).

c) Is revenue from microFIT generators included in one of the accounts in Table 3-23? If so, in which account is it included and how much revenue is gained?

Response:

a) Confirmed.

b) None of the allocation factors in Exhibit 4 / 2 / 4 / p. 2-3 vary substantially from year to year to warrant an increase in the inter-affiliate revenues The increase in OM&A costs as shown in table 4 – 6 is affected mainly by the items listed below. None of which significantly affects the costs of services provided to affiliates.

- Increase in OM&A as a result of transitioning to MIFRS
- Inclusion of smart costs in OM&A in 2012
- Increase in tree trimming costs and
- Increase in FTE's as a result of succession planning.

c) The revenue from microFIT generators in not included in Table 3-23. It was not included anywhere as the amount is insignificant. The amount billed from Jan to Sept. 2011 is – $988.

Operation Maintenance and Administration

19.
References: Exhibit 4 / 1 / 1; Exhibit 4 / 2 / 1 / p. 5

In Tab 1, Tables 4-2, 4-3, 4-4, 4-5 and 4-6, HHHI provide the following with respect to Meter Reading Expenses (Account 5310):

Year	2008 Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
Meter Reading Expense	$147,000	$134,104	$134,696	$131,177	$16,300	$206,840

On page 5 of Exhibit 4 / 2 /1, HHHI states:

Meter reading services have, historically, been contracted out to a non-affiliated third party under a service contract agreement. Effective June 1, 2011 HHHI started billing Residential and General Service less than 50 kW customers on a Time-of-Use basis using smart meters.

a) Please confirm that the costs of the third party contract were recorded in account 5310 as shown in the above table.

b) Please explain the decrease in meter reading expenses in 2011 of $16,300 compared to approximately $135,000 per annum from 2008 to 2010.

c) Please explain the forecasted increase in Meter Reading Expenses for 2012, relative to:
   i. 2011; and
   ii. the historical norm of approximately $135,000 per annum.

Response:

a) The costs of the third party contract were recorded in account 5310 from 2008 Board Approved to 2010. For 2011 and 2012 the amounts of $90,000 and $25,000 respectively for third party costs were included in account 5315. For 2012, HHHI excluded $65,000 of third party costs which is for none are hydro related services.

b) Please refer to response to part a).

c)
   i) The increase in 2012 compare to 2011 is a result of the increase in smart metering costs of $190,300 that is included in 5310. (E.g. smart meter entity fees of $135,000, smart meter WAN monthly fee of $15,000, TOU Portal Maintenance fee of $16,000);

   ii) If you subtract the $190,300 smart meter related cost and add the $65,000 third party costs that was excluded in the 2012, the balance of $81,540 ($206, 840 – $190,300 + $65,000) is lower that the historical norm of $135,000.

20.
Reference: Exhibit 4 / 2 / 3 / p. 7

The increased cost of Billing and Collecting is due in part to "the addition of a Billing Clerk for succession planning purposes".

a) Please provide information on the expected length of time that there will be an overlap of the incumbent and the proposed new clerk, during the test year, and if applicable beyond the test year.

b) Assuming that the overlap is considerably less than the period of the IRM adjustments following this cost-of-service application, has HHHI considered applying an adjustment factor to the increase requested for the test year revenue requirement?

Response:

a) The expected length of time that there will be an overlap of the incumbent and the proposed new clerk, during the test year, and beyond the test year is one and a half years.

b) The overlap is less than the period of the IRM adjustments following this cost-of-service application. HHHI did not apply an adjustment factor to the increase requested for the test year revenue requirement. There are other positions in the organization that will overlap in the test year and the IRM period that HHHI did not include in the test year revenue requirement.

Specifically, an accounting clerk will retire at the end of 2012 and the payroll clerk will retire in two years. The costs relating to the overlap for none of these positions have been included in the test year.

21.
Reference: Exhibit 4 / 2 / 3 / pp. 6-7

a) Please provide further explanation of the $76,000 identified for "smart meter communication costs" as a driver for the increase of $297,106 for Account 5315 – Customer Billings.
b) Is this a recurring cost, or one-time cost in 2012 only?

Response:

a) The $76,000 included in account 5315 – Customer Billings for communication costs is the costs of communicating and reaching out to customers (see response to IR 22 for breakdown of costs).

b) It is a recurring cost.

22.

Reference: Exhibit 4 / 2 / 3 / p. 7

The increased cost of Billing and Collecting includes $76,000 in Smart Meter communication costs.

a) Please provide a description and breakdown of these costs.

b) Are there any labour or other costs that will be reduced, immediately or in the foreseeable future, that would tend to offset this increased communication cost.

Response:

a) The description and breakdown of these costs are provided in Table OEB 1-6 below.

Table OEB 1-6 : Increased Billing and Collection Cost Breakdown

Description		Amount
Newspaper ads		3,750.00
Bill inserts		24,648.00
TOU brochures		41,080.00
Town Hall Meetings		5,100.00
Community events		1,422.00
Total		**76,000.00**

b) There are no labour or other costs that HHHI can reduce immediately or in the foreseeable future, to offset this increased communication cost.

23.

References: Letter of the Board 'Use of Modified IFRS as a Basis for Filing Cost of Service Applications for 2012 Rates', March 15, 2011; Exhibit 4 / 1 / 1 / p. 1

HHHI stated in Exhibit 4 / 1 / 1, at p. 1:

> *The operating costs presented in this Exhibit represent the annual expenditures required to sustain HHHI's distribution operations. HHHI follows the Board's Accounting Procedures Handbook (the "APH") in distinguishing between operations and maintenance work. A summary of HHHI's operating costs for 2008 Board Approved, 2008 Actual, 2009 Actual, 2010 Actual, 2011 Bridge Year and the 2012 Test Year and the variances year over year, in accordance with the Filing Requirements, is presented below. HHHI has provided the required 2008 Board Approved to 2010 Actual based on CGAAP and 2011 Bridge Year and 2012 Test Year based on Modified IFRS.*

In the March 2011 letter the Board provided a revised version of paragraph 9.1.2 of the Board Report:

> *Electricity distributors filing cost of service applications for rates for 2012 should make all reasonable efforts to provide the forecasts for the 2012 test year (and any other subsequent test years) in modified IFRS accounting format. In addition, the electricity distributor must provide the required actual years, the bridge year and the forecasts for the test year(s) in CGAAP-based format. Further, the electricity distributor must identify financial differences and resulting revenue requirement impacts arising from the adoption of modified IFRS accounting. A distributor for whom the filing of the forecasts for the 2012 test year in modified IFRS is an unreasonable burden and that files under CGAAP must include in its rate application an explanation of the reason for filing under CGAAP and a plan for the transition to modified IFRS accounting as a basis for setting its rates.*

HHHI did not provide the bridge year and test years forecasts in CGAAP based format, as required by the Board.

a) Please provide all applicable schedules, e.g., operating costs, etc. for the bridge year and tests year under CGAAP similar to the ones reported under an IFRS regime

b) Please identify the financial differences and resulting revenue requirement impacts arising from the adoption of modified IFRS accounting.

Response:

a) Please see Tables OEB 1-7, OEB 1-8, OEB 1-9 and OEB 1-10.

Table OEB 1-7 : Summary of OM&A Expenses (CGAAP)

Appendix 2-E
Summary of OM&A Expenses

	LRY	2008	Variance	Percentage Change
	Board-approved	Actuals	$	%
Operations	$ -	$ 695,529	$ 695,529	
Maintenance	$ -	$ 751,353	$ 751,353	
Billing and Collecting	$ -	$ 1,012,516	$ 1,012,516	
Community Relations	$ -	$ -	$ -	
Administrative and General	$ -	$ 2,615,659	$ 2,615,659	
Total OM&A Expenses	$ -	$ 5,075,057	$ 5,075,057	
Inflation Rate				

	2008	2009	Variance	Percentage Change
	Actuals	Actuals	$	%
Operations	$ 695,529	$ 819,741	$ 124,212	17.86%
Maintenance	$ 751,353	$ 173,136	-$ 578,217	-76.96%
Billing and Collecting	$ 1,012,516	$ 1,091,868	$ 79,352	7.84%
Community Relations	$ -	$ -	$ -	
Administrative and General	$ 2,615,659	$ 2,341,417	-$ 274,242	-10.48%
Total OM&A Expenses	$ 5,075,057	$ 4,426,162	-$ 648,895	-12.79%
Inflation Rate				

	2009	2010	Variance	Percentage Change
	Actuals	Actuals	$	%
Operations	$ 819,741	$ 892,155	$ 72,414	8.83%
Maintenance	$ 173,136	$ 275,319	$ 102,183	59.02%
Billing and Collecting	$ 1,091,868	$ 1,111,430	$ 19,562	1.79%
Community Relations	$ -	$ -	$ -	
Administrative and General	$ 2,341,417	$ 2,100,978	-$ 240,439	-10.27%
Total OM&A Expenses	$ 4,426,162	$ 4,379,882	-$ 46,280	-1.05%
Inflation Rate				

Table OEB 1-7 : Summary of OM&A Expenses (CGAAP) (cont'd)

Appendix 2-E
Summary of OM&A Expenses

	2010 Actuals	2011 Bridge Year	Variance $	Percentage Change %
Operations	$ 892,155	$ 536,089	-$ 356,066	-39.91%
Maintenance	$ 275,319	$ 360,051	$ 84,731	30.78%
Billing and Collecting	$ 1,111,430	$ 1,197,615	$ 86,185	7.75%
Community Relations	$ -	$ -	$ -	
Administrative and General	$ 2,100,978	$ 2,456,346	$ 355,368	16.91%
Total OM&A Expenses	$ 4,379,882	$ 4,550,101	$ 170,219	3.89%
Inflation Rate				

	2011 Actuals	Test Year Forecast	Variance $	Percentage Change %
Operations	$ 536,089	$ 966,705	$ 430,617	80.33%
Maintenance	$ 360,051	$ 665,999	$ 305,948	84.97%
Billing and Collecting	$ 1,197,615	$ 1,683,690	$ 486,074	40.59%
Community Relations	$ -	$ -	$ -	
Administrative and General	$ 2,456,346	$ 2,687,646	$ 231,300	9.42%
Total OM&A Expenses	$ 4,550,101	$ 6,004,040	$ 1,453,939	31.95%
Inflation Rate				

	Test Year Actuals	Test Year Forecast	Variance $	Percentage Change %
Operations	$ 966,705		-$ 966,705	-100.00%
Maintenance	$ 665,999		-$ 665,999	-100.00%
Billing and Collecting	$ 1,683,690		-$ 1,683,690	-100.00%
Community Relations	$ -		$ -	
Administrative and General	$ 2,687,646		-$ 2,687,646	-100.00%
Total OM&A Expenses	$ 6,004,040	$ -	-$ 6,004,040	-100.00%
Inflation Rate				

Table 2: Additional Total OM&A Expense Comparative Information Table

Required Total OM&A Comparison

	2011 Actuals	Test Year Forecast	Variance $	Percentage Change %
Test Year versus Most Current Actuals	$ 4,550,101	$ -	-$ 4,550,101	-100.00%
	LRY Board-approved	**Test Year Forecast**	**Variance $**	**Percentage Change %**
Test Year versus LRY Board-approved	$ -	$ 6,004,040	$ 6,004,040	
Simple average of % variance for all years				-15.60%
Compound annual growth rate for all years				0

Table OEB 1-8 : Detailed OM&A Expenses (CGAAP)

Appendix 2-F
Detailed, Account by Account, OM&A Expense Table
(excluding Depreciation and Amortization)

Account Description	2008 Actual	2009 Actual	2010 Actual	Bridge Year	Test Year
Operations					
5005 Operation Supervision and Engineering	$ 181,547	$ 301,623	$ 137,107	$ 251,144	$ 261,670
5010 Load Dispatching	$ -	$ -	$ -	$ -	$ -
5012 Station Buildings and Fixtures Expense	$ 1,023	$ 57	$ 4,385	$ 4,000	$ 4,000
5014 Transformer Station Equipment - Operation Labour	$ -	$ -	$ -	$ -	$ -
5015 Transformer Station Equipment - Operation Supplies and Expenses	$ -	$ -	$ -	$ -	$ -
5016 Distribution Station Equipment - Operation Labour	$ 21,801	$ 157,120	$ 281,140	$ 15,166	$ 18,578
5017 Distribution Station Equipment - Operation Supplies and Expenses	$ 3,537	$ 18,319	$ 20,004	$ 798	$ 1,260
5020 Overhead Distribution Lines and Feeders - Operation Labour	$ 101,982	$ 146,927	$ 311,259	$ 35,556	$ 133,044
5025 Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ -	$ -	$ -	$ -	$ -
5030 Overhead Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -	$ -
5035 Overhead Distribution Transformers - Operation	$ -	$ -	$ -	$ -	$ -
5040 Underground Distribution Lines and Feeders - Operation Labour	$ -	$ -	$ -	$ -	$ -
5045 Underground Distribution Lines and Feeders - Operation Supplies and Expenses	$ 3,633	$ 8,264	$ 1,894	$ 819	$ 1,295
5050 Underground Sub-transmission Feeders - Operation	$ 159,770	$ -	$ -	$ 55,703	$ 208,434
5055 Underground Distribution Transformers - Operation	$ 78,185	$ -	$ -	$ 27,259	$ 102,000
5060 Street Lighting and Signal System Expense	$ -	$ -	$ -	$ -	$ -
5065 Meter Expense	$ 101,901	$ 102,275	$ 85,780	$ 120,136	$ 205,396
5070 Customer Premises - Operation Labour	$ 4,087	$ -	$ -	$ 927	$ 1,465
5075 Customer Premises - Operation Materials and Expenses	$ -	$ -	$ -	$ -	$ -
5085 Miscellaneous Distribution Expenses	$ 38,063	$ 85,156	$ 50,584	$ 24,582	$ 29,564
5090 Underground Distribution Lines and Feeders - Rental Paid	$ -	$ -	$ -	$ -	$ -
5095 Overhead Distribution Lines and Feeders - Rental Paid	$ -	$ -	$ -	$ -	$ -
5096 Other Rent	$ -	$ -	$ -	$ -	$ -
Total - Operations	$ 695,529	$ 819,741	$ 892,155	$ 536,089	$ 966,705
Account Description	**2008 Actual**	**2009 Actual**	**2010 Actual**	**Bridge Year**	**Test Year**
Maintenance					
5105 Maintenance Supervision and Engineering	$ 178,452	$ -	$ -	$ -	$ -
5110 Maintenance of Buildings and Fixtures - Distribution Stations	$ -	$ -	$ -	$ -	$ -
5112 Maintenance of Transformer Station Equipment	$ -	$ -	$ -	$ -	$ -
5114 Maintenance of Distribution Station Equipment	$ 120,490	$ 10,873	$ 21,018	$ 85,252	$ 104,190
5120 Maintenance of Poles, Towers and Fixtures	$ 41,005	$ 93,748	$ 149,942	$ 31,246	$ 35,112
5125 Maintenance of Overhead Conductors and Devices	$ 97,407	$ -	$ -	$ 21,963	$ 34,712
5130 Maintenance of Overhead Services	$ 96,141	$ -	$ -	$ 21,677	$ 34,261
5135 Overhead Distribution Lines and Feeders - Right of Way	$ 121,968	$ -	$ -	$ 147,501	$ 393,464
5145 Maintenance of Underground Conduit	$ 17,714	$ 11,728	$ 19,813	$ 16,994	$ 19,313
5150 Maintenance of Underground Conductors and Devices	$ 16,821	$ -	$ -	$ 3,793	$ 5,994
5155 Maintenance of Underground Services	$ 20,559	$ 27,762	$ 60,827	$ 9,636	$ 12,326
5160 Maintenance of Line Transformers	$ 35,433	$ 29,025	$ 22,493	$ 21,989	$ 26,627
5165 Maintenance of Street Lighting and Signal Systems	$ -	$ -	$ 1,227	$ -	$ -
5170 Sentinel Lights - Labour	$ -	$ -	$ -	$ -	$ -
5172 Sentinel Lights - Materials and Expenses	$ -	$ -	$ -	$ -	$ -
5175 Maintenance of Meters	$ 5,363	$ -	$ -	$ -	$ -
5178 Customer Installations Expenses - Leased Property	$ -	$ -	$ -	$ -	$ -
5195 Maintenance of Other Installations on Customer Premises	$ -	$ -	$ -	$ -	$ -
Total - Maintenance	$ 751,353	$ 173,136	$ 275,319	$ 360,051	$ 665,999

Table OEB 1-8 : Detailed OM&A Expenses (CGAAP) (cont'd)

Appendix 2-F
Detailed, Account by Account, OM&A Expense Table
(excluding Depreciation and Amortization)

Account Description	2008 Actual	2009 Actual	2010 Actual	Bridge Year	Test Year
Billing and Collecting					
5305 Supervision	$ 90,463	$ 111,360	$ 106,650	$ 65,755	$ 226,871
5310 Meter Reading Expense	$ 134,104	$ 134,696	$ 131,177	$ 16,300	$ 206,840
5315 Customer Billing	$ 332,214	$ 424,460	$ 369,933	$ 590,390	$ 680,251
5320 Collecting	$ 350,642	$ 343,066	$ 405,420	$ 421,870	$ 466,428
5325 Collecting - Cash Over and Short	$ 112	$ -	$ 6,574	$ -	$ -
5330 Collection Charges	$ 2,759	$ 3,286	$ 2,412	$ 3,300	$ 3,300
5335 Bad Debt Expense	$ 102,222	$ 75,000	$ 89,264	$ 100,000	$ 100,000
5340 Miscellaneous Customer Accounts Expenses	$ -	$ -	$ -	$ -	$ -
Total - Billing and Collecting	$ 1,012,516	$ 1,091,868	$ 1,111,430	$ 1,197,615	$ 1,683,690
Account Description	**2008 Actual**	**2009 Actual**	**2010 Actual**	**Bridge Year**	**Test Year**
Community Relations					
5405 Supervision	$ -	$ -	$ -	$ -	$ -
5410 Community Relations - Sundry	$ -	$ -	$ -	$ -	$ -
5415 Energy Conservation	$ -	$ -	$ -	$ -	$ -
5420 Community Safety Program	$ -	$ -	$ -	$ -	$ -
5425 Miscellaneous Customer Service and Informational Expenses	$ -	$ -	$ -	$ -	$ -
5505 Supervision	$ -	$ -	$ -	$ -	$ -
5510 Demonstrating and Selling Expense	$ -	$ -	$ -	$ -	$ -
5515 Advertising Expenses	$ 6,864	$ 2,032	$ -	$ -	$ -
5520 Miscellaneous Sales Expense	$ -	$ -	$ -	$ -	$ -
Total - Community Relations	$ 6,864	$ 2,032	$ -	$ -	$ -
Account Description	**2008 Actual**	**2009 Actual**	**2010 Actual**	**Bridge Year**	**Test Year**
Administrative and General Expenses					
5605 Executive Salaries and Expenses	$ 635,320	$ 855,873	$ 822,658	$ 624,277	$ 642,187
5610 Management Salaries and Expenses	$ 351,057	$ 27,061	$ 26,498	$ 331,142	$ 352,870
5615 General Administrative Salaries and Expenses	$ 463,306	$ 546,540	$ 540,503	$ 815,200	$ 957,459
5620 Office Supplies and Expenses	$ 35,696	$ 35,277	$ 40,102	$ 66,700	$ 60,850
5625 Administrative Expense Transferred - Credit	$ -	$ -	$ -	$ -	$ -
5630 Outside Services Employed	$ 293,492	$ 163,690	$ 123,089	$ 54,000	$ 117,000
5635 Property Insurance	$ 46,573	$ -	$ 7,418	$ 155,000	$ 132,000
5640 Injuries and Damages	$ 48,151	$ 33,608	$ 4,515	$ -	$ -
5645 Employee Pensions and Benefits	$ 28,192	-$ 2,271	$ -	$ -	$ -
5650 Franchise Requirements	$ -	$ -	$ -	$ -	$ -
5655 Regulatory Expenses	$ 140,190	$ 61,795	$ 69,780	$ 124,447	$ 125,000
5660 General Advertising Expenses	$ 7,507	$ 4,172	$ 7,769	$ -	$ -
5665 Miscellaneous General Expenses	$ 77,890	$ 92,642	$ 78,826	$ 1,500	$ 3,000
5670 Rent	$ -	$ -	$ -	$ -	$ -
5675 Maintenance of General Plant	$ 488,285	$ 523,030	$ 379,820	$ 284,080	$ 297,280
5680 Electrical Safety Authority Fees	$ -	$ -	$ -	$ -	$ -
5685 Independent Electricity System Operator Fees and Penalties	$ -	$ -	$ -	$ -	$ -
5695 OM&A Contra Account	$ -	$ -	$ -	$ -	$ -
6205 Donations (Charitable Contributions)	$ 29,137	$ 8,232	$ 6,489	$ 30,000	$ 30,000
Total - Administrative and General Expenses	$ 2,644,796	$ 2,349,649	$ 2,107,467	$ 2,486,346	$ 2,717,646
Total OM&A	$ 5,111,058	$ 4,436,426	$ 4,386,371	$ 4,580,101	$ 6,034,040

Table OEB 1-9 : 2011 Fixed Asset Continuity Schedule (CGAAP)

Appendix 2-B
Fixed Asset Continuity Schedule - CGAAP

2011

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land		$ 359,609	$ -	$ -	$ 359,609	$ -	$ -	$ -	$ -	$ 359,609
47	1808	Buildings		$ 3,080,205	$ -	$ -	$ 3,080,205	-$ 598,689	-$ 123,208	$ -	-$ 721,897	$ 2,358,309
13	1810	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 4,223,477	$ 111,529	$ -	$ 4,335,006	-$ 1,053,166	-$ 171,170	$ -	-$ 1,224,336	$ 3,110,670
47	1825	Storage Battery Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 15,977,374	$ 1,413,682	$ -	$ 17,391,056	-$ 12,306,771	-$ 667,369	$ -	-$ 12,974,139	$ 4,416,917
47	1835	Overhead Conductors & Devices		$ 5,607,599	$ 1,753,243	$ -	$ 7,360,842	-$ 357,649	-$ 259,369	$ -	-$ 617,017	$ 6,743,825
47	1840	Underground Conduit		$ 970,085	$ 410,570	$ -	$ 1,380,654	-$ 78,395	-$ 47,015	$ -	-$ 125,410	$ 1,255,244
47	1845	Underground Conductors & Devices		$ 4,675,723	$ 384,202	$ -	$ 5,059,925	-$ 226,091	-$ 194,713	$ -	-$ 420,804	$ 4,639,121
47	1850	Line Transformers		$ 6,961,088	$ 277,660	$ -	$ 7,238,748	-$ 327,424	-$ 283,997	$ -	-$ 611,421	$ 6,627,327
47	1855	Services (Overhead & Underground)		$ 2,556,444	$ 193,736	$ -	$ 2,750,180	-$ 418,500	-$ 106,132	$ -	-$ 524,633	$ 2,225,548
47	1860	Meters		$ 1,048,410	$ -	$ -	$ 1,048,410	-$ 19,920	-$ 41,936	$ -	-$ 61,856	$ 986,554
47	1860	Meters (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1906	Land Rights		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures		$ -	$ 146,075	$ -	$ 146,075	$ -	-$ 2,922	$ -	-$ 2,922	$ 143,154
13	1910	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ -		$ -	$ -	$ -		$ -	$ -	$ -
8	1915	Office Furniture & Equipment (5 years)		$ 351,062	$ 61,720	$ -	$ 412,782	-$ 256,806	-$ 76,384	$ -	-$ 333,191	$ 79,592
10	1920	Computer Equipment - Hardware		$ 1,033,364	$ 39,000	$ -	$ 1,072,364	-$ 967,411	-$ 210,573	$ -	-$ 1,177,984	-$ 105,620
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -		$ -	$ -	$ -		$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -		$ -	$ -	$ -		$ -	$ -	$ -
12	1925	Computer Software		$ 1,062,621	$ 172,060	$ -	$ 1,234,681	-$ 1,032,946	-$ 382,884	$ -	-$ 1,415,829	-$ 181,149
10	1930	Transportation Equipment		$ 2,291,028	$ 228,000	$ -	$ 2,519,028	-$ 1,321,349	-$ 300,629	$ -	-$ 1,621,977	$ 897,051
8	1935	Stores Equipment		$ 53,152	$ 33,320	$ -	$ 86,472	-$ 52,043	-$ 6,981	$ -	-$ 59,024	$ 27,448
8	1940	Tools, Shop & Garage Equipment		$ 558,091	$ -	$ -	$ 558,091	-$ 354,902	-$ 55,809	$ -	-$ 410,711	$ 147,381
8	1945	Measurement & Testing Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment		$ -	$ 80,755	$ -	$ 80,755	$ -	$ -	$ -	$ -	$ 80,755
8	1955	Communication Equipment (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment		$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises		$ 563,902	$ -	$ -	$ 563,902	-$ 298,141	-$ 56,390	$ -	-$ 354,531	$ 209,371
47	1980	System Supervisor Equipment		$ 833,241	$ 53,252	$ -	$ 886,494	-$ 363,824	-$ 57,324	$ -	-$ 421,149	$ 465,345
47	1985	Miscellaneous Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants		-$ 5,912,892	-$ 591,281	$ -	-$ 6,504,174	$ 1,022,032	$ 248,341	$ -	$ 1,270,373	-$ 5,233,800
	etc.			$ -		$ -	$ -	$ -		$ -	$ -	$ -
				$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -
		Total		**$ 46,293,583**	**$ 4,767,523**	**$ -**	**$ 51,061,106**	**-$ 19,011,994**	**-$ 2,796,463**	**$ -**	**-$ 21,808,457**	**$ 29,252,649**
				-$ 0								

10		Transportation
8		Stores Equipment

Less: Fully Allocated Depreciation	
Transportation	-$ 300,629
Stores Equipment	
Net Depreciation	-$ 2,495,835

Table OEB 1-10 : 2012 Fixed Asset Continuity Schedule (CGAAP)

Appendix 2-B
Fixed Asset Continuity Schedule - CGAAP

2012

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land		$ 359,609			$ 359,609	$ -	$ -		$ -	$ 359,609
47	1808	Buildings		$ 3,080,205			$ 3,080,205	-$ 721,897	-$ 123,208		-$ 845,105	$ 2,235,100
13	1810	Leasehold Improvements		$ -			$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -	$ -		$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 4,335,006	$ 34,861		$ 4,369,867	-$ 1,224,336	-$ 174,097		-$ 1,398,433	$ 2,971,434
47	1825	Storage Battery Equipment		$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 17,391,056	$ 4,057,518		$ 21,448,574	-$ 12,974,139	-$ 783,799		-$ 13,757,938	$ 7,690,636
47	1835	Overhead Conductors & Devices		$ 7,360,842	$ 2,504,129		$ 9,864,971	-$ 617,017	-$ 344,516		-$ 961,534	$ 8,903,437
47	1840	Underground Conduit		$ 1,380,654	$ 493,240		$ 1,873,894	-$ 125,410	-$ 65,091		-$ 190,501	$ 1,683,393
47	1845	Underground Conductors & Devices		$ 5,059,925	$ 413,691		$ 5,473,616	-$ 420,804	-$ 210,671		-$ 631,475	$ 4,842,141
47	1850	Line Transformers		$ 7,238,748	$ 528,576		$ 7,767,324	-$ 611,421	-$ 300,121		-$ 911,542	$ 6,855,781
47	1855	Services (Overhead & Underground)		$ 2,750,180	$ -		$ 2,750,180	-$ 524,633	-$ 110,007		-$ 634,640	$ 2,115,540
47	1860	Meters		$ 1,048,410	$ -		$ 1,048,410	-$ 61,856	-$ 41,936		-$ 103,792	$ 944,617
47	1860	Meters (Smart Meters)		$ 3,768,873	$ -		$ 3,768,873	-$ 501,430	-$ 251,625		-$ 753,055	$ 3,015,818
N/A	1905	Land		$ -	$ -		$ -	$ -	$ -		$ -	$ -
CEC	1906	Land Rights		$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures		$ 146,075	$ 10,000		$ 156,075	-$ 2,922	-$ 6,043		-$ 8,965	$ 147,111
13	1910	Leasehold Improvements		$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (5 years)		$ 412,782	$ 300		$ 413,082	-$ 333,191	-$ 82,586		-$ 415,777	-$ 2,695
10	1920	Computer Equipment - Hardware		$ 1,072,364	$ 213,224		$ 1,285,588	-$ 1,177,984	-$ 235,795		-$ 1,413,780	-$ 128,191
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
12	1925	Computer Software		$ 1,234,681	$ 363,000		$ 1,597,681	-$ 1,415,829	-$ 283,236		-$ 1,699,065	-$ 101,385
10	1930	Transportation Equipment		$ 2,519,028	$ 230,000		$ 2,749,028	-$ 1,621,977	-$ 329,254		-$ 1,951,231	$ 797,797
8	1935	Stores Equipment		$ 86,472	$ -		$ 86,472	-$ 59,024	-$ 8,647		-$ 67,672	$ 18,800
8	1940	Tools, Shop & Garage Equipment		$ 558,091	$ 43,170		$ 601,261	-$ 410,711	-$ 57,968		-$ 468,678	$ 132,583
8	1945	Measurement & Testing Equipment		$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1950	Power Operated Equipment		$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment		$ 80,755	$ -		$ 80,755	$ -	$ -		$ -	$ 80,755
8	1955	Communication Equipment (Smart Meters)		$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment		$ -	$ -		$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises		$ 563,902	$ -		$ 563,902	-$ 354,531	-$ 56,390		-$ 410,921	$ 152,981
47	1980	System Supervisor Equipment		$ 886,494	$ 53,252		$ 939,746	-$ 421,149	-$ 60,875		-$ 482,023	$ 457,722
47	1985	Miscellaneous Fixed Assets		$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants		-$ 6,504,174	-$ 1,396,208		-$ 7,900,382	$ 1,270,373	$ 288,091		$ 1,558,464	-$ 6,341,917
	etc.			$ -			$ -	$ -			$ -	$ -
								$ -			$ -	$ -
		Total		**$ 54,829,979**	**$ 7,548,752**	**$ -**	**$ 62,378,731**	**-$ 22,309,887**	**-$ 3,237,776**	**$ -**	**-$ 25,547,663**	**$ 36,831,068**

10		Transportation
8		Stores Equipment

Less: Fully Allocated Depreciation	
Transportation	-$ 329,254
Stores Equipment	
Net Depreciation	-$ 2,908,522

b) Please refer to HHHI interrogatory response to Energy Probe question 6.

24.

References: Report of the Board *'Transition to International Financial Reporting Standards'* ("IFRS") July 28, 2009 [EB-2008-0408]; Exhibit 4 / 2 / 7 / p. 1

HHHI stated:

> *HHHI uses the pooling of assets for all fixed assets with the exception of Computer Equipment/Software, Automotive Equipment, Furniture & Equipment, Communication Equipment, and Capital Tools.*

Useful lives for PP&E are to be reviewed at least at each financial year-end with MIFRS.

The Board's policy articulates that LDCs shall use the Board sponsored Kinectrics study or sponsor their own study to justify changes in useful lives. The typical useful lives

(TUL) from the Kinectrics report is the recommended Reference point. The Board will no longer prescribe service lives for PP&E.

Salient points from the Board Report are as follows, at p. 21:

> *The Board will facilitate a joint depreciation study for electrical distribution utilities. The aim of the study will be to determine depreciation methodologies and rates that will be applied to all electrical distribution utilities for the purpose of setting rates and regulatory reporting. The study must give due weight to the IFRS requirements regarding depreciation, including componentization.*
>
> *The Kinectrics Report provides information that the Board expects distributors will consider as they develop asset service lives suitable in their particular circumstances. The Board expects distributors to reflect their consideration of the information contained in the Kinectrics Report when they present an IFRS-based rates application to the Board.*

For the bridge and test years, please confirm if HHHI :

a) used componentization for the underlying PP&E assets, including gross capital costs and accumulated depreciation values and not pooling of assets (i.e. pool assets is not permitted)
b) depreciated separately the significant parts or components of each item of PP&E.
c) used the revised useful lives, and calculated the depreciation expense based on revised service lives. In addition, please provide the calculation required.

d) if the answer in “c” above is “no”, please explain and provide the changes in depreciation expenses and accumulated depreciation for the bridge and test years.

Response:

a) It is confirmed that HHHI used componentization for the underlying PP&E assets, including gross capital costs and accumulated depreciation values and not pooling of assets.

b) It is confirmed that HHHI depreciated separately the significant parts or components of each item of PP&E.

c) It is confirmed that HHHI used the revised useful lives, and calculated the depreciation expense based on revised service lives. The depreciation expense for 2011 and 2012 based on the revised useful lives are presented in Exhibit 4, Tab, Schedule 7, Tables 4- 22 and 4 – 23.

d) Not Applicable.

Low Income Energy Assistance Program (LEAP)

25.
References: Exhibit 3 / 1 / 1 / p. 1; Exhibit 4 / 2 / 3 / p. 9

The Board's Filing Requirements, dated June 22, 2011, section 2.7.2.3 state that a distributor should commit 0.12% of its distribution revenue requirement to emergency financial assistance, and clarifies that the revenue requirement is the forecasted service revenue requirement. HHHI has identified its service revenue requirement as $11,237,701 at the Reference in Exhibit 3. However, the revenue requirement used by HHHI is $10,714,114 and the LEAP provision is rounded up to $13,000.

a) Please provide an alternative calculation based on the service revenue requirement described in Exhibit 3.
b) Please state whether or not HHHI has included an amount in its 2012 Test year revenue requirement for any legacy program(s), such as Winter Warmth. If so, please identify the amount and provide a breakdown identifying the cost of each program along with a description of each program.

Response:

a) The alternative calculation based on the service revenue requirement described in Exhibit 3 is presented in below in Table OEB 1-11.

Table OEB 1-11 : Revised LEAP Funding Requirement

LEAP Funding Requirement		Amount
2012 Service Revenue Requirement		11,237,701
LEAP Funding - %		0.12%
LEAP Funding Amount		**13,485**

b) HHHI did not include any amount in its 2012 Test year revenue requirement for any legacy program(s), such as Winter Warmth.

Charitable Donations

26.
References: Exhibit 4 / 2 / 2 / p. 2; Exhibit 4 / 2 / 3 / pp. 2 & 9

a) Please describe the forecasted charitable donations in detail, in particular whether they are designed to provide assistance to HHHI's customers for purposes described in the Board's Filing Requirements, June 22, 2011,section 2.7.2.5.

b) Please explain why HHHI's annual donations have fluctuated since 2008 over a range from less than $7000 up to nearly $30,000, and why the forecasted amount is at the top of this range.

c) Charitable donations are shown as $0 in the 2010 PILs return (Exhibit 4 / Appendix D) and in the test year PILs spreadsheet filed with HHHI's pre-filed evidence, but are shown as $6489 and $30,000 respectively in Table 4-9. Should these entries be the same in both places, and if so which are the right numbers?

d) Table 4-10 (Exhibit 4 / 2 / 3 / p. 2) shows a $20,905 reduction in charitable donations as a cost driver, which is apparently inconsistent with the request for approval of $30,000. Please explain or correct this inconsistency.

Response:

a) The forecasted charitable donation of $30,000 is for donations to community organizations. The amount does not include any contributions to provide assistance to the distributor customers in paying their electricity bills and assistance to low income customers as per section 2.7.25 of the Filing Requirements.

HHHI did not include the charitable donations in the 2012 revenue requirement.

b) Please see response to part a above.

c) The entries should be the same in both places. For 2010, the amount should be $0 and for 2012 should be $30,000.

d) Please see response to part a above.

Provision for PILs

27.

References: Excel file Test Year Income Tax, Sheet T 'PILs,Tax Provision'; Exhibit 4/3/1

a) Please confirm that the capital tax rate applicable to Capital Tax in 2010 in Table 4-24 should be 0.075%, i.e. half of 0.15%, rather than 0.75% as shown.

b) The tax rate assumed in the pre-filed Excel spreadsheet (item M in worksheet T) is 15.5%. The rate used in Table 4-24 in Exhibit 4 is 26.5%. Please reconcile these assumptions and/or provide an explanation of this apparent inconsistency.

c) Grossed-up PILs in the pre-filed Excel spreadsheet (item U in worksheet T) is $67,791. Income Tax in Table 4-24 in Exhibit 4 is $131,542. Please reconcile these assumptions and/or provide an explanation of this apparent inconsistency.

Response:

a) It is confirm that the capital tax rate applicable to Capital Tax in 2010 in Table 4-24 should be 0.075%, i.e. half of 0.15%, rather than 0.75% as shown.

b) The tax rate in the pre-filed Excel spreadsheet (item M in worksheet T) of 15.5% is a calculate rate from the Board's model. Because HHHI taxable income is less than $500,000, the model used the small business rate of (Federal 11% + Ontario 4.5%). HHHI used the combined rate of 26.5%.

c) The tax calculated on the Board's Model is based on the small business rates as explained part b) above. Thus resulting in a lower tax before and after gross up when compare to amounts shown in table 2 -24.

Smart Meter Entity

28.

References: Exhibit 4 / 2 / 3 / p. 6; Board Decision, Powerstream [EB-2010-0209], p. 14

HHHI has included a forecast cost of $135,000 for its cost from a fee from the IESO for the Smart Meter Entity.

a) Please describe the assumptions made by HHHI in formulating this amount.

b) Was HHHI aware of the referenced Board Decision denying Powerstream's request to cover a forecast MDM/R cost forecast on the basis that it was premature, at least until such time as the Board approves an IESO fee for the service?

Response:

a) HHHI derived the Smart Meter Entity Fee of $135,000 by using the following methodology:

(20,500 customers x $0.55 per month x 12 months).

b) HHHI recently became aware of the Board Decision denying Powerstream's request to cover a forecast MDM/R cost forecast on the basis that it was premature. HHHI will remove it MDM/R cost $135,000 for its 2012 revenue requirement but request that Board allow for any such amount to capture in a deferral account to be recovered in the future.

Inflation Rate

29.

Reference: Exhibit 4 / 1 / 1 / p. 2

With Reference to the Statistics Canada source cited in the footnote to Table 4-1, it is not clear how the inflation index used by HHHI was derived from that source. Please provide additional information on the inflation index of 1.0%, used to prepare HHHI's test year forecast of expenditures.

Please explain

a) whether the index was applied for 12 months or only 6 months,
b) whether the index included all consumer-good categories or did it exclude some categories,
c) whether the index was seasonally adjusted.

Response:

a) The inflation index of 1.0%, cited in the footnote of Table 4-1 should not have been included in the table.

b) Please refer to part a).

c) Please refer to part a).

Affiliate Transactions

30.

Reference: Exhibit 4 / 2 / 5 / p. 2; Exhibit 4 / Appendix B

Table 4-15 is titled **"**Purchases of Services from Non-Affiliate Suppliers". The preamble of each of the Service Agreements filed in Appendix B provides for the affiliate to "provide various services" to HHHI.

Please confirm that the revenue requirement does not include a component of cost of any such services; otherwise please provide a table similar to Table 4-15 for the costs of services from affiliate suppliers.

Response:

HHHI confirms that the revenue requirement does not include any component of costs for services from affiliate suppliers.

Depreciation

31.

Reference: Exhibit 4 / 2 / 7 / p. 6

a) Total Depreciation in Table 4-23 is $1,834,363, and depreciation in the RRWF 'Revenue Requirement' is $1,624,165. Which amount is correct?

b) Several accounts do not have an asset life entered in column 'f' of Table 4-23, and the corresponding depreciation rate in column 'g' is also blank. Please provide the missing data, or an explanation of why it is missing.

c) Some of the accounts have no depreciation expense in column 'h', despite having a net fixed asset balance in column 'e', for example Account 1955. Please provide amounts for column 'h' if there should be an amount, or an explanation of why it should be blank.

d) Some accounts have depreciation amounts in column 'h' that do not appear to be based on the formula, for example Account 1915. Please provide an explanation of how the formula was used or an explanation of when it is to be over-ridden.

Response:

a) The depreciation in Table 4-23 of $1,834,363 is the total depreciation. The depreciation in the RRWF 'Revenue Requirement' of $1,624,165 is total depreciation less depreciation for transportation equipment ($1,834,363 – $210,198) which included in burdens.

b) Table OEB 1-12 below is an updated Table 4-23. Also, please refer to HHHI interrogatory response to Energy Probe question 31 part a.

Table OEB 1-12 : Revised Table 4-23 from Application

Account	Description	Opening Balance (a)	Less Fully Depreciated[1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [2]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	Did Depreciation Rate in "g" Change (Yes/No)? [3]
1805	Land	$ 359,609		$ 359,609	$ -	$ 359,609			$ -	Yes
1808	Buildings	$ 3,080,205		$ 3,080,205	$ -	$ 3,080,205	42	2%	$ 82,064	Yes
1810	Leasehold Improvements	$ -		$ -	$ -	$ -			$ -	Yes
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -	$ -			$ -	Yes
1820	Distribution Station Equipment <50 kV	$ 4,318,466		$ 4,318,466	$ 54,745	$ 4,345,839	40	3%	$ 152,917	Yes
1825	Storage Battery Equipment	$ -		$ -	$ -	$ -			$ -	Yes
1830	Poles, Towers & Fixtures	$ 17,274,087		$ 17,274,087	$ 3,960,619	$ 19,254,396	50	2%	$ 343,098	Yes
1835	Overhead Conductors & Devices	$ 7,245,498		$ 7,245,498	$ 2,397,685	$ 8,444,340	50	2%	$ 126,334	Yes
1840	Underground Conduit	$ 1,373,099		$ 1,373,099	$ 466,069	$ 1,606,134	50	2%	$ 28,062	Yes
1845	Underground Conductors & Devices	$ 5,050,704		$ 5,050,704	$ 389,624	$ 5,245,516	30	3%	$ 88,643	Yes
1850	Line Transformers	$ 7,223,017		$ 7,223,017	$ 514,137	$ 7,480,085	40	3%	$ 128,283	Yes
1855	Services (Overhead and Underground)	$ 2,750,180		$ 2,750,180	$ -	$ 2,750,180	40	3%	$ 60,785	Yes
1860	Meters	$ 1,048,410		$ 1,048,410	$ -	$ 1,048,410	20	5%	$ 27,901	Yes
1860	Meters (Smart Meters)	$ 3,768,873		$ 3,768,873	$ -	$ 3,768,873	15	7%	$ 251,625	Yes
1905	Land	$ -		$ -	$ -	$ -			$ -	Yes
1906	Land Rights	$ -		$ -	$ -	$ -			$ -	Yes
1908	Buildings & Fixtures	$ 146,075		$ 146,075	$ 10,000	$ 151,075	42	2%	$ -	Yes
1910	Leasehold Improvements	$ -		$ -	$ -	$ -			$ -	Yes
1915	Office Furniture & Equipment (10 Years)	$ -		$ -	$ -	$ -			$ -	Yes
1915	Office Furniture & Equipment (5 Years)	$ 412,782		$ 412,782	$ 300	$ 412,932	5	20%	$ 19,736	Yes
1920	Computer Equipment - Hardware	$ 1,072,364		$ 1,072,364	$ 180,000	$ 1,162,364	3	33%	$ 134,832	Yes
1920	Computer Equip. - Hardware (Post Mar. 22/04)	$ -		$ -	$ -	$ -			$ -	Yes
1920	Computer Equip. - Hardware (Post Mar. 19/07)	$ -		$ -	$ -	$ -			$ -	Yes
1925	Computer Software	$ 1,218,701		$ 1,218,701	$ 363,000	$ 1,400,201	2	50%	$ 155,699	Yes
1930	Transportation Equipment	$ 2,519,028		$ 2,519,028	$ 230,000	$ 2,634,028	8	13%	$ 210,198	Yes
1935	Stores Equipment	$ 86,472		$ 86,472	$ -	$ 86,472	10	10%	$ 3,546	Yes
1940	Tools, Shop & Garage Equipment	$ 558,091		$ 558,091	$ 43,170	$ 579,676	10	10%	$ 52,314	Yes
1945	Measurement & Testing Equipment	$ -		$ -	$ -	$ -			$ -	Yes
1950	Power Operated Equipment	$ -		$ -	$ -	$ -			$ -	Yes
1955	Communications Equipment	$ 75,194		$ 75,194	$ -	$ 75,194	50	2%	$ -	Yes
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -			$ -	Yes
1960	Miscellaneous Equipment	$ -		$ -	$ -	$ -			$ -	Yes
1975	Load Management Controls Utility Premises	$ 563,902		$ 563,902	$ -	$ 563,902	40	3%	$ 12,037	Yes
1980	System Supervisor Equipment	$ 885,854		$ 885,854	$ 52,613	$ 912,161	20	5%	$ 46,844	Yes
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -			$ -	Yes
1995	Contributions & Grants	-$ 6,473,408		-$ 6,473,408	-$ 1,284,968	-$ 7,115,892	50	2%	-$ 90,557	Yes
etc.		$ -		$ -	$ -	$ -			$ -	Yes
		$ -		$ -	$ -	$ -			$ -	Yes
	Total	$ 54,557,203	$ -	$ 54,557,203	$ 7,376,995	$ 58,245,701			$ 1,834,363	

c) Please refer to HHHI interrogatory response to Energy Probe question 38 part a.

d) Please refer to HHHI interrogatory response to Energy Probe question 38 part c.

Ontario Municipal Employees Retirement System Pension Costs

32.

Reference: Exhibit 4 / 2 / 6

HHHI has submitted in the reference, at p. 5, that it has

> *"anticipated an increase in OMERS pension costs regarding a 3-year, 1% per year increase in OMERS premiums beginning in 2011. OMERS estimates the 1% contribution rate increase in 2011 would increase the amount an employer contributes to OMERS by about 10-13%"*

HHHI has also provided Tables 4-16, 4-17 and 4-18 showing Compensation and Benefits, OMERS Pension Premiums, and Employee Future Benefits respectively.

Please explain how HHHI made its forecast of OMERS premiums in the test year (which is an increase of $160,000 or approximately 75% more than 2010 actual in Table 4-17), and relate this to the increase in its forecast of salary and wages (which is approximately 20% more than 2010 actual).

Response:

The Budget model calculates OMERS Premiums based on 8.3% on the first $48,300 of Contributory Earnings and 12.8% on the balance.

Treatment of Pensions and Other Post-Employment Benefits

33.

References: Exhibit 4 / 2 / 6 / p. 6 ; Exhibit 4 / Appendix C 'Report on the Actuarial Valuation of Post-Retirement Non-Pension Benefits'

The cover sheet of the report filed as Appendix C notes that it is a draft version dated March 23, 2010.

a) Has the report been finalized in the meantime? Is there a signed version of p. 19? If not, why not?

b) If the report has been finalized, please provide any changes that were made to the draft that HHHI has filed.

c) If the actuarial report is used in formulating the information in Table 4-18, "Employee Future Benefits", please indicate which results in the report are linked to HHHI's actual or forecasted information in Table 4-18.

Response:

a) Yes, the report is finalized. Please refer to Appendix OEB 1-C.

b) HHHI confirms no changes were made to the draft that was filed.

c) Please refer to Appendix OEB 1-C.

34.

References: IASB revisions to IAS 19, Employee Benefits, June 2011; Exhibit 4 / Appendix C 'Report on the Actuarial Valuation of Post-Retirement Non-Pension Benefits'

The IAS revisions are effective January 1, 2013, but early adoption is permitted. These revisions include the elimination of the option to defer recognition of gains and losses, known as the "corridor method".

a) Please confirm if HHHI has unamortized actuarial gains and losses and past service costs at the date of transition (January 1, 2011).

b) If yes, what is the accounting treatment of the unamortized actuarial gains and losses and past service costs at the date of transition (January 1, 2011)?

c) What is the proposed regulatory treatment of these amounts – are these amounts incorporated into the revenue requirement? Please explain.

d) Please confirm whether or not HHHI has adopted the revisions to IAS 19, Employee Benefits, and state whether the impacts of this early adoption are incorporated in the revenue requirement.

Response:

a) HHHI confirms that it has unamortized actuarial gain and past service costs at the date of transition. Please refer to Appendix OEB 1-D.

b) The unamortized gains and losses were not recorded at the date of transition.

c) The unamortized gains/losses were included in revenue requirement to the extent of the amortization of these amounts over estimated benefit expense and accrued benefit obligation.

d) HHHI has not early adopted the changes in IAS 19 and so there has been no change in revenue requirement compared to the audited F/S under CGAAP.

Cost of Capital

35.
Reference: Exhibit 5 / 1 / 1

a) Please provide a copy of the Promissory Note that is held by the Town of Halton Hills.

b) Have there been any changes to the note since it was first issued? If so please explain, and provide copies of the amendments.

c) Does the note have a fixed rate or is it variable or re-negotiated periodically? Please explain.

d) Please reconcile the information in Tables 5-2 through 5, which show a rate of 6.00%, with Table 5-7 which shows a rate of 6.25%.

Response:

a) Please refer to Appendix OEB 1-B.

b) There have been no changes to the principle amount of the Promissory Note.

c) The rate of interest is prescribed, from time to time, by the Treasurer of the Corporation of the Town of Halton Hills in accordance with the provisions of By-laws No. 00-100 and 01-130 of the Corporation of the Town of Halton Hills.

d) Table 5-2 through table 5-5 reflect the OEB approved 2008 Cost of Service Long – Term rate of 6.0%. Table 5-7 reflects the actual rate of 6.25% paid on the Long – Term Debt.

Cost Allocation

36.
Reference: Exhibit 7 / 1 / 1 / p. 2; Board Report "Review of Electricity Distribution Cost Allocation Policy", March 31, 2011 [EB-2010-0219]

The Board Report states, at p. 26

> *The Board is of the view that default weighting factors should be utilized only in exceptional circumstances….. [A]ny distributor that proposes to use those default values will be required to demonstrate that they are appropriate given their specific circumstances.*

Has HHHI adopted the default weighting factors as appropriate for itself. If so, please provide documentation as specified in the Board's Report. Alternatively, please provide descriptions and weighting factors for Services and Billing Costs, and a calculation of the impact on the respective class revenues.

Response:

The cost allocation study has been updated to reflect weighting factor specific to HHHI. The results of using the specific weighting factors are provided in the updated cost allocation study.

The updated cost allocation model will be filed as part of the response to the interrogatories.

37.

Reference: Exhibit 7 / Appendix A and B

Exhibit 7 / Appendix B consists of several worksheets from an alternative run of the cost allocation model, which appear to differ from the worksheets in Appendix A only with respect to Miscellaneous Revenue, with the total in Appendix B being larger by $50,000.

a) Please confirm that this is the only difference, and that the version in Appendix A is consistent with the remainder of the application.

b) Please explain which revenue account(s) differ between the two versions, and what assumptions have been made underlying both versions of the cost allocation model.

Response:

a) It is confirmed that this is the only difference, and that the version in Appendix A is consistent with the remainder of the application.

b) The revenue that differs between the two versions is 4210- Rent from Electric Property. As indicated in response to question 36 above, HHHI will file an updated cost allocation model and will make the correction to the miscellaneous revenue.

38.

Reference: Exhibit 1 / 1 / 11; Board Report "Review of Electricity Distribution Cost Allocation Policy", March 31, 2011 [EB-2010-0219]

In HHHI's previous cost-of-service application the Board approved the situation in which HHHI would charge its General Service 1000-4999 kW rates to Hydro One at two delivery points (EB-2007-0696, Decision p. 18). The Decision noted that the situation was under review more generally and instructed HHHI to remain up-to-date on the matter. In this application, HHHI has stated that it is not a host distributor.

a) Does HHHI continue to provide power to Hydro One at the delivery points discussed in the previous proceeding? If not, in which year did this situation change?

b) Please confirm that there are no other similar delivery points to Hydro One or another distributor?

c) If HHHI continues to deliver power to Hydro One, does HHHI have a proposal that future treatment of Hydro One as an embedded distributor that would be consistent with changes in the Board's cost allocation policy at p. 32 of the referenced Report?

Response:

a) Yes. HHHI still provides power to Hydro One at the delivery points discussed in the previous proceeding.

b) It is confirmed that there are no other similar delivery points to Hydro One or another distributor.

c) HHHI will be making an application in 2013 to treat of Hydro One as an embedded distributor that would be consistent with changes in the Board's cost allocation policy at p. 32 of the referenced Report.

Total Loss Factor

39.
References: Exhibit 2 / Appendix C / p. 15; Exhibit 8 / 4 / 1

a) Please provide a calculation of the Total Loss Factor (“TLF”) based on the most recent three-year history, together with an explanation of why the TLF being applied for should include the relatively high losses incurred in 2006 and 2007.

b) Has HHHI considered that its voltage conversion capital projects described in Exhibit 2 may decrease line losses? If so, does it expect that any improvements would reverse the trend of increased Distribution Loss Factor (“DLF”) shown in row G, Table 8-9? If it has not considered the possibility of this favourable outcome in DLF, why not?

Response:

a) The Total Loss Factor (“TLF”) based on the most recent three-year history is presented below as Table OEB 1-13. HHHI calculated its loss factor based on the historical five years which is preferred by the OEB in accordance with section 2.11.7 of the Filing Requirements. HHHI believes that the five year average is more reflective of its losses as it would capture all of the different variables contributing the losses.

Table OEB 1-13 : Three (3) Year TLF Average

		Historical Years			3-Year Average
		2008	2009	2010	
	Losses Within Distributor's System				
A(1)	"Wholesale" kWh delivered to distributor (higher value)	507,787,443	499,800,409	520,540,577	509,376,143
A(2)	"Wholesale" kWh delivered to distributor (lower value)	491,090,370	483,365,966	503,424,156	492,626,831
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	-	-	-	-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	491,090,370	483,365,966	503,424,156	492,626,831
D	"Retail" kWh delivered by distributor	480,192,790	472,272,010	491,761,405	481,408,735
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)				-
F	Net "Retail" kWh delivered by distributor = **D - E**	480,192,790	472,272,010	491,761,405	481,408,735
G	Loss Factor in Distributor's system = **C / F**	102.27%	102.35%	102.37%	102.33%
	Losses Upstream of Distributor's System				
H	Supply Facilities Loss Factor	1.034	1.034	1.034	1.034
	Total Losses				
I	Total Loss Factor = **G x H**	105.75%	105.83%	105.85%	105.81%

b) HHHI has considered that the voltage conversion projects will decrease line losses, however, due to the large overhead, rural area makeup of HHHI, it would be difficult to assume a specific amount at this time.

Retail Transmission Service Rates

40.

Reference: Exhibit 8 / 3 / 1; RTSR Adjustment Work Form

Worksheet '8 – Forecast Wholesale' shows that HHHI's wholesale cost includes a component of about 10% being established by the IESO's Uniform Transmission Rates. HHHI's evidence is that it is totally embedded, which would seemingly imply that only Hydro One's Sub-Transmission RTSRs would establish the wholesale cost.

Please provide an explanation of this apparent inconsistency, together with any additional evidence or corrections that may be necessary.

Response:

HHHI is totally embedded to HONI in the respect that HHHI is fed entirely by HONI feeders outside of HHHI's boundaries. However, at two of the seven feeders, HHHI owns the infrastructure up to the connection points at the HONI Transformer station. The IESO bills wholesale costs on the energy from these two feeders. As such, no additional evidence or corrections to the information filed is required.

Retail Service Charges

41.

References: Exhibit 8 / 8 / 4 / p. 7; Exhibit 9 / 3 / 1 / p. 2

The balance in Account 1518 proposed for disposition in Exhibit 9 is $31,418 credit.

a) Please provide a description of the incremental costs that affect Account 1518, and a schedule of the approximate amount of incremental cost recorded in these accounts.

b) Please provide the approximate annual revenue from each of the Retailer Charges that affect Account 1518, i.e. charges for establishing a service agreement, monthly fixed and variable charges, and billing-related charges.

c) Please confirm that HHHI's accounting practices are consistent with Article 490 of the Accounting Procedures Handbook, with respect to offsetting entries of incremental cost amounts from operating accounts, for example from Account 5340 to the variance account.

d) Has HHHI considered a change to any of the retail service charges to more closely match the corresponding incremental cost?

Response:

a) The incremental costs that are recorded in Account 1518 are presented below in Table OEB 1-14.

Table OEB 1-14 : Incremental Cost Recorded in Account 1518

Incremental Retail Costs	2008	2009	2010
Total incremental labour costs related to retailer Services	11,389	8,749	10,069
Hub maintenance costs	7,313	8,390	7,851
Total	**18,702**	**17,139**	**17,920**

b) The approximate annual revenue from each of the Retailer Charges that affect Account 1518 is presented in Table OEB 1-15 below.

Table OEB 1-15 : Retailer Charge Revenue

Retailer Charges	2008	2009	2010
Retail Monthly Service Charge	3,560	3,620	3,480
Avoided Cost Credit	(52)	-	-
Montlhy Billing Charge	9,386	9,692	8,491
Retail Variable Charge	15,601	16,320	14,646
Service Agreement	200	(100)	100
	28,695	29,532	26,716

c) It is confirmed that HHHI's accounting practices are consistent with Article 490 of the Accounting Procedures Handbook, with respect to offsetting entries of incremental cost amounts from operating accounts.

d) HHHI did not consider a change to any of the retail service charges to more closely match the corresponding incremental costs that this time.

Credit Card Convenience Fee

42.

Reference: Exhibit 8 / 8 / 4 / p. 6

a) HHHI's Conditions of Service, found on its web-site, identifies at p. 23 that a convenience fee will be charged on security deposits made by credit card. Please provide an explanation for the nature of the costs being recovered by this fee.
b) HHHI's Conditions of Service identifies at p. 26 that a Board-approved fee may be charged for certain requests for aggregated customer information. Please provide an explanation for the nature of the costs being recovered by this fee.
c) Please explain whether in the applicant's view, these rates and charges should be included on the applicant's tariff sheet, for example amongst its proposed Specific Service Charges.

Response:

a) The convenience fee is charged and collected directly by the Credit Card Merchant Company providing the service on behalf of HHHI.

b) HHHI's Conditions of Service, page 26, Section 2.5, Customer Information states "Hydro may charge an OEB approved fee for all other requests for aggregated information" is in fact referring to the current Specific Service Charges as approved in the current tariff of rates

c) As per response to question 42 b) above, these rates are included in Specific Service Charges on HHHI's Tariff sheet.

Deferral and Variance Accounts

43.

Reference: Exhibit 9, Tab 2, Schedule 1, Page 13; Exhibit 9, Appendix B-DVA Continuity Schedule Work Form; Chapter 2 of Filing Requirements

The Provincial Sales Tax ("PST") and the Federal Goods and Services Tax were harmonized into the Harmonized Sales Tax ("HST") effective July 1, 2010. As a result of this harmonization, applicants may benefit from an overall net reduction in costs in the form of Input Tax Credits ("ITCs"). This arises due to cost decreases from the receipt of additional ITCs on the purchases of goods and services previously subject to PST that become subject to the HST. These cost decreases may be partially offset by cost increases on certain items that were not previously subject to PST but become subject to the HST with no additional ITCs having been granted (i.e., these items are subject to recaptured ITC requirements).

During the 2010 IRM application process, the Board directed electricity distributors to record in Account 1592 PILs and Tax Variances, Sub-account HST/OVAT Input Tax Credits ("ITCs"), beginning July 1, 2010, the incremental ITCs received on distribution revenue requirement items that were previously subject to PST and became subject to HST.

The Board provided accounting guidance on this matter and provided a simplified approach designed to facilitate administrative cost-saving opportunities. [Frequently Asked Questions on the Accounting Procedures Handbook, December 23, 2010]

No additional amounts should be recorded in Account 1592 PILs and Tax Variances, Sub-account HST/OVAT ITCs for the Test Year and going forward, as the impact of the HST and associated ITCs on capital and operating costs in the Test Year should be reflected in the applied-for revenue requirement. For the 2012 Test Year for example entries to record variances in the sub-account of Account 1592 would cover the period July 1, 2010 to December 31, 2011 since the Test Year, which starts January 1, 2012 would include the HST impacts in it revenue requirement for 2012.

In Chapter 2, the Board expects distributors to file for disposition of account 1592 in their cost of service applications.

HHHI's application is as follows (Exhibit 9 / 2 / 1 / p. 13):

HHHI requests leave to discontinue tracking HST/OVAT/ITC as at April 30, 2012. HHHI also requests the Board allow that account 1592 remain open, pending Board approval to discontinue tracking costs effective April 30, 2012 and until such time as HHHI files its 2014 IRM rate application at which time HHHI will apply to the Board for an order to clear any audited debit or credit balance remaining in account 1592.

a) Please explain why HHHI is not requesting disposition of Account 1592.

b) Please complete and file Appendix 2-T Deferred PILs Account 1592 Balances from Chapter 2 of the Filing Requirements (June 22, 2011).

Response:

a) HHHI did not request disposition of Account 1592 because HHHI would be recording transactions in this account until December 31, 2011. The balance will be audited in Q1 of 2012.

b) Appendix 2-T Deferred PILs Account 1592 Balances from Chapter 2 of the Filing Requirements is presented below as Table OEB 1-16.

Table OEB 1-16 : Account 1592 Deferred Balances

Tax Item	Principal as of December 31, 2010
Large Corporation Tax grossed-up proxy from 2006 EDR application PILs model for the period from May 1, 2006 to April 30, 2007	
Large Corporation Tax grossed-up proxy from 2006 EDR application PILs model for the period from January 1, 2006 to April 30, 2006 (4/12ths of the approved grossed-up proxy), if not recorded in PILs account 1562	
Ontario Capital Tax rate decrease and increase in capital deduction for 2007	
Ontario Capital Tax rate decrease and increase in capital deduction for 2008	
Ontario Capital Tax rate decrease and increase in capital deduction for 2009	
Ontario Capital Tax rate decrease and increase in capital deduction for 2010	
Capital Cost Allowance class changes from 2006 EDR application for 2006	
Capital Cost Allowance class changes from 2006 EDR application for 2007	
Capital Cost Allowance class changes from 2006 EDR application for 2008	
Capital Cost Allowance class changes from 2006 EDR application for 2009	
Capital Cost Allowance class changes from 2006 EDR application for 2010	
Capital Cost Allowance class changes from any prior application not recorded above. Please provide details and explanation separately.	
HST/OVAT Input tax Credits (ITCs)	$ 32,432
Total	$ 32,432

44.

Reference: Exhibit 9, Tab 2, Schedule 3, Page 4; Chapter 2 of the Filing Requirements: Section 2.12.3; Exhibit 9, Tab 2, Schedule 1, Page 8

According to the Board letter of April 23, 2010 on the Special Purpose Charge:

In accordance with section 9 of the SPC Regulation, recovery of your SPC assessment is to be spread over a one-year period, starting from the date on which you begin billing to recover your assessment. The request for disposition of the balance in "Sub-account 2010 SPC Variance" and "Sub-account 2010 SPC Assessment Carrying Charges" should be made after that one-year period has come to an end, and all bills that include amounts on account of that assessment have come due for payment.

Chapter 2, Section 2.12.3 of the Filing Requirements states:

In accordance with Section 8 of the SPC Regulation, distributors are required to apply no later than April 15, 2012 for an order authorizing the disposition of any residual balance in sub account 2010 SPC Assessment Variance.

The Board expects that requests for disposition of the balance in Sub-account 2010 SPC Assessment Variance and associated carrying charges will be addressed as part of the proceedings to set rates for the 2012 rate year. Exceptions may apply in cases where this approach would result in non-compliance with the timeline set out in section 8 of the SPC Regulation.

HHHI stated:

HHHI established account 1521 Sub-account 2010 SPC Variance, and Sub-account 2010 SPC Assessment Carrying Charges in accordance with the Board's April 23, 2010 letter. HHHI's share of the Assessment for MEI Conservation and Renewable program of $189,128 was recognized in this account in April 2010, and customer billing for recoveries commenced May 1, 2010. As per the Board's instructions in the letter dated April 9, 2010, HHHI has recovered the SPC assessment over a one-year period on consumption after May 1, 2010 (pro-rated). As HHHI bills residential customers bi monthly, final SPC charges have been billed as of August 15, 2011. HHHI requests the Board allow that account 1521 remain open until such time as HHHI files its 2013 IRM rate application at which time HHHI will apply to the Board for an order to clear any audited debit or credit balance remaining in account 1521.

a) Please provide the most recent balance in account 1521, “Sub-account 2010 SPC Variance”.

b) Please provide the forecasted carrying charges in “Sub-account 2010 SPC Assessment Carrying Charges” as of April 30, 2011.

c) Please explain why HHHI is not seeking the disposition of the residual balances in account 1521 sub-account 2010 SPC Assessment Variance and sub-account 2010 SPC Assessment Carrying Charges in accordance with the Board’s April 23, 2919 letter and Section 2.12.3 of the Filing Requirements.

d) Is HHHI in non-compliance with the timeline set out in Section 8 of the SPC Regulation? Please explain.

Response:

a) The balance in account 1521 “Sub-account 2010 SPC Variance” at September 30, 2011 is ($15,398.48).

b) The forecasted carrying charges in “Sub-account 2010 SPC Assessment Carrying Charges” as of April 30, 2012 is $728.01

c) Please refer to HHHI interrogatory response to Energy Probe question 45.

d) No. The obligation on distributors in section 8 of the SPC Regulation is to make application to the Board by April 2012. If the Board will allow disposition on non-audited balances, HHHI would be willing to include the balance of Account 1521, including projected carrying costs to April 30, 2012 in our DVA disposition request.

45.

Reference: Exhibit 9, Tab 3, Sch. 2, Page 3

The proposed rate riders for non-RPP customers in the Residential and GS<50 kW classes in Table 9-13 appear to be inconsistent with the sub-account balances in Table 9-9 and the billing kWh amounts in Table 9-8.

Please verify the amounts in Table 9-8 and 9-9 and show the derivation of the non-RPP rate riders for those classes.

Response:

The amount in Table 9-9 is the total amount to be recovered. The rate ride Table 9-13 is based on a two year recovery period. The calculation is presented below in Table OEB 1-17.

Table OEB 1-17 : Rate Rider Calculation

	Total	Residential	GS < 50 kW	GS >50 to 999 kW	GS 999 to 4,999 kW	Sentinel Lights	Street Lighting	USL
Balance to be collected or refunded, Variable	$ (1,675,714)	$ (685,885)	$ (174,935)	$ (424,774)	$ (383,646)	$ (2,347)	$ (1,288)	$ (2,841)
Balance to be collected or refunded, Variable - Non RPP Customers (GA)	$ 2,303,654	$ 220,317	$ 45,518	$ 968,319	$ 1,025,388	$ 6,880	$ 27,866	$ 9,367
	$ 627,940	**$ (465,568)**	**$ (129,417)**	**$ 543,545**	**$ 641,742**	**$ 4,533**	**$ 26,578**	**$ 6,526**
Number of years for Variable	**2**							
Balance to be collected or refunded per year, Variable	$ (837,857)	$ (342,942)	$ (87,467)	$ (212,387)	$ (191,823)	$ (1,173)	$ (644)	$ (1,420)
Balance to be collected or refunded per year, Variable - Non RPP (GA)	$ 1,151,827	$ 110,159	$ 22,759	$ 484,159	$ 512,694	$ 3,440	$ 13,933	$ 4,683

Class	**Residential**	**GS < 50 kW**	**GS >50 to 999 kW**	**GS 999 to 4,999 kW**	**Sentinel Lights**	**Street Lighting**	**USL**
Deferral and Variance Account Rate Riders, Variable	$ (0.0016)	$ (0.0017)	$ (0.6508)	$ (0.6811)	$ (0.7926)	$ (0.0812)	$ (0.0015)
Billing Determinants	kWh	kWh	kW	kW	kW	kW	kWh
Deferral and Variance Account Rate Riders, Variable - Non RPP Customers	$ 0.0011	$ 0.0002	$ 1.4835	$ 1.8205	$ 2.3236	$ 1.7575	$ 0.0049
Billing Determinants	kWh	kWh	kW	kW	kW	kW	kWh
Rate Rider for all Customer Class	***$ (0.0016)***	***$ (0.0017)***	***$ (0.6508)***	***$ (0.6811)***	***$ (0.7926)***	***$ (0.0812)***	***$ (0.0015)***
Rate Rider for for Non -RPP Customers (GA)	***$ 0.0011***	***$ 0.0002***	***$ 1.4835***	***$ 1.8205***	***$ 2.3236***	***$ 1.7575***	***$ 0.0049***

46.

References: Exhibit 8 / 7 / 1; Exhibit 9 / 3 / 2 / p. 3; Board Report *'Electricity Distributor Deferral & Variance Account Review'* (EDDVAR) July 31, 2009; Exhibit 8 / Appendix A.

HHHI has requested a two-year period for the Deferral and Variance Account Disposition Rate Rider.

The EDDVAR Report states at p. 24:

… the default disposition period used to clear the Account balances through a rate rider should be one year. However, a distributor could propose a different disposition period to mitigate rate impacts or address any other applicable considerations, where appropriate.

a) On the Group 1 and Group 2 Deferral and Variance Account (DVA) rate rider and Non-RPP Global Adjustment rate rider by classes, please explain why HHHI is proposing 2 years instead of 1 year for the disposition period.

b) If the reason for proposing a 2-year recovery is based on a bill impact mitigation study, please provide the calculations.

c) Please re-calculate the rate riders and associated bill impacts using a disposition period of one year.

Response:

a) HHHI proposed to use a two year recovery period to lessen the financial burden on its customers.

b) HHHI didn't propose the 2-year recovery based on a bill impact mitigation study.

c) The rate riders and the bill impacts of a typical residential and GS < 50 kW customer using a disposition period of one year are presented below in Tables OEB 1-18, OEB 1-19 and OEB 1-20.

Table OEB 1-18 : Rate Impact Using One Year Disposition Period

	Total	Residential	GS < 50 kW	GS >50 to 999 kW	GS 999 to 4,999 kW	Sentinel Lights	Street Lighting	USL
Balance to be collected or refunded, Variable	$ (1,675,714)	$ (685,885)	$ (174,935)	$ (424,774)	$ (383,646)	$ (2,347)	$ (1,288)	$ (2,841)
Balance to be collected or refunded, Variable - Non RPP Customers (GA)	$ 2,303,654	$ 220,317	$ 45,518	$ 968,319	$ 1,025,388	$ 6,880	$ 27,866	$ 9,367
	$ 627,940	**$ (465,568)**	**$ (129,417)**	**$ 543,545**	**$ 641,742**	**$ 4,533**	**$ 26,578**	**$ 6,526**
Number of years for Variable	**1**							
Balance to be collected or refunded per year, Variable	$ (1,675,714)	$ (685,885)	$ (174,935)	$ (424,774)	$ (383,646)	$ (2,347)	$ (1,288)	$ (2,841)
Balance to be collected or refunded per year, Variable - Non RPP (GA)	$ 2,303,654	$ 220,317	$ 45,518	$ 968,319	$ 1,025,388	$ 6,880	$ 27,866	$ 9,367

Class	**Residential**	**GS < 50 kW**	**GS >50 to 999 kW**	**GS 999 to 4,999 kW**	**Sentinel Lights**	**Street Lighting**	**USL**
Deferral and Variance Account Rate Riders, Variable	$ (0.0033)	$ (0.0034)	$ (1.3016)	$ (1.3623)	$ (1.5852)	$ (0.1624)	$ (0.0030)
Billing Determinants	kWh	kWh	kW	kW	kW	kW	kWh
Deferral and Variance Account Rate Riders, Variable - Non RPP Customers	$ 0.0023	$ 0.0004	$ 2.9670	$ 3.6411	$ 4.6473	$ 3.5150	$ 0.0099
Billing Determinants	kWh	kWh	kW	kW	kW	kW	kWh
Rate Rider for all Customer Class	***$ (0.0033)***	***$ (0.0034)***	***$ (1.3016)***	***$ (1.3623)***	***$ (1.5852)***	***$ (0.1624)***	***$ (0.0030)***
Rate Rider for for Non -RPP Customers (GA)	***$ 0.0023***	***$ 0.0004***	***$ 2.9670***	***$ 3.6411***	***$ 4.6473***	***$ 3.5150***	***$ 0.0099***

Table OEB 1-19 : Residential Rate Impact Using One Year Disposition Period

RESIDENTIAL

		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			12.94			14.40	1.46	11.28%	12.58%
800 kWh	Distribution (kWh)	800	0.0121	9.68	800	0.0135	10.80	1.12	11.57%	9.44%
	Low Voltage Rider (kWh)	800	0.0012	0.96	800	0.0008	0.64	(0.32)	(33.33%)	0.56%
	Smart Meter Rider (per month)			1.50			2.31	0.81	53.91%	2.02%
	LRAM & SSM Rider (kWh)	800	0.0000	0.00	800	0.0007	0.56	0.56		0.49%
	Smart Meter Entity ($/Month)			0.00			0.00	0.00		0.00%
	Late Payment (kWh)	800	0.0000	0.00	800	0.0000	0.00	0.00		0.00%
	Deferrral & Variance Acct (kWh)	800	0.0019	1.52	800	(0.0033)	(2.60)	(4.12)	(271.16%)	(2.27%)
	Distribution Sub-Total			**26.60**			**26.11**	**(0.49)**	**(1.85%)**	**22.81%**
	Retail Transmisssion (kWh)	840	0.0098	8.23	848	0.0102	8.65	0.42	5.10%	7.56%
	Delivery Sub-Total			**34.83**			**34.76**	**(0.07)**	**(0.21%)**	**30.37%**
	Other Charges (kWh)	840	0.0072	6.05	848	0.0072	6.11	0.06	0.98%	5.34%
	Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0680	40.80	1.80	4.62%	35.65%
	Cost of Power Commodity (kWh)	240	0.0750	17.99	248	0.0790	19.60	1.61	8.95%	17.13%
	SPC (kWh)	840	0.0003	0.25	840	0.0000	0.00	(0.25)	(100.00%)	0.00%
	Total Bill Before Taxes			**98.12**			**101.27**	**3.15**	**3.21%**	**88.50%**
	GST		13.00%	12.76		13.00%	13.17	0.41	3.21%	11.50%
	Total Bill			**110.88**			**114.43**	**3.55**	**3.21%**	**100.00%**

Table OEB 1-20 : General Service less than 50 kW Rate Impact Using One Year Disposition Period

GENERAL SERVICE < 50 kW

		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			28.28			29.64	1.36	4.81%	10.78%
2,000 kWh	Distribution (kWh)	2,000	0.0089	17.80	2,000	0.0093	18.60	0.80	4.49%	6.77%
	Low Voltage Rider (kWh)	2,000	0.0011	2.20	2,000	0.0008	1.60	(0.60)	(27.27%)	0.58%
	Smart Meter Rider (per month)			1.50			2.31	0.81	53.91%	0.84%
	LRAM & SSM Rider (kWh)	2,000	0.0000	0.00	2,000	0.0010	2.00	2.00		0.73%
	Smart Meter Entity ($/Month)			0.00			0.00	0.00		0.00%
	Late Payment (kWh)	2,000	0.0000	0.00	2,000	0.0000	0.00	0.00		0.00%
	Deferrral & Variance Acct (kWh)	2,000	0.0020	4.00	2,000	(0.0034)	(6.75)	(10.75)	(268.70%)	(2.45%)
	Distribution Sub-Total			**53.78**			**47.40**	**(6.38)**	**(11.86%)**	**17.24%**
	Retail Transmisssion (kWh)	2,100	0.0089	18.69	2,120	0.0093	19.72	1.03	5.52%	7.17%
	Delivery Sub-Total			**72.47**			**67.12**	**(5.35)**	**(7.38%)**	**24.41%**
	Other Charges (kWh)	2,100	0.0072	15.12	2,120	0.0072	15.27	0.15	0.98%	5.55%
	Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0680	40.80	1.80	4.62%	14.84%
	Cost of Power Commodity (kWh)	1,500	0.0750	112.49	1,520	0.0790	120.11	7.63	6.78%	43.69%
	SPC (kWh)	2,100	0.0003	0.63	2,100	0.0000	0.00	(0.63)	(100.00%)	0.00%
	Total Bill Before Taxes			**239.70**			**243.30**	**$3.60**	**1.50%**	**88.50%**
	GST		13.00%	31.16		13.00%	31.63	0.47	1.50%	11.50%
	Total Bill			**270.86**			**274.93**	**$4.06**	**1.50%**	**100.00%**

47.

Reference: Report of the Board *'Transition to International Financial Reporting Standards ("IFRS")* July 28, 2009 [EB-2008-0408]; *One-Time Administrative Costs of Transition to IFRS*, section 2.7.2; Exhibit 9 / 2 / 3 / p. 4; Exhibit 9 / Appendix B

The Report of the Board states, at p. 27:

> *The Board will establish a deferral account for distributors for incremental one-time administrative costs related to the transition to IFRS. This account is exclusively for necessary, incremental transition costs and is not to include … ongoing compliance costs or impacts on revenue requirement arising from changes in the timing of the recognition of expenses.*
>
> *The Board will not restrict the IFRS transition costs account by establishing a fixed start date for amounts to be recorded. However, the Board cautions distributors that the amounts in the account will be subject to a prudence review before disposition. The criteria of materiality, causation and prudence will be considered at the time of proposed disposition. Only costs that are clearly driven by the necessity of transitioning to IFRS and are genuinely incremental to costs that would have been otherwise incurred will be recoverable in rates. Any distributor that has IFRS related costs already approved in rates must record, in a variance account, the variances between the previously approved costs and actual costs of transitioning to IFRS.*

The Regulatory Assets Continuity Schedule for sub-account 1508, Deferred IFRS Transition Costs shows a balance of $260,671 as of December 31, 2010.

a) Please confirm the Deferred IFRS transition costs show a debit balance of $260,671 as of December 31, 2010. Otherwise, please identify the costs if it is different.

b) Please provide the breakdown of the costs recorded in the IFRS Deferral sub- account as of December 31, 2010. Please provide explanations for each category of costs recorded in the IFRS Deferral account and indicate how the costs recorded meet the criteria of one-time IFRS administrative incremental costs.

c) Please confirm that no capital costs were recorded in this deferral or variance account, One-Time Administrative Costs of Transition to IFRS. If this is not the case, please explain.

Response:

a) The Deferred IFRS transition costs show a debit principal balance of $260,671 as of December 31, 2010 plus carrying charges of $3,674.

b) The costs recorded in the IFRS Deferral sub- account as of December 31, 2010 is presented in Table OEB 1-21 below.

Table OEB 1-21 : IFRS Deferral sub-account Costs

1508 - IFRS Deferral Sub - Account		Amount
Asset Management Costs for IFRS		243,685
Other Costs		8,986
Consulting Costs		8,000
		260,671

c) It is confirmed that no capital costs were recorded in this deferral or variance account, One-Time Administrative Costs of Transition to IFRS.

48.

Reference: *Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment*, June 13, 2011; Exhibit 9 / 2 / 3; Staff Discussion Paper, “Transition to IFRS” March 31, 2011 / Appendix A

In the Addendum to the Board Report, Appendix A: “Summary of Board Policy”, the Board stated at p. 31:

The Board authorizes the creation of a generic IFRS transition PP&E deferral account to record differences arising as a result of accounting policy changes caused by the transition from CGAAP to MIFRS.

HHHI’s request is as follows, at 9 / 2 / 3 / p. 1:

HHHI is requesting an Accounting Order to establish a Deferral and Variance account to track the difference relating to PP&E components of rate base as a result of transition to modified IFRS in 2012.

Differences may arise with Property, Plant, and Equipment balances due to implementing IFRS. HHHI has not provided a calculation or balance in the Board approved PP&E Deferral Account

a) Please confirm if HHHI has performed a calculation or has provided a balance in the Board approved PP&E Deferral Account.

b) If the answer to part "a" above is no, please update the appropriate schedules and calculate a balance for the PP&E Deferral Account.

c) Please provide a breakdown of the amount that is to be recorded in the PP&E deferral account from the transition date to MIFRS that is, as of January 1, 2011. Please provide the supporting analysis of the amounts in this account.

d) Please provide an analysis similar to Appendix A of the *Staff Discussion Paper – Transition to IFRS*. (The paper is available on the Board's web-site *http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2008-0408/Discussion_paper_Transition_to_IFRS_20110331.pdf*

e) Please provide a proposal for the disposition of this deferral account and rationale, referring to the Addendum to the Report of the Board on IFRS.

Response:

a) HHHI has not provided a balance in the Board approved PP&E Deferral Account.

b) The calculating and balance for the PP&E Deferral Account is presented below in Table OEB 1-22.

Table OEB 1-22 : PP&E Deferral Account Calculations

PP&E Deferral Accounts on Transition to MIFRS						
	2010	2011	2012	2013	2014	2015
CGAAP						
Opening Net PP&E	28,170,052	27,281,803				
Additions	1,860,433	4,767,523				
Depreciations	(2,748,682)	(2,796,463)				
Closing Net PP&E	**27,281,803**	**29,252,863**	**-**	**-**	**-**	**-**
MIFRS						
Opening Net PP&E	28,170,052	27,281,803				
Additions	1,860,433	4,494,747				
Depreciations	(2,748,682)	(1,139,102)				
Closing Net PP&E	**27,281,803**	**30,637,448**	**-**	**-**	**-**	**-**
Difference in Closing Net PP&E	-	(1,384,586)				
****Adjustment to 2012 Rate Base**						
PP&E Deferral Account Under MIFRS						
Opening Balance		**-**	**(1,384,586)**	**(1,038,439)**	**(692,293)**	**(346,146)**
Amount added in the Year		(1,384,586)	-			
		(1,384,586)	(1,384,586)	(1,038,439)	(692,293)	(346,146)
Amortize Amount in Deferral Account over 4 Years		-	346,146	346,146	346,146	346,146
Closing Balance	**-**	**(1,384,586)**	**(1,038,439)**	**(692,293)**	**(346,146)**	**-**
Effect on Revenue Requirement of Including Deferral Account Amortization in 2012						
Amortization of deferral Account			346,146			
Return on Rate Base -6.91%			95,675			
Amount included in 2012 Revenue Requirement			**441,821**			

c) Please refer to response to part b).
d) Please refer to response to part b).
e) Please refer to response to part b).

Smart Meters

49.

Reference: Exhibit 9 / 4 / 1; Board Decision with Reasons, “Combined Smart Meter Proceeding”, Appendix A, August 7, 2007 [EB-2007-0063]

a) Please confirm that HHHI’s costs recorded in Account 1555 and Account 1556 are directly related to the smart meter program and are incremental costs. If this is not the case, please explain.

b) Please confirm that HHHI's costs recorded in Account 1555 and Account 1556 are in accordance with the Board's Decision in the Combined Smart Meter Proceeding, Appendix A.

Response:

a) Confirmed.

b) Confirmed.

50.

References: Exhibit 9 / 4 / 2 / pp. 1-10; Exhibit 9 / 4 / 3 / p. 2; Board Decision 'Combined Smart Meter Proceeding [EB-2007-0063]; Board Guideline 'Smart Meter Funding and Cost Recovery' [G-2008-0002], October 22, 2008

The Board indicated in its Decision in the Combined Smart Meter Proceeding that certain costs that were considered "beyond minimum functionality" in relation to smart metering system costs can be recovered as part of future distribution rates. These costs may include web presentment, Customer Information System integration with the Meter Data Management/Meter Data Repository (MDM/R), consumer education, reengineering business practice and integration with retailers.

a) Please indicate if HHHI has recorded such costs and tracked them in separate sub-accounts of Account 1555 and separate sub-accounts of Account 1556 for capital expenditures and OM&A expenses, respectively. Please provide a breakdown by sub-account. If this is not the case, please explain and update the evidence.

b) Please confirm that HHHI did not include borrowing costs relating to money borrowed to finance smart meter installations, if any, as part of the Smart Meter Capital Account 1555 or Account 1556. Please identify which USoA account, if any, HHHI uses to record the borrowing costs.

c) As per the Board's "Guideline: Smart Meter Funding and Cost Recovery" (G-2008-0002) (the "Guideline"), does HHHI use its normal capitalization policy for smart meters? If this is not the case, please provide an explanation.

d) Are the stranded meter costs recorded in Account 1555 comprised of the gross costs of the stranded meters, less any capital contributions, less the accumulated depreciation and less any proceeds from the disposition of the meters?

e) Please confirm that HHHI is not recording a return on smart meters in Account 1555 or Account 1556. Otherwise, please provide an explanation.

Response:

a) HHHI incurred costs for functionality beyond the minimum functionality adopted in O.Reg. 425/06 in 2010 in relation to the purchase of 100 remote disconnect smart meters. The remote disconnect smart meters were installed in locations where the access to the meter is difficult and disconnection at the pole is the only appropriate method. The additional cost related to disconnections at the pole far exceed the addition $80.00 per remote disconnect meter and therefore is a prudent cost and should remain included in the recovery calculation.

b) It is confirmed that HHHI did not include borrowing costs relating to money borrowed to finance smart meter installations in Smart Meter Capital Account 1555 or Account 1556.

c) HHHI uses its normal capitalization policy for smart meters.

d) The stranded meter costs recorded in Account 1555 comprised of the gross costs of the stranded meters, less any capital contributions, less the accumulated depreciation. Proceeds from the disposition of the meters were recorded as revenue from scrap sales which is included revenue offset.

e) It is confirmed that HHHI did not record a return on smart meters in Account 1555 or Account 1556.

51.
Reference: Exhibit 9 / Appendix D

Please rerun and submit a revised version of the Smart Meter Model adjusting for the following two matters:

a) It appears the current (and recent models) calculate compounded interest on funding adder revenues. Please revise the model applying simple interest (i.e. interest on the opening monthly balance of the principal only) on funding adder revenues, and
b) Please revise the model to calculate simple interest expense on the opening monthly balance for OM&A and amortization expenses.

Response:

The revised model with the changes required in parts a and b will be provided shortly.

52.
Reference: Exhibit 9 / 4 / 3 / p. 4

Please re-calculate the smart meter disposition rider using the following methodology that is based on the approach approved by the Board in PowerStream's 2010 smart meter application (EB-2010-0209):

(i) Allocate the total revenue requirement for the historical years, as revised per the previous interrogatory, using the following cost allocation methodology:

- Allocate the return (deemed interest plus return on equity) and amortization based on the allocation of Account 1860 in the cost allocation model (CWMC in the cost allocation model)
- Allocate the OM&A based on the number of meters installed for each class
- Allocate PILs based on the revenue requirement allocated to each class before PILs

(ii) Sum the allocated amounts and calculate the percentages of costs allocated to customer rate classes.

(iii) Subtract the revenues generated from the smart meter funding adder from the overall revenue requirement.

(iv) Allocate the amount calculated in part (iii) by using the allocation factors derived in part (ii)

(v) To calculate the smart meter disposition rider, divide the allocated amount by rate class derived in part (iv) by the number of customers in each class, and then divide by 12.

(vi) If the proposed disposition period is greater than 1 year, divide the result of part (v) by the proposed number of years.

Response:

HHHI smart meter disposition rider using methodology that is based on PowerStream's 2010 smart meter application (EB-2010-0209) is presented below in Table OEB 1-23.

Table OEB 1-23 : Smart Meter Rate Rider Methodology

	Amount	Residential	GS<50kW	GS 50-999 kW	GS 1000-4999	Street Light	Sentinel	Unmetered Scattered Load
CWMC	5,214,821	4,414,375	364,546	377,500	58,400	-	-	-
% - Allocation		85%	7%	7%	1%	0%	0%	0%
Deemed Interest	$ 222,469	$ 188,322	$ 15,552	$ 16,105	$ 2,491	$ -	$ -	$ -
Return on Equity	$ 277,002	$ 234,484	$ 19,364	$ 20,052	$ 3,102	$ -	$ -	$ -
Amortization	$ 501,430	$ 424,463	$ 35,053	$ 36,298	$ 5,615	$ -	$ -	$ -
	$ 1,000,901	**$ 847,269**	**$ 69,969**	**$ 72,455**	**$ 11,209**	**$ -**	**$ -**	**$ -**
Number of Meter Installed	21,354	19,726	1,629					
% - Allocation	100%	92%	8%					
OM&A	**$ 1,143,544**	**$ 1,056,312**	**$ 87,232**					
Revenue Requirement before Pils	**$ 2,144,446**	**$ 1,903,581**	**$ 157,201**	**$ 72,455**	**$ 11,209**	**$ -**	**$ -**	**$ -**
Allocation % - Based on Revenue Requirement		89%	7%	3%	1%	0%	0%	0%
Pils	**$ 96,969**	**$ 86,077**	**$ 7,108**	**$ 3,276**	**$ 507**	**$ -**	**$ -**	**$ -**
Total Revenue Requirement	**$ 2,241,414**	**$ 1,989,658**	**$ 164,309**	**$ 75,731**	**$ 11,716**	**$ -**	**$ -**	**$ -**
% Cost Allocated to Customer Class	100%	89%	7%	3%	1%	0%	0%	0%
Funding Adder	-$ 1,070,487							
Smart Meter True-up	$ 1,170,928							
Allocate Smart Meter True Up	$ 1,170,928	$ 1,039,409	$ 85,836	$ 39,563	$ 6,120	$ -	$ -	$ -
Number of Customer in Class	21,542	19,726	1,629	176	12			
Smart Meter Rate Disposition Rider - 4 Year Period		**1.10**	**1.10**	**4.69**	**10.58**			

LRAM & SSM

53.

Reference: Exhibit 10 / 1 / 3 / p. 1

HHHI states that the results for OPA programs in 2010 are estimates, based on the number of installs or on methods of estimating program savings, and will be updated upon publication of the OPA final results which was expected to come in September 2011.

Please provide the final results for the 2010 OPA programs HHHI delivered. If the final results are not available, please indicate when HHHI expects to receive them.

Response:

The final OPA-verified results of the 2010 OPA programs were received via an email to HHHI from LDC support (**LDC.Support@powerauthority.on.ca**) dated September 19, 2011. The final results summary for 2011 OPA programs can be found in Appendix OEB 1-E.

The LRAM claimed by HHH was updated to incorporate the final OPA-verified results of the 2010 OPA programs. All other assumptions and inputs remained unchanged from claim originally filed as Exhibit 10 of HHHI's cost of service application EB-2011-0271.

HHH recommends that its LRAM claim be updated from the original claim of $426,806, to a claim of 383,381, including $17,239 in carrying charges. The requested SSM claim remains at $1,417.

Table OEB 1-24 : Summary of Updated LRAM and SSM

Rate class	Updated LRAM	SSM
Residential	$276,155	($448)
GS < 50 kW	$73,353	$436
GS 50 to 999 kW	$28,060	$1,430
GS 1,000 to 4,999 kW	$5,813	$0
Total	**$383,381**	**$1,417**

The updated two-year rate riders are as follows.

Table OEB 1-25 : Updated Rate Riders

Class	**Updated LRAM**	**Updated carrying charges**	**SSM**	**Updated total**	**Unit**	**2012 forecasted billed kWh/kW**	**Updated two year rate rider $/unit**
Residential	$261,496	$14,659	($448)	**$275,707**	kWh	210,909,970	**0.0007**
GS<50 kW	$71,782	$1,572	$436	**$73,789**	kWh	51,848,139	**0.0007**
GS 50 - 999 kW	$27,176	$884	$1,430	**$29,490**	kW	326,358	**0.0452**
GS 1,000 - 4,999 kW	$5,688	$125	$0	**$5,813**	kW	281,618	**0.0103**
Total	$366,142	$17,239	$1,417	$384,798			

At a four-digit level of precision, the residential two-year rate rider did not change. The two-year GS < 50 kW rate rider decreased from $0.0010/kWh to $0.0007/kWh. The two-year GS 50-999 kW rate rider decreased from $0.0562/kW to $0.0452/kW and the two-year GS 1,000-4,999 kW rate rider decreased from $0.0190/kW to $0.0103/kW.

54.
Reference: Exhibit 10 / 1 / 3 / p. 1

HHHI notes that the reduction in demand related to its CDM programs has been incorporated into the load forecast for May 1, 2012 onward. It further states however, that energy savings related to OPA programs delivered in 2011 have not been captured.

a) Please confirm that HHHI has not included any losses related to 2011 OPA programs in this LRAM application.

b) If part a) is not confirmed, i.e. if HHHI has included losses attributable to 2011 OPA programs, please discuss the rationale for doing so.

Response:

a) HHHI did not include any losses related to 2011 OPA programs in its LRAM application. HHHI included LRAM claims for revenue losses between 2006 and April 30 2012 for programs launched in 2006, 2007, 2008, 2009, and 2010. Revenues lost in 2011 and between January and April 30 2012 are a result of energy savings from 2006, 2007, 2008, 2009, and 2010 programs that have persisted into 2011 and the first four months of 2012.

b) HHHI did not include any losses related to 2011 OPA programs in its LRAM application.

55.

Reference: Exhibit 10 / 1 / 3 / p. 4 Table 10-4

HHHI provides a table outlining its LRAM amounts by funding source.

a) Please confirm that HHHI has used the most recently published OPA Input Assumptions lists when calculating LRAM for Third Tranche programs.

b) If HHHI has not used the most recently published OPA Input Assumptions list when calculating LRAM for its Third Tranche programs, please discuss the rationale for not doing so.

Response:

a) The most recently published OPA input assumption lists are the 2011 Prescriptive and Quasi-prescriptive OPA Measures and Assumptions lists. HHH used the most recent 2011 Prescriptive and Quasi-prescriptive OPA Measures and Assumptions lists for all measures within its Third Tranche programs, with the exception of an LRAM claim associated with the installation of 250W metal halide bulbs.

b) HHH did not use the most recently published OPA input assumption lists for the LRAM claim associated with the installation of 250W metal halide bulbs since this measure is not included in these lists. The best available input assumptions for 250W metal halide bulbs were used to calculate its LRAM claim. These best available input assumptions were found in the 2008 OEB TRC Input Assumptions List. The total LRAM claim associated with the installation of 250W metal halide bulbs was $421.

56.
Ref: Exhibit 10 / Appendix A 'Third Party Review …'

IndEco notes in its third party review, at p. 6, that that energy savings for measures installed between 2006 and December 31, 2010 were calculated to April 30, 2012.

a) Please confirm that HHHI is requesting recovery of lost revenues estimated to April 30, 2012 for programs started between 2006 and December 31, 2010.

b) If part a) is confirmed, please discuss the rationale for requesting recovery of estimated lost revenues until April 30, 2012 in the absence of verified program results for both the 2011 program year and January 1, 2012 to April 30, 2012.

c) If part a) is confirmed, please provide an updated LRAM amount exclusive of estimated lost revenues past December 31, 2010.

Response:

a) Yes, HHHI is claiming recovery of lost revenues estimated to April 30 2012 for programs started between 2006 and December 31 2010.

b) HHHI is **not** requesting recovery of lost revenue associated with unverified programs delivered in 2011, or unverified programs delivered between January 1 and April 30 2012. The requested lost revenues in 2011 and the first four months of 2012 are associated with verified savings arising from programs that were delivered in 2006, 2007, 2008, 2009, and 2010.

   A distinction must be made between lost revenue in 2011 due to programs delivered in 2011, and lost revenue in 2011 due to programs delivered in earlier years. A program will lead to energy savings, and thus lost revenues, that will persist over the lifetime of the program's measures. For example, if a 2006 program consists of a measure with a lifetime of six years, the program will lead to lost revenues each year until the end of 2011. This would be unrelated to lost revenue due to a program delivered in 2011.

Table OEB 1-26 below illustrates the verified results that were used to calculate HHHI's LRAM claim. Note that no programs delivered in 2011 were included in the LRAM claim.

OEB 1-26 : Verified Results

	Lost revenues are requested for the following verified program results:						
Program	2006	2007	2008	2009	2010	2011	Jan - Apr 30, 2012
Programs delivered in 2006	Verified results	Verified results	Verified results	Verified results	Verified results	Verified results	Verified results
Programs delivered in 2007		Verified results	Verified results	Verified results	Verified results	Verified results	Verified results
Programs delivered in 2008			Verified results	Verified results	Verified results	Verified results	Verified results
Programs delivered in 2009				Verified results	Verified results	Verified results	Verified results

c) An LRAM amount exclusive of estimated lost revenues past December 31 2010 is provided in the Table OEB 1-27 below. HHHI feels that this LRAM claim would not be the appropriate claim amount for programs delivered in 2006, 2007, 2008, 2009, and 2010 since lost revenue between January 1, 2011 and April 30, 2012 associated with these programs would be unaccounted for.

Table OEB 1-27 : LRAM Amounts Exclusive of Estimated Loss Revenues

Rate class	**LRAM for the period between January 1 2006 and December 31 2010**
Residential	$229,219
GS < 50 kW	$54,922
GS 50 to 999 kW	$22,972
GS 1,000 to 4,999 kW	$5,685
Total	**$312,798**

Bill Impacts

57.

Reference: Exhibit 8 / Appendix A; Exhibit 9 / 3 / 2 / p. 3

a) HHHI prepared bill impact calculations, in consultation with Board staff, for use in the published Notice of Application that differ from the pre-filed calculations in Exhibit 8 and in the Revenue Requirement Work Form Excel spreadsheet. Please provide documentation of the revised bill impact calculations for a Residential customer using 800 kWh per month and a General Service customer in the 'less than 50 kW' class using 2000 kWh per month.

b) Impact calculations are included for customers outside the size range for the General Service 50 – 999 kW class (calculations for 2000 and 4000 kW customers), and for the General Service 1000 – 4999 kW class (calculations for 6500 kw – 13,900 kW). Please provide impact calculations for customers with 500 and 999 kW at rates in the smaller class, and for customers over a suitable range within the larger class.

c) Impact calculations are provided in the pre-filed evidence only for RPP customers. Please provide a parallel set of calculations for non-RPP customers, by combining the two proposed rate riders that would apply to the non-RPP customers in each class.

Response:

Revised bill impacts will be provided when HHHI updates the revenue requirement (IR # 60) and updated RRWF (IR# 61)

Requests for Accounting Orders

58.
References : Exhibit 1 / 1 / 7; Exhibit 9 / 2 / 3; Exhibit 9 / Appendix C

HHHI is requesting an accounting order to establish a deferral or variance account to track costs incurred in Tier 3 programs prior to Board approval. A prospective budget amount of $1,762,000 is provided in Appendix C "Addendum to Halton Hills CDM Strategy" Table A-2.

a) Please provide the expected timing of expenditures for Board-approved CDM programs and expected timing of Board review (and approval).

b) With reference to Board Frequently-Asked Questions about the Accounting Procedures Handbook, December 23, 2010, # 22, account 1567 appears to meet HHHI's request for approval of an account. Has HHHI reviewed the description of account 1567, and if so, please provide clarification on HHHI's request for approval of an additional account.

Response:

a) HHHI expects to have a decision on Board-approved CDM programs within the first quarter of 2012 with implementation expenditures planned for mid to later 2012 and into 2013.

b) Account 1567 is appropriate to record costs after Board-approval of HHHI's Tier 3 programs. However, there is currently no deferral account appropriate for cost associated with the preparation of an application to the Board for its approval. HHHI is requesting an additional account to track the design and preparation costs and would request an order to transfer these costs to Account 1567 upon approval of the requested Tier 3 CDM programs.

59.

References: Exhibit 1 / 1 / 4 / p. 2; Accounting Procedures Handbook, Frequently Asked Questions about the Handbook, December 23, 2010, #22.

HHHI's request is as follows:

Approval to establish a Deferral and Variance account to track costs incurred in the preparation and implementation of Board-Approved Conservation and Demand Management Programs, prior to Ontario Energy Board approval of said programs.

The Board response to the FAQ states, at p. 25:

The account is Account 1567, Board-Approved CDM Variance Account. A distributor should track its spending for its Board-Approved CDM Programs in this variance account, which should be used to record the difference between the funding awarded for Board-Approved CDM Programs and the actual spending incurred for these Programs.

a) Please confirm if HHHI has received Board approval for its CDM Programs which HHHI plans to record in the proposed CDM Variance account.

b) Has HHHI incurred actual spending for these Programs?

Response:

a) HHHI has not yet received Board approval for its proposed Tier 3 CDM Programs. HHHI is currently working with the OPA to ensure the proposed programs are not duplicative of OPA programs. Upon acceptance by the OPA, HHHI will submit the programs to the Board for approval.

b) HHHI has incurred approximately $30,000 in costs to design and prepare the Tier 3 CDM programs for review by the OPA.

Updated Revenue Requirement

60.

Reference: Exhibit 1 / 1 / 4 / p. 1

Upon completion of responses to all interrogatories, please identify any adjustments to the proposed base and service revenue requirements that the applicant wishes to make relative to the original application.

Response:

To be provided shortly.

Updated RRWF

61.

Upon completing all interrogatories from Board staff and intervenors, please provide an updated RRWF with any corrections or adjustments that the applicant wishes to make to the amounts, including documentation such as an explanatory note or a Reference to an interrogatory response. (Please show the revisions in the middle column of the applicable worksheets, leaving unchanged the leftward columns labelled 'Initial Application'.)

Response:

To be provided shortly.

APPENDIX OEB 1-A

Halton Hills Hydro Inc.
IFRS - Capitalization Policy

IFRS - Capitalization Policy

Standard: IFRS 1 – Elective Exemption, IAS 16 – Property, Plant and Equipment

Topic: Property, Plant and Equipment – Fair Value vs. Carrying Value as Deemed Cost

Objective:

To determine the policy on initial measurement of property, plant and equipment (PP&E) on the date of transition to IFRS

Background:

Halton Hills Hydro Incorporated ("HHHI") may elect to measure an item of PP&E at its fair value on the date of transition to IFRS. The fair value would then represent deemed cost at that date for purposes of subsequent measurement and amortization ("deemed cost election").

An additional IFRS 1 exemption is available to rate regulated entities. The exemption allows an entity to measure an item of PP&E at its previously recorded carrying value (i.e. net book value) on transition to IFRS. As HHHI's operations are rate regulated, they are eligible to apply this exemption.

If an Elective Exemption with respect to PP&E is not taken, HHHI would have to account for PP&E as if the requirements of IAS 16 had always been applied. This would require retrospective restatements of all PP&E balances in accordance with IFRS.

Considerations:

Retroactive restatements will be onerous and impractical as documentation for historical costs are not available.

The fair value exemption is not allowed by the OEB for rate setting purposes.

Fair values are more costly to obtain.

Electing the IFRS 1 exemption for rate regulated entities is more favourable to HHHI. Regulated Net Book Value as at the date of transition to IFRS would be used for rate setting purposes. The OEB requires the use of regulated NBV as the basis for setting the opening rate base values upon transition to IFRS. Therefore, using the carrying value as deemed cost exemption would more closely align financial reporting with the basis in which regulated cash flows and income are determined by the regulator.

Conclusion:

HHHI has concluded that it will elect the IFRS 1 Exemption for rate regulated entities and use net book value as at date of transition to IFRS (January 1, 2012) as deemed cost.

Standard: IAS 16 – Property, Plant and Equipment

Topic: Property, Plant and Equipment – Measurement after Recognition

Objective:

To determine the policy on measurement of property, plant and equipment (PP&E) after initial recognition

Background:

For all subsequent periods following the initial recognition of an asset, IAS 16 permits a choice of using either the cost model or the revaluation model for valuing PP&E.

Cost Model

After recognition as an asset, an item of PP&E shall be carried at its cost less any accumulated depreciation and any accumulated impairment losses.

Revaluation Model

After recognition as an asset, an item of PP&E whose fair value can be measured reliably shall be carried at a revalued amount, being its fair value at the date of the revaluation less any subsequent accumulated depreciation and subsequent accumulated impairment losses. IAS 16 defines fair value as “the amount for which an asset could be exchanged between knowledgeable, willing parties in an arm’s length transaction.” It also mentions that, if there is no market-based evidence of fair value because of the specialized nature of a particular PP&E item and the item is rarely sold (except as part of a continuing business), an entity may need to estimate fair value using an income or a depreciated replacement cost approach.

Revaluation shall be made with sufficient regularity to ensure that the carrying amount does not differ materially from that which would be determined using fair value at the end of the reporting period. If an item of PP&E is revalued, the entire class of PP&E to which that asset belongs shall be revalued.

Ontario Energy Board

In its report of the Board on Transition to International Financial Reporting Standards, the OEB will require the use of historical acquisition cost as the basis for reporting PP&E for regulatory purposes.

Conclusion:

HHHI has concluded that it will choose the Cost Model to measure PP&E after initial recognition under IFRS.

Standard: IAS 16 – Property, Plant and Equipment

Topic: Componentization and Depreciation

Objective:

To document the accounting policy on componentization and depreciation of property, plant and equipment.

Background:

Each part of an item of property, plant and equipment (PP&E) with a cost that is significant in relation to the total cost of the item shall be depreciated separately.

An entity should allocate the amount initially recognized in respect of an item of PPE to its significant parts to be depreciated separately.

A significant part of an item of PP&E may have a useful life and a depreciation method that are the same as the useful life and the depreciation method of another significant part of that same item. Such parts may be grouped in determining the depreciation charge.

Depreciation is to be computed on a systematic basis over the estimated useful life of the item of PP&E. The depreciable amount of an asset is determined after deducting its residual value. In practice, the residual value of an asset is often insignificant and therefore immaterial in the calculation of the depreciable amount.

The residual value and the useful life of an asset shall be reviewed at least at each financial year-end and, if expectations differ from previous estimates, the change(s) shall be accounted for as a change in an accounting estimate in accordance with **IAS 8** *Accounting Policies, Changes in Accounting Estimates and Errors.*

Depreciation of an asset begins when it is available for use (i.e. when it is in the location and condition necessary for it to be capable of operating in the manner intended by management). Depreciation of an asset ceases at the earlier of the date that the asset is classified as held for sale in accordance with **IFRS 5** and the date that the asset is derecognized.

Considerations:

Significant components of PP&E will be separately accounted under IFRS. Each significant component and the estimated useful lives, for purposes of computing depreciation expense under IFRS, will be set out in Table 1 as attached.

Overhead system

The following components have been identified – poles, conductors, transformers, switches, municipal substations comprised of DC service station, switchgear, and transformer.

<u>Poles</u>

HHHI has wood, steel and composite poles. HHHI has 8,000 poles of which 10 are composite, 1 is useful lives of the cross-arms and insulators are consistent with the pole. Insulators may be changed more frequently, however the cost in comparison to the cost of a pole is insignificant. Therefore, brackets, cross-arms and insulators will have the same useful lives as the pole and will be included as a fully dressed pole.

Engineering will test the condition of the pole rather than the age when determining if a pole should be changed. Engineering have preliminarily determined the average life of poles in the system to be approximately 60 years, while the Kinectrics Inc. Report No: K-418022-RA0001-R003, dated December 10, 2009 (HHHI Kinectrics report) shows a maximum life of 50 years. However, the study was commissioned before HHHI had any asset management initiatives and the results of the current pole testing shows that poles are requiring changing at an approximate age of 40-45 years. Therefore, a useful life of 50 years is reasonable.

<u>Conductor</u>

The HHHI Kinectrics report reflects a useful life between 50-77 years, with a typical useful life of 60 years based on moderate mechanical stress, low electrical loading and moderate environmental factors. Conductor in the system is under moderate mechanical stress and moderate electrical loading which suggests that useful life is lower than typical. On average, the change of pole dictates the change of conductor. Load growth also dictates the change in conductor. As a result, a useful life of 50 years will be used which is consistent with the useful life of the poles.

Transformer

Pole mounted transformers typically have a different useful life than the pole and conductor. When a pole is removed along with a pole mounted transformer, the transformer could be sent in for service and re-used at a future date. The transformer is a significant component of PP&E and the transformer could have a different useful life than the pole. Therefore, transformers will be a separate component and will be categorized between pad mounted transformers and overhead transformers.

The HHHI Kinectrics report reflects a useful life between 30-60 years, with a typical useful life of 40 years based on moderate electrical loading and environmental factors. HHHI has moderate electrical loading and moderate environmental conditions which would trend towards the typical life as the useful life of the transformer. Therefore, the typical useful life of 40 years is to be used for transformers.

Switches

The majority of the switches in use today by HHHI are manual overhead switches. HHHI's capital plan includes the installation of remote automated switches. A separate component for local motorized switches is not required as most switches will be automated and remote going forward. Automated switches are currently segregated in the capital budget by switch ($30,000), motor and RTU ($10,000). Therefore, all the pieces of automated switches are to be kept together, and all switches (fuse cut-outs, overhead switches and remote automated) are to be included as one component – overhead devices. HHHI has fuse cut-outs which are transformer switches. These items have a low dollar value ($100-$150).

The HHHI Kinectrics report reflects a useful life between 30-60 years, with a typical useful life of 50 years. Switch maintenance practices at HHHI are low; therefore life should be closer to the minimum identified in the HHHI Kinectrics report rather than the typical useful life. Over the past 35 years, only a few switches have needed to be replaced. The ages of these switches are approximately 40 years old. There are some cut-out switches that are only 10-15 year old; however these are small dollar value ($150 each). Therefore, the useful life of 40 years is to be used.

Voltage Regulator

The useful life of the voltage regulator is the same as the transformer. Therefore, there is no need to keep a separate component for the voltage regulators.

Reclosers

Reclosers are a type of switch and are currently included in devices and do not need to be separated from switches due to lack of significance in dollar value.

Municipal Substations

HHHI currently has 11 outdoor municipal substations and 1 indoor municipal substation. There is a high dollar value in the substations with the majority of the cost relating to the transformer with minor costs relating to fencing and building. Based on HHHI's experience, the tap changer is most likely to be replaced before the winding. The tap changer is a significant cost to replace although the majority of the cost is in the transformer itself. The building and fencing do not have a large dollar value in relation to each other. Therefore, all parts of the building (building and fence) for the municipal substation should be grouped together with the power transformer being one component comprised of the transformer, winding and tap changer.

The HHHI Kinectrics report shows a useful life of 32-55 years, with a typical useful life of 45 based on moderate electrical loading and environmental factors and low operating and maintenance practices. HHHI operating and maintenance are low. Engineering is finding that after 17-30 years of age maintenance costs increase. HHHI environmental factor would be a little higher than moderate as only one out of twelve municipal substations is indoor. Therefore the useful life should be lower than typical and a useful life of 35 years would be reasonable.

DC Service Station

The DC station service asset class includes battery banks and chargers. Based on HHHI's experience, batteries do not last as long as chargers. According to the HHHI Kinectrics report the battery and chargers have similar useful lives. Therefore, DC Station service will be one component comprising the battery and charger.

The HHHI Kinectrics report shows a useful life of 10-30 years, with a typical useful life of 20 years, based on moderate electrical loading, low environmental factors and moderate maintenance practices and moderate non-physical factors. For HHHI, the non-physical factors (technology) are low and environmental factors are also low as DC systems are indoors. A useful life of 20 years is typical of the charger (battery depends on the technology and normally does not last longer than charger). Therefore the useful life of 20 years would be reasonable.

Switchgear

HHHI operates with both air and gas insulated switchgear. As required, the air insulated switchgear is replaced with the latest design of metalclad gas insulated switchgear. The useful life expected by HHHI is the same which is supported by the lives identified in the HHHI Kinectrics report. The HHHI Kinectrics report has been broken out by type of switchgear – air vs. gas. When the switchgear requires replacement, HHHI typically replaces the whole switchgear, not just the parts within the switchgear. Therefore, the switchgear assembly should continue to be combined into one component – switchgear; and the type - air and gas switchgear should be grouped together as one component.

Kinectrics shows a useful life between 30-60 years, with a typical useful life of 40 years based on low electrical loading, moderate environmental factors, and operating and maintenance practices. Typical useful life of 40 years is accurate according to engineering. Electrical loading in the system is high and environmental factors are low as switchgear is all indoor. These factors offset each other. Experience of one engineer reveals that they have seen only one switchgear (air or gas) replaced which had an approximate 40 year useful life. Therefore, a useful life of 40 years is reasonable.

Station Grounding Systems

HHHI will replace the grounding system when the transformer is replaced. Therefore, the station grounding system will continue to be grouped together with transformers.

Underground System

The following possible components were identified – primary cable, secondary cable, transformers, switchgear, utility chamber, ducts, transformer switchgear foundation, junction cubicle, SCADA, fault indicator, metering, and smart meters.

Underground Primary Cable

HHHI utilizes only TRXLP cable within its underground distribution system. HHHI stopped direct burying cables approximately 20-25 years ago. The net book value of direct buried cable is expected to be nil. All new underground primary cable is installed – encased in duct or concrete. Based on HHHI's experience, induct and concrete have the same useful life. Arrestors and terminations are an insignificant part of the cost of the underground network and have a life similar to that of the cable. Therefore arrestors, terminations and elbows will be grouped together as one component in underground primary cable.

The HHHI Kinetrics report identified the useful life of underground primary cable including termination, arrestors, utility chambers and elbows of 40-60 years, with a typical useful life of 40 years based on moderate mechanical stress, electrical loading and environmental factors. Experience has shown cable does not require change out before 40 years; therefore a 40 year useful life is reasonable.

Secondary Cable

HHHI has both induct and direct buried secondary cable. All new underground secondary cable installed is encased in duct or concrete. HHHI does not have any PI and PIJ cables. Therefore, induct and direct buried cables will be grouped together.

The HHHI Kinectrics report identifies a useful life between 40-60 years, with minimum and typical useful life at 40 years. This is based on moderate mechanical stress, electrical loading and environmental factors. A useful life of 40 years is appropriate as normally change of secondary cables is due to electrical loading issues rather than failure and experience shows secondary cables are not changed out before then. Therefore, a useful life of 40 years is appropriate.

Transformers

Transformers are a significant part of the underground system.

The HHHI Kinectrics report reflects the useful life between 30-40 years, with a typical life of 40 years based on low mechanical stress and moderate electrical loading and environmental factors. HHHI has low electrical loading in their underground system which would put the useful life towards the maximum which is the same as typical. A useful life of 40 years is therefore appropriate.

Pad Mounted Switchgear

HHHI operates with both air and gas insulated switchgear. Experience has indicated that both air and gas switchgear have the same useful lives and this is supported by the HHHI Kinectrics report.

The HHHI Kinectrics report indentifed the useful life between 20-40 years, with a typical useful life of 30 years based on low mechanical stress and electrical loading and high environmental factors. Environmental factor is high as the assets tend to rust as they sit at the side of the road, so the snow, debris, salt, etc. factor into the condition of the asset. The approximate age is 25 to 30 years; therefore a 30 year useful life is appropriate.

Utility Chamber

The Utility Chamber facilitates cable pulling into underground ducts and provide access to splices and facilities that require periodic inspections or maintenance. HHHI currently has two utility chambers and has typically experienced that these chambers have a similar useful life to the conductor. Utility chambers are expensive to install, but they last a long time. Therefore, utility chambers are to be grouped with underground primary cable.

Ducts

The HHHI Kinectrics report shows a useful life from 30-80 years, with a typical useful life of 50 years based on high mechanical stress and moderate environmental factors. In HHHI's system, mechanical stress is not high and ducts underground are normally concrete encased and are therefore protected. They should therefore have a higher life than underground cable and a useful life of 50 years is reasonable.

Transformer and Switchgear Foundation

The transformer and switchgear foundation asset class is similar to the utility chamber asset. It is a buried precast concrete vault on which the pad-mounted transformers or switchgear are mounted. Typically the foundation is buried and the top portion is above ground. The transformer switchgear foundation is usually installed when the duct is installed. Therefore, duct and transformer switchgear foundation are to be grouped together.

Junction Cubicle

Junction cubicle is similar to switchgear but it is less expensive. According to the HHHI Kinectrics report, junction cubicle and switchgear useful lives are similar. As such, junction cubicle is to be grouped with the pad mounted switchgear.

SCADA

Supervisory Control and Data Acquisition (SCADA) refers to the centralized monitoring and control system of a facility. SCADA remote units (RTUs) allow the SCADA system to communicate with field equipment. The RTU is typically comprised of power supply, CPU, I/O Modules, housing and chassis, communications interface and software.

The HHHI Kinectrics report identifies a SCADA useful life between 5-30 years, with a typical useful life of 20 years based on low environmental and maintenance practices and high non-physical factors. For HHHI, the environmental and maintenance factors are low. The non-physical factor is high as SCADA is technology-based. The life of SCADA equipment is limited by technology. Therefore a 20 year useful life is appropriate based on non-physical.

Fault Indicator

HHHI has approximately 45 fault indicators comprised of both overhead and underground. The cost of a fault indicator is approximately $200-500. Overhead fault indicators should be grouped with overhead conductor and underground fault indicators are used with transformers and should be grouped with the underground transformers.

Metering

The metering asset consists of three components: the meter itself, the current transformer (CT) and the potential transformer (PT

HHHI typically recalibrates industrial/commercial meters every 10 years. As industrial and wholesale meters last the same amount of time, they will be grouped together.

The HHHI Kinectrics report shows a useful life range of industrial/commercial type meters between 20 -60 years. The non-physical factors are high due to technology and life is limited by technology. A 20 year useful life is reasonable.

Rarely, is HHHI required to replace CTs and PTs; only if they are hit by lightning or other electrical issues. CTs and PTs last a lot longer than a meter. As a result, CTs and PTs should be segregated from industrial and wholesale meters.

The HHHI Kinectrics report shows a useful life between 35-50 years, with a typical useful life of 45 years based on low maintenance. CTs & PTs typically last about 45 years. Useful life of 45 years will be used.

Smart Meters

A smart meter is an advanced meter, essentially an electrical meter that identifies consumption in more detail than a conventional meter; and communicates that information via repeaters and collectors back to the local utility. HHHI expects that repeaters, antennas and data connectors would easily last as long as the meters, but they are based on technology and this impacts their useful life as these are communication based. Smart metering is a 20 year plan. Cost information should be kept in as much detail as in the Kinectrics chart – smart meters, repeaters, data concentrators.

The HHHI Kinectrics report reflects a minimum life for all smart meters of 15 years to be deemed appropriate as this is new technology with no history. Technology is considered to be a life limiting factor.

Minor Assets

With reference to the HHHI Kinectrics report:

1. Vehicles will be separated into the following categories and useful lives will be based on HHHI replacement policy as follows:
    - bucket trucks, useful life of 12 years
    - trailers, useful life of 15 years and
    - Vans/cars/light vehicles, useful life of 8 years.

2. Office equipment - a 5 year useful life.

3. Computer hardware and software is technology driven. The life is determined to be 3 years and 2 years respectively.

4. Tools, shop, garage equipment and measurement & testing equipment are to be bundled together and useful life is determined to be 10 years.

5. Stores equipment with useful life of 10 years.

6. Communication equipment including vehicle radio will continue to use the current useful life of 10 years.

Conclusion:

The new levels of componentization and the corresponding useful lives will be applied beginning January 1, 2012. The net book value as deemed cost exemption (available to rate regulated entities) will be applied so that the opening values at January 1, 2012 do not need to be restated and therefore, componentization does not need to be applied retroactively.

Table 1: HHHI – PP&E Components and Estimated Useful Lives

Component	Previous Component	Proposed Useful Life	Existing Useful Life
Land	Land	N/A	N/A
Overhead poles, fully dressed	Overhead Poles	50	25
Overhead conductors	Overhead Conductors & Devices	50	25
Overhead line switches, reclosures, fault circuit indicators	Overhead Conductors & Devices	40	25
Municipal substations – transformers incl grounding system	MS Station equipment	35	25
Municipal substations - DC service station incl battery & chargers	MS Station equipment	20	25
M.S. Switchgear	Overhead Conductors & Devices	40	10
Underground primary cable incl utility chambers	Underground Conductors & Devices	40	25
Underground secondary cable	Underground Services	40	25
Underground ducts and transformer switchgear foundation	Underground Conduit	50	25
Overhead transformers incl voltage regulator	Overhead Transformers	40	25
Underground transformers incl fault indicators	Underground Transformers	40	10

Underground switchgear and junction cubicle		30	-
SCADA – battery, RTU, relay, IED		20	15
Industrial/Commercial, wholesale Energy Meters	Interval Meters – 1 Phase, 3 Phase & Meters YE Adj	20	25
PTs & CTs	Meters	45	25
Smart meters - meters	Meters	15	15
Smart meters - repeaters	Meters	15	15
Smart meters – data concentrators	Meters	15	15
Office Furniture and Equipment	Office Furniture and Equipment	5	10
Computer Equipment Hardware	Computer Equipment Hardware	3	5
Computer Software	Computer Software	2	1
Vehicles – bucket trucks	Transportation Equipment	12	5
Vehicles – trailers	Transportation Equipment	15	5
Vehicles – vans/cars	Transportation Equipment	8	5
Tools, Garage Equipment, Measurement & Testing Equipment	Tools, Garage Equipment, Measurement & Testing Equipment	10	10
Stores Equipment	Stores Equipment	10	10
Wireless Communication	Communication Equipment	10	-

Standard: IAS 16 – Property, Plant and Equipment

Topic: Capitalization - Burdens

Objective:

To document the accounting policy on the capitalization of burdens.

HHHI will capitalize all costs, including the above burdens, when the cost is directly attributable to bringing the item of PP&E to the location and condition necessary for it to be capable of operating in the manner intended by management.

Any general and administrative costs currently included in the various burden rates under CGAPP will not be capitalized under IFRS.

The following changes were made to the capitalization policy as a result of the transition to IFRS.

Payroll allocation

The following accounts were removed from this allocation as they are not directly attributable to an asset:

- Non-Productive Time (account 670-14-21)
- Major Tools Amortization (account 670-14-22)
- Payroll Overhead Management Cost (account 670-26-13/14/15/17)
- MEARIE – Total Benefits (account 670-26-26)
- Department/ OH Recovery (account 670-90-89)

Stores Allocation (Materials Burden)

No changes were identified for this allocation.

Rolling Stock (Vehicle Burden):

No changes were identified for this allocation.

Standard: IAS 16 – Property, Plant and Equipment

Topic: Property, Plant and Equipment Derecognition of PP&E

Objective:

To document the accounting policy on derecognition of property, plant and equipment.

Background:

The carrying amount of an item of property, plant and equipment (PP&E) shall be derecognized:

(a) On disposal; or

(b) When no future economic benefits are expected from its use or disposal (eg. the item is removed from use).

When a part of an item of PP&E is replaced and that replacement is capitalized under the recognition principle in IAS 16, then the replaced part is derecognized regardless of whether the replaced part has been identified as a separate component and depreciated separately.

The gain or loss arising from the derecognition of an item of PP&E shall be included in profit or loss when the item is derecognized. Gains shall not be classified as revenue, and instead should be presented as other income or expense.

The disposal of an item of PP&E may occur in a variety of ways (e.g. by sale, by entering into a finance lease, by donation, etc.) In determining the date of disposal of an item, an entity applies the criteria in IAS 18 for recognizing revenue from the sale of goods. Under IAS 18.14, revenue from the sale of goods shall be recognized when all the following conditions have been satisfied:

(a) The entity has transferred to the buyer the significant risks and rewards of ownership of the goods

(b) The entity retains neither continuing managerial involvement to the degree usually associated with ownership nor effective control over the goods sold;

(c) The amount of revenue can be measured reliably;

(d) It is probable that the economic benefits associated with the transition will flow to the entity; and

(e) The costs incurred or to be incurred in respect of the transactions can be measure reliably.

The gain or loss arising from derecognizing of an item of PP&E shall be determined as the difference between the net disposal proceeds, if any, and the carrying amount of the item.

Considerations:

Currently the pooled method of accounting for capital assets for Utility companies is applied and is an approved method by the Ontario Energy Board (“OEB”).

The pooled method of accounting, pools like assets together based on the year of addition as the pooling method assumes that each asset will last, on average, their full useful life

Under the pooled method there is an assumption that there are assets within the same asset pool which will last longer or shorter than the estimated useful life and therefore, in the end everything balances out on average. However, the assumption does not always hold true, especially if assets are removed from service before the end of their useful life, for example, when a road is widened and a pole line relocated.

Under the pooled method, if an asset is removed from service prior to the end of its useful life, there is no change to the accounting to remove the asset – it remains in the GL (ie it is not derecognized).

Currently, HHHI records their capital assets using the pooling method of accounting and does not derecognize assets removed from service prior to the end of their useful life.

Since HHHI removes assets from service prior to the end of their useful life from time to time, these removed assets should be derecognized. HHHI must derecognize the cost of the asset which was removed/disposed. A write-off would be recorded in the amount of the remaining NBV of the asset removed/disposed. Any proceeds on the disposal of the asset would offset the write-off.

Conclusion:

In order to properly account for assets that are removed from service in the accounting records, a collaborative process needs to be developed involving Engineering, Operations and Finance which alerts the accounting department when an asset has been removed from service in order to write-off the asset (long-term issue)

If a project include only the addition of a new asset, without any removal of old assets, then there are no de-recognition losses to record.

Standard: IAS 23 – Borrowing Costs

Topic: Borrowing Costs – Property, Plant and Equipment

Objective:

To determine the policy on accounting for borrowing costs for property, plant and equipment.

Background:

Borrowing costs are interest and other costs that an entity incurs in connection with the borrowing of funds. A qualifying asset is an asset that necessarily takes a substantial period of time to get ready for its intended use or sale. A substantial period of time is not defined in the IAS standard. Guidance provided by KPMG (Insights) suggests that a substantial period of time would be considered to be a period well in excess of 6 months.

For all subsequent periods following the initial recognition of an asset, IAS 16 permits a choice of using either the cost model or the revaluation model for valuing PP&E. HHHI has chosen to use the cost model in accordance with OEB requirements.

IAS 23 requires that borrowing costs be expensed as they are incurred unless they relate to "qualifying assets", in which case they must be capitalized if certain conditions are met. When interest is capitalized, IAS 23 requires the following steps:

- Begin capitalization when borrowing costs are incurred and expenditures and activities to develop a qualifying asset are in progress;
- Suspend capitalization when development is interrupted for extended periods; and
- Cease capitalization when a qualifying asset is ready for its intended use or sale.

Borrowing costs that are directly attributable to the acquisition, construction, or production of a qualifying asset form part of the cost of that asset. All other borrowing costs are recognized as interest expense.

The borrowing costs capitalized must reflect the weighted average of the actual borrowing costs incurred. The OEB requires the actual interest rate on the debt to be used if the related debt was acquired on an arm's length basis. If the debt is acquired on a non-arm's length basis then the interest rate used cannot exceed the Board's published rates for CWIP.

Definitions:

Qualifying asset – HHHI defines a qualifying asset as one that takes in excess of 9 months to construct or get ready for its intended use.

Conclusion:

Eligible borrowing costs will be capitalized as part of PP&E for all qualifying assets. Interest rate to be used for capitalization will be limited to the OEB's published rate for CWIP for regulatory reporting purposes.

APPENDIX OEB 1-B

PROMISSORY NOTE

Amount: $16,141,970.52 Due: December 31st, 2015

For value received, the undersigned, HALTON HILLS HYDRO INC., having offices at 43 Alice Street, Halton Hills (Acton), Ontario does hereby promise to pay to THE CORPORATION OF THE TOWN OF HALTON HILLS, or order, at the Town of Halton Hills, in the Province of Ontario, the sum of Sixteen Million One Hundred Forty-One Thousand Nine Hundred Seventy Canadian Dollars and Fifty-Two Canadian Cents (Cdn $16,141,970.52) on the last day of December, 2015.

This Promissory Note has been issued and delivered pursuant and subject to the provisions of By-laws No. 00-100 and 01-130 of The Corporation of the Town of Halton Hills upon maturity, and in replacement of the promissory note dated December 31st, 2010.

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 in accordance with the provisions of By-laws No. 00-100 and 01-130 of The Corporation of the Town of Halton Hills.

This Promissory Note may, at any time, be prepaid in full or, from time to time, in part, without notice, bonus or penalty.

Presentment, notice of dishonor, protest and notice of protest are hereby waived and the undersigned does hereby agree to remain as fully liable as if presentation, notice of dishonor, protest and notice of protest were duly made and given.

Dated and Delivered at the Town of Halton Hills, in the Province of Ontario, Canada, this 17th day of December, 2010.

HALTON HILLS HYDRO INC.

By: ______________
Arthur A. Skidmore, CMA
President & CEO

By: ______________
David J. Smelsky, CMA
Chief Financial Officer

APPENDIX OEB 1-C

Dion Durrell

SECTION E
EMPLOYER CERTIFICATION

Post-Retirement Non-Pension Benefit Plan
of Halton Hills Hydro Inc.
Actuarial Valuation as at January 1, 2009

I hereby confirm as an authorized signing officer of the administrator of the Post-Retirement Non-Pension Benefit Plan of Halton Hills Hydro Inc. that, to the best of my knowledge and belief, for the purposes of the valuation:

i) the assumptions upon which this report is based as summarized in Section C are management best estimate assumptions and are adequate and appropriate for the purposes of this valuation;

ii) the membership data summarized in Section B is accurate and complete; and

iii) the summary of Plan Provisions in Section D is an accurate and complete summary of the terms of the Plan in effect on January 1, 2009.

HALTON HILLS HYDRO INC.

10/09/30
Date

Signature

DAVID J. SMELSKY
Name

CHIEF FINANCIAL OFFICER
Title

APPENDIX OEB 1-D

9/8/2011

Halton Hills Hydro Inc.

ESTIMATED BENEFIT EXPENSE (CICA 3461)
FINAL

	Calendar Year 2009	Projected Calendar Year 2010
Discount Rate - January 1	6.25%	5.50%
Discount Rate - December 31	5.50%	5.50%
Withdrawal Rate	2.00%	2.00%
Assumed increase in Employer Contributions	actual	expected*
A. Determination of Benefit Expense		
Current Service Cost	10,525	12,876
Interest on Benefits	20,176	20,815
Expected Interest on Assets	-	-
Past Service Cost	(8,582)	(8,582)
Transitional Obligation/(Asset)	-	-
Actuarial (Gain)/Loss	(8,834)	(5,390)
Benefit Expense	13,284	19,719
B. Reconciliation of Prepaid Benefit Asset (Liability)		
Accrued Benefit Obligation (ABO) as at December 31	373,092	391,745
Assets as at December 31	-	-
Unfunded ABO	(373,092)	(391,745)
Unrecognized Loss/(Gain)	(59,292)	(53,902)
Unrecognized Past Service Cost	(51,490)	(42,909)
Prepaid Benefit Asset (Liability)	(483,875)	(488,555)
Prepaid Benefit/(Liability) as at January 1	(486,146)	(483,875)
Benefit Income/(Expense)	(13,284)	(19,719)
Contributions/Benefit Payments by the Employer	15,556	15,038
Prepaid Benefit Asset (Liability)	(483,875)	(488,555)

* based on estimated employer benefit payments for those expected to be eligible for benefits.

Projected calendar year 2010 results are provided for informational purposes only. Significant changes in 2010 such as re-negotiated benefits, increased benefit costs, or significant swings in demographics may require a full actuarial review.

9/8/2011

Halton Hills Hydro Inc.

ESTIMATED BENEFIT EXPENSE (CICA 3461)
FINAL

	Calendar Year 2009	Projected Calendar Year 2010
Discount Rate - January 1	6.25%	5.50%
Discount Rate - December 31	5.50%	5.50%
Withdrawal Rate	2.00%	2.00%
Assumed increase in Employer Contributions	actual	expected*

C. Calculation of Component Items

	Calendar Year 2009	Projected Calendar Year 2010
Calculation of the Service Cost		
- Current service cost	10,525	12,876
Interest on Benefits		
- ABO at January 1	320,062	373,092
- Current service cost	10,525	12,876
- Benefit payments	(7,778)	(7,519)
- Accrued benefits	322,809	378,449
- Interest	20,176	20,815
Expected Interest on Assets		
- Assets at January 1	-	-
- Funding	7,778	7,519
- Benefit payments	(7,778)	(7,519)
- Expected assets	-	-
- Interest	-	-
Expected ABO as at December 31		
- ABO at January 1	320,062	373,092
- Current service cost	10,525	12,876
- Interest on benefits	20,176	20,815
- Benefit payments	(15,556)	(15,038)
- Expected ABO at December 31	335,207	391,745
Expected Assets as at December 31		
- Assets at January 1	-	-
- Funding	15,556	15,038
- Interest on assets	-	-
- Benefit payments	(15,556)	(15,038)
- Expected Assets at December 31	-	-

* based on estimated employer benefit payments for those expected to be eligible for benefits.

Projected calendar year 2010 results are provided for informational purposes only. Significant changes in 2010 such as re-negotiated benefits, increased benefit costs, or significant swings in demographics may require a full actuarial review.

9/8/2011

Halton Hills Hydro Inc.

ESTIMATED BENEFIT EXPENSE (CICA 3461)
FINAL

	Calendar Year 2009	Projected Calendar Year 2010
Discount Rate - January 1	6.25%	5.50%
Discount Rate - December 31	5.50%	5.50%
Withdrawal Rate	2.00%	2.00%
Assumed increase in Employer Contributions	actual	expected*

D. Actuarial (Gain)/Loss

(Gain)/Loss on ABO as at January 1		
- Prepaid Benefit/(Liability) as at January 1	486,146	483,875
- Unamortized Past Service (Gain)/Loss	(60,072)	(51,490)
- Unamortized (Gain)/Loss	7,743	(59,292)
- Expected ABO	433,817	373,092
- Actual ABO	320,062	373,092
- Total (Gain)/Loss on ABO	(113,755)	-
(Gain)/Loss on assets as at January 1		
- Expected assets	-	-
- Actual assets	-	-
- (Gain)/Loss on assets	-	-
Total (Gain)/Loss as at January 1	(106,012)	(59,292)
10% of ABO as at January 1	32,006	37,309
Total (Gain)/Loss in excess of 10%	(74,006)	(21,983)
Expected average remaining service life (years)	12	11
Minimum Amortization for current year	(6,167)	(1,998)
Actual Amortization for current year	(8,834)	(5,390)
(Gain)/Loss on ABO at December 31 due to change in discount rate assumption		
- Expected ABO - December 31	335,207	
- Actual ABO - December 31	373,092	
- (Gain)/Loss on ABO at December 31	37,886	
Unamortized (Gain)/Loss	(59,292)	(53,902)

* based on estimated employer benefit payments for those expected to be eligible for benefits.

Projected calendar year 2010 results are provided for informational purposes only. Significant changes in 2010 such as re-negotiated benefits, increased benefit costs, or significant swings in demographics may require a full actuarial review.

APPENDIX OEB 1-E

2010 Final CDM Results: Summary

LDC: Halton Hills Hydro Inc.

This report provides an estimated allocation of 2010 OPA-funded conservation and demand management (CDM) program results for each LDC's service territory. A full, detailed report will be available in late September/early October.

The results provided in this report are in accordance with OPA practices and policies for reporting. Demand Response initiatives, for example, have been reported based on the total DR resources that were available (based on contracted nameplate capacity) rather than the actual demand reduction which occurred at the one-hour system peak in a given year.

The OPA welcomes inquiries regarding the determination of these province-wide CDM program results and/or allocation of these results to individual LDC territories. Please direct any questions to ldc.support@powerauthority.on.ca. The OPA is unable to provide any technical or regulatory advice to LDCs regarding specific treatment of these OPA-funded CDM program savings for the purposes of Lost Revenue Adjustment Mechanism or other filings by LDCs to the OEB. Such inquiries should be directed to the OEB.

All results are incremental savings in 2010 presented at the end-user level

Program	Initiative	Activity Unit	Halton Hills Hydro Inc.					Province-Wide				
			Activity Level	Net Summer Peak Demand Savings (MW)	Net Energy Savings (MWh)	Gross Summer Peak Demand Savings (MW)	Gross Energy Savings (MWh)	Activity Level	Net Summer Peak Demand Savings (MW)	Net Energy Savings (MWh)	Gross Summer Peak Demand Savings (MW)	Gross Energy Savings (MWh)
Consumer	Cool Savings Rebate	Rebates	634	0.10	151	0.22	351	136,626	20.22	31,117	46.01	72,821
Consumer	Every Kilowatt Counts Power Savings Event	Products purchased	3,390	0.01	106	0.02	228	613,248	1.70	19,100	4.00	41,300
Consumer	Great Refrigerator Roundup	Appliances	289	0.02	168	0.05	316	67,822	5.96	39,290	11.64	73,912
Consumer	***peaksaver®***	Devices installed	0	0.00	0	0.00	0	36,507	20.44	81	22.49	89
Business	Toronto Comprehensive	Projects	0	0.00	0	0.00	0	730	17.70	114,600	37.50	281,200
Business	Electricity Retrofit Incentive Program	Projects	4	0.05	285	0.10	562	1,532	19.80	111,740	37.82	220,230
Business	High Performance New Construction*	Projects	1	0.05	109	0.07	155	288	12.91	29,433	18.44	42,048
Business	Hydro Ottawa ***peaksaver®*** Small Commercial Pilot	Devices installed	0	0.00	0	0.00	0	939	0.80	2,500	0.88	2,750
Business	Multifamily Energy Efficiency Rebates	Projects	4	0.02	244	0.03	332	970	4.55	53,700	5.95	72,900
Business	***peaksaver®***	Devices installed	0	0.00	0	0.00	0	243	0.09	2	0.17	2
Business	Power Savings Blitz	Projects	225	0.20	601	0.20	603	48,274	42.20	129,200	42.60	129,500
Business, Industrial	Demand Response 3	Facilities	1	0.93	18	0.93	18	246	251.70	4,932	251.70	4,932
Business, Industrial	Loblaw & York Region Demand Response*	Facilities	0	0.11	0	0.11	0	2	29.21	0	29.21	0
Industrial	Demand Response 2	Facilities	0	0.44	514	0.44	514	3	119.00	139,100	119.00	139,100
Total				**1.9**	**2,196**	**2.2**	**3,079**		**546.3**	**674,795**	**627.4**	**1,080,783**

Program	Initiative	Allocation Methodology	Notes
Consumer	Cool Savings Rebate	Actual LDC specific results	
Consumer	Every Kilowatt Counts Power Savings Event	Measure level allocation based on 2010 Residential Energy Throughput	
Consumer	Great Refrigerator Roundup	Actual LDC specific results	
Consumer	***peaksaver®***	Actual LDC specific results	
Business	Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Ltd. service territory	
Business	Electricity Retrofit Incentive Program	LDC's respective proportion of province-wide reported gross demand savings.	
Business	High Performance New Construction	Initiative level allocation based on 2010 non-residential energy throughput by LDCs	Evaluation not yet complete; Updates expected in October/November
Business	Hydro Ottawa ***peaksaver®*** Small Commercial Pilot	Program run exclusively in Hydro Ottawa service territory	
Business	Multifamily Energy Efficiency Rebates	LDC's respective proportion of province-wide reported gross demand savings.	
Business	***peaksaver®***	Actual LDC specific results	
Business	Power Savings Blitz	LDC's respective proportion of province-wide reported gross demand savings.	
Industrial	Demand Response 2	Initiative level allocation based on 2010 non-residential energy throughput by LDCs	1) Although the program is managed internally and actual participant data is available, the small participant population can lead to participant confidentiality issues if disclosed on an actual LDC share basis.
Business, Industrial	Demand Response 3	Initiative level allocation based on 2010 non-residential energy throughput by LDCs	2) Program results are based on contracted nameplate capacity at the end of the calendar year and not actual summer coincident peak demand reduction.
Business, Industrial	Loblaw & York Region Demand Response*	Initiative level allocation based on 2010 non-residential energy throughput by LDCs	

** Initiative is not evaluated*

Appendix H

Report of the Board EB-2010-0219-Review of Electricity Distribution Cost Allocation Policy

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Ontario Energy Board

EB-2010-0219

Report of the Board

Review of Electricity Distribution Cost Allocation Policy

March 31, 2011

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Table of Contents

EXECUTIVE SUMMARY

Cost allocation policies reasonably allocate the costs of providing service to various classes of consumers and, as such, provide an important reference for establishing rates that are just and reasonable.

As indicated in the Board's September 2 letter, this consultation was intended to be limited in scope, with a more comprehensive review becoming more feasible in the next two to three years as smart meter data increases in volume and better cost allocators for the cost allocation model ("CA Model") becomes available. The focus of this consultation was therefore to determine the need for and nature of any update and refinement to the following elements of the Board's electricity distribution cost allocation policy as follows:

- To take into account the creation of the microFIT rate class;
- To refine the following specific components of the cost allocation methodology:
  - Cost allocation to unmetered loads (i.e., unmetered scattered loads, street lighting and sentinel lighting);
  - Treatment of the transformer ownership allowance;
  - Allocation of miscellaneous revenues;
  - Weighting factors for services and billing costs; and
  - Allocation of host distributor costs to embedded distributor(s).
- To review options for allocating costs to load displacement generation;
- To refine the three widest Target Ranges, which are associated with the following rate classes: General Service 50 to 4,999 kW, Street Lighting, and Sentinel Lighting; and
- To address accounting changes and the transition to International Financial Reporting Standards ("IFRS").

The Board retained the services of Elenchus Research Associates, Inc. ("Elenchus") to prepare a report that included background, options and recommendations on the above-listed matters (the "Elenchus Report"). A stakeholder meeting was held on November 18, 2010 during which participants had an opportunity to engage Elenchus in a discussion on the content of its report. On December 2, 2010, the Board received written comments on the Elenchus Report from 17 stakeholder groups.

Informed by the Elenchus Report and the stakeholder comments, and as further explained in this Report, the Board has made revisions to its policy and plans to undertake separate consultations in certain areas as follows:

MicroFIT Customers

The Board will provide an update to the default province-wide microFIT charge in November of each year. All distributors filing a cost of service application should provide information on the nine cost elements identified in the Board's EB-2009-0326

Decision and Order. This information, along with the most recent information on record for distributors that are not filing a cost of service application in that year, will be used to derive the annual microFIT charge update.

Distributors will be expected to request a change to their microFIT charge to the updated default province-wide microFIT charge as part of their annual incentive regulation application or cost of service application.

Distributors filing a cost of service application may request a distributor-specific microFIT charge but must demonstrate that the experience it has gained provides sufficient and adequate evidence for it. A microFIT administrative costs worksheet will be added to the CA Model for the purpose of collecting data from distributors for the Board's annual update to the default charge and to provide a tool for distributors wishing to apply for a distributor-specific microFIT charge.

Distributors wishing to seek approval for a distributor-specific microFIT charge may consider adjusting the weighting factors for the nine cost elements identified in the Board's EB-2009-0326 Decision and Order. Those distributors may also consider whether additional cost elements should be included in the determination of their proposed microFIT charge.

Load Displacement Generation

Additional research and further consultation on this topic will be required before a standard methodology is established. The Board believes that these issues warrant attention in the short term, and will to that end initiate a separate consultation in the near future. In the meantime, the Board will entertain applications by distributors requesting, as part of their next cost of service application, to have their existing interim standby rates declared final.

Miscellaneous Revenues

The Board expects distributors that have the relevant information to allocate the major components of miscellaneous revenues to customer classes in the same proportions as the corresponding cost drivers are allocated to customer classes. The remaining miscellaneous revenues should be allocated to the customer classes in the same proportion as composite operations, maintenance and administrative ("OM&A") expenses.

Treatment of Unmetered Load

As part of their next cost of service application, the Board expects each distributor to include a separate unmetered scattered load ("USL") class in their CA Model and on their proposed Tariff of Rates and Charges. A distributor that does not believe that it is necessary to create a separate USL rate class would have to demonstrate to the Board the benefits of not creating such a class.

There is a need to clarify some aspects of the terminology surrounding the USL and Street Lighting classes (e.g., definition of a customer, an account, a device) and the associated modeling methodology. This matter will be addressed as part of a separate consultation process that will be initiated by the Board.

Weighting Factors for Services and Billing Costs

The Board expects each distributor to assess the circumstances specific to their service area and ensure that the weighting factors they use appropriately reflect them. A new worksheet will be added to the CA Model to facilitate the customization of the weighting factors.

Transformer Ownership Allowance

The treatment of transformer ownership allowance in the CA Model will be streamlined to be consistent with the methodology outlined in Chapter 2 of the Filing Requirements for Transmission and Distribution Applications.

Allocation of Host Distributor Costs to Embedded Distributor(s)

The Board is of the view that the methodology outlined in Schedule 10.7 of the 2006 Electricity Distribution Rate ("EDR") Handbook, as updated in proceeding EB-2007-0900, provides an appropriate basis for estimating the costs to be allocated to an embedded distributor rate class.

The Board is also of the view that it is appropriate to use a threshold approach whereby any host distributor with embedded distributor(s) that exceed(s) the threshold(s) should treat its embedded distributor(s) as a separate customer class. Before determining what the threshold(s) should be, the Board will undertake further analysis. This analysis will require the collection of additional data on embedded loads from distributors and the Board will issue a letter shortly to all rate-regulated electricity distributors providing further details on this upcoming information request.

Changes to Revenue-to-Cost Ratio Ranges

The pace at which revenue-to-cost ratios should be adjusted to a Board-approved ratio should only be affected by concerns regarding its impact on any rate classes.

The Board's range for the General Service 50 to 4,999 kW and the Sentinel Lighting classes are revised to 0.8 to 1.2; all other Board ranges remain unchanged at this time. The Board's policy remains that distributors should endeavour to move their revenue-to-cost ratios closer to one if this is supported by improved cost allocations.

Accounting Changes and the Transition to IFRS

Until the changes have been finalized, it would be premature to attempt to implement IFRS-related changes to the CA Model. While no changes to the structure of the CA Model are anticipated to be required as a result of the transition to IFRS, the Board will ensure that the CA Model can accommodate an increased number of accounts in the event they are required.

Implementation

The Board's electricity distribution cost allocation policy is intended to continue to be evolutionary in nature, with the expectation that the degree of precision will continue to be enhanced as more experience is gained and additional information becomes available.

In order to implement the changes to the CA Model required from the policy changes set out in this Report, a cost allocation working group ("CA Working Group") will be established to identify and propose to Board staff the necessary revisions to the CA Model and provide input to Board staff on the development of the supporting documentation. Informed by Board staff and the CA Working Group's recommendations, the Board will issue a revised CA Model.

The revisions to the Board's cost allocation policy set out in this Report will be implemented through cost of service applications starting with the 2012 rate year. The Board's revised CA Model is not expected to be available before the April 29, 2011 filing deadline for those distributors requesting cost of service rates effective January 1, 2012. The Board notes, however, that it expects the current CA Model to be able to accommodate most of the policy changes set out in this Report. The Board anticipates that the CA Model changes will result in a more "user-friendly" platform with some additional flexibility. Accordingly, the Board expects that, in most cases, a distributor that is required to file its application before the issuance of the revised CA Model will be able to comply with the policy by applying it to the current CA Model. If necessary, a distributor in this situation may update its cost of service application with the revised CA Model once it becomes available.

1 INTRODUCTION

Cost allocation policies reasonably allocate the costs of providing service to various classes of consumers and, as such, provide an important reference for establishing rates that are just and reasonable.

On November 28, 2007, the Ontario Energy Board (the "Board") issued its *Report of the Board: Application of Cost Allocation for Electricity Distributors* (the "2007 Report"). The 2007 Report set out the Board's current policies in relation to specific cost allocation matters for electricity distributors, and represented the culmination of a consultation process that had begun several years earlier. It addressed a number of issues, most significantly the relationship between the class revenue and the class total allocated costs (the "revenue-to-cost ratio"). The 2007 Report also discussed the treatment of the monthly service charge, metering credits for the unmetered scattered load class, transformer credits for customer-owned transformers, and charges for the provision of standby power for customers with load displacement generation.

In its 2010-2013 Business Plan, the Board indicated that it would review its electricity distribution cost allocation policy and revise it as required (the "Review"). In September 2010, the Board initiated a consultation process for that purpose. All materials in relation to this consultation are available on the Board's web site.

Informed by a consultant's report and stakeholder comments, this Report sets out the Board's updated approach in relation to its electricity distribution cost allocation policy.

Implementation details relating to certain elements of the Board's approach as set out in this Report are being assigned to a Stakeholder Cost Allocation Working Group (the "CA Working Group") that will provide input to Board staff. Further detail is set out in Chapter 3 of this Report. Informed by Board staff and the CA Working Group's recommendations, a revised Cost Allocation Model (the "CA Model") will be released.

This Report sets out information on two further separate consultation processes to be initiated by the Board as well as information on the next step to establish threshold(s) above which a host distributor will be expected to establish a separate rate class for its embedded distributor(s). Except for these three matters, the revisions to the Board's cost allocation policy set out in this Report will be implemented through cost of service applications starting with the 2012 rate year. The Board's revised CA Model is not expected to be available before the April 29, 2011 filing timeline applicable to distributors requesting cost of service-based rates effective January 1, 2012. Changes to the CA Model to reflect the revised policies set out in this Report are expected to result in a more "user-friendly" platform with some additional flexibility. However, the Board anticipates that the current CA Model can accommodate most of those policy changes, and as a result most distributors should be able to comply with the revised policies by applying them to the current CA Model if their filings are due before the revised CA Model is issued. If necessary, a distributor that files its cost of service application before the revised CA Model becomes available may update its application at that time.

1.1 SCOPE OF THE REVIEW

As explained in the letter issued by the Board on September 2, 2010 (the "September letter") initiating this consultation process, this Review is limited in scope, with the potential for a more comprehensive review to be undertaken in the future.

The focus of the Review was to determine the need for and nature of any update and refinement to specific elements of the Board's electricity distribution cost allocation policy as follows:

- To take into account the creation of the microFIT rate class;
- To refine the following specific components of the cost allocation methodology:
    - Cost allocation to unmetered loads (i.e., unmetered scattered loads, street lighting and sentinel lighting);
    - Treatment of the transformer ownership allowance;
    - Allocation of miscellaneous revenues;
    - Weighting factors for services and billing costs; and
    - Allocation of host distributor costs to embedded distributor(s).
- To review options for allocating costs to load displacement generation;
- To refine the three widest Target Ranges, which are associated with the following rate classes: General Service 50 to 4,999 kW, Street Lighting, and Sentinel Lighting; and
- To address accounting changes and the transition to International Financial Reporting Standards ("IFRS").

The revisions to the Board's policy set out in this Report strike what the Board believes to be a reasonable balance between administrative burden, implementation costs and incremental precision. They also take into account the current information limitations of distributors. The Board's electricity distribution cost allocation policy is intended to continue to be evolutionary in nature, with the expectation that the degree of precision will continue to be enhanced as more experience is gained and additional information becomes available.

On October 27, 2010, the Board issued a letter to all licensed electricity distributors, transmitters and generators announcing a Renewed Regulatory Framework for Electricity ("RRF") in Ontario. That letter identified that the Board's cost allocation project, among others, fits within the RRF and that work on cost allocation would continue in co-ordination with the RRF.

1.2 THE CONSULTATION PROCESS

As indicated in the September letter, the Board retained the services of Elenchus Research Associates, Inc. ("Elenchus") to prepare a report on the cost allocation issues noted above. That report, entitled *"Cost Allocation Policy Review: Options and Preferred Alternatives"* (the "Elenchus Report"), provided background information and set out options and recommendations made by Elenchus on the matters in scope for the Review. The Elenchus Report was released for comment on October 20, 2010.

To facilitate the provision of written comments, a stakeholder meeting was held on November 18, 2010 in order to provide participants with an opportunity to engage Elenchus in a discussion on the content of the Elenchus Report. In advance of the stakeholder meeting, the Board posted participants' written questions on the Elenchus Report to ensure that the stakeholder meeting was as efficient and productive as possible.

The Board received written comments on the Elenchus Report from the 17 stakeholders listed in Appendix A to this Report. The Board has benefited from those written comments in determining the revisions to its electricity distribution cost allocation policy set out in this Report, and thanks all stakeholders for their thoughtful input.

Organization of this Report

The remainder of this Report is organized as follows: Chapter 2 addresses each of the issues in the order listed above. The discussion of each issue includes background information to provide context, Elenchus' recommendation(s) and a summary of the input received from stakeholders, and concludes with a statement of the Board's approach. Chapter 3 then discusses next steps.

2 STAKEHOLDER COMMENTS AND THE BOARD'S APPROACH

This Chapter is divided into sections that address individually each of the nine issues listed in the Board's September 2, 2010 letter initiating this consultation process. The initial "General Comments" section addresses comments of a general or over-arching nature that were made by stakeholders during the course of the consultation.

2.1 GENERAL COMMENTS

In addition to the detailed comments that stakeholders provided on each policy issue being reviewed in this consultation, several also warned in their comments that the benefits of achieving increased detail and precision in cost allocation studies do not always justify the additional cost. The Board acknowledges this note of caution, and has remained cognizant of the need to maintain some degree of flexibility in recognition of the different circumstances of individual distributors. Among other things, this consideration has prompted the Board to make provision for the use of default values rather than distributor-specific values refinements that may be costly to derive.

This flexibility, however, is not intended to encourage the use of default values by distributors that can reasonably be expected to undertake the incremental effort to more accurately allocate costs to their customer classes. As several stakeholders observed, default values should not be the preferred option in the CA Model and should only be used where they are appropriate to the distributor's actual circumstances or where the distributor can demonstrate that the anticipated benefits of increased precision would not be commensurate with the cost of producing distributor-specific values.

2.2 TREATMENT OF MICROFIT CUSTOMERS

2.2.1 BACKGROUND

The current rate treatment for microFIT generators resulted from the proceeding that the Board initiated on September 21, 2009 on its own motion in order to determine "a just and reasonable rate to be charged by an electricity distributor for the recovery of costs associated with an embedded generator account having a nameplate capacity of 10 kW or less … that meets the eligibility requirement of the OPA's microFIT program" (EB-2009-0326).

In a decision released February 23, 2010[1], the Board's approach was that the costs to be included in determining the microFIT charge should be strictly related to the administrative activities associated with the customer and would not include any costs related to system operation.

The Board determined that those costs should be recovered solely through a fixed monthly service charge and that a single province-wide charge should be established

[1] EB-2009-0326 Decision and Order, issued February 23, 2010.

for all distributors for the time being. The province-wide charge of $5.25 per month was established on the basis of the customer weighted average of nine specific cost elements using data from 62 distributors.[2]

2.2.2 RECOMMENDATION OF ELENCHUS

The Elenchus Report recommended that distributors should be allowed to establish and seek approval for their own individual microFIT charge to better reflect the specific cost causality for the individual distributors. To facilitate the determination of the distributor-specific microFIT charge, Elenchus recommended that a separate sheet identifying the nine cost elements used by the Board to establish the province-wide monthly microFIT charge be added to the CA Model. Elenchus was of the view, however, that the establishment of a separate customer class in the CA Model was not needed.

Elenchus also recommended that the nine cost elements used by the Board in establishing the province-wide charge as described above could continue to be used by distributors that did not have sufficient experience with microFIT customers to support a distributor-specific charge.

2.2.3 STAKEHOLDER COMMENTS

Continued use of the current nine cost elements

Most stakeholders that submitted written comments supported the Elenchus recommendation to continue to use the nine cost elements identified by the Board in proceeding EB-2009-0326 to determine the cost of serving microFIT customers. The stakeholders were of the view that not enough time has elapsed to enable distributors to gain sufficient experience or a better understanding of the costs incurred in serving microFIT customers to justify changing the cost elements used at this time.

The only participant proposing a change was the Vulnerable Energy Consumers Coalition (“VECC”). VECC suggested that the Board should reconsider the account elements that are included in the determination of the province-wide charge and specifically suggested that interest and net income expenses related to General Plant assigned to Meters should be added to the cost elements used to determine the microFIT charge.

Distributor-specific microFIT charge

Stakeholders were also generally supportive of the recommendation to allow distributors to establish and seek approval of their own microFIT charge since distributor-specific charges would be more reflective of the distributor’s own costs and would better reflect cost causality principles. However, views were diverse concerning the timing of the move to distributor-specific charges.

[2] Rate Order dated March 17, 2010 (EB-2009-0326).

The Association of Major Power Consumers in Ontario ("AMPCO") and distributors supported allowing distributor-specific charges at this time. However, the Electricity Distributors Association ("EDA") and London Property Management Association ("LPMA") suggested that the province-wide approach be continued for now. In their view, the move to distributor-specific charges should be deferred until distributors have gained more experience in connecting microFIT generators and identifying associated costs. More experience is required to determine whether actual costs differ enough across distributors to warrant distributor-specific rates.

Two representatives of ratepayers, School Energy Coalition ("SEC") and VECC, did not support the Elenchus recommendation. SEC was of the view that distributors should not be allowed to establish their own rate because to do otherwise would limit the uptake of microFIT in specific geographic areas and may result in additional costs incurred by the distributor that would not be cost justified. VECC's view is that it should not be left up to the distributors to decide whether to use their own microFIT charge. VECC suggested that the Board establish a range around the rate and that the distributor only be allowed to establish and seek approval of their own rate if they fall outside the range. VECC noted that the consultant's recommendation about adding a separate sheet to the CA Model to determine the distributor's own microFIT charge would facilitate this approach.

Separate microFIT class for cost allocation purposes

The creation of a separate customer class for microFIT in the CA Model was supported by LPMA and Oakville Hydro as this would enable distributors to reflect their own microFIT charge and would provide for consistent treatment by distributors.

VECC did not support the creation of a separate customer class for microFIT unless the Board's objective is to have distributor specific microFIT charges. VECC is of the view that distributors and the Board need to gain more experience with microFIT connections before creating a separate customer class. VECC also stated that the CA Model is used to determine if rate adjustments are required to better align rates with costs and for the province-wide microFIT charge this can be accomplished by the addition of a separate sheet to the CA Model, as recommended by Elenchus.

Weighting factors for microFIT customers

Those stakeholders that commented on the weighting factors used to determine distributor-specific costs generally recognized that the weighting factors would be one of the factors that would cause microFIT cost to differ across distributors.

AMPCO indicated that allowing distributors to modify the billing weighting factor for microFIT would be necessary to allow distributors to properly allocate the costs imposed by microFIT customers including transitional costs to their customers. In AMPCO's view, the weighting factors used should reveal the extent to which cost differences are due to transitional technical issues versus basic differences between microFIT and residential billing service. AMPCO was concerned that, if transitional costs are not allocated properly, the true cost of microFIT would not be known, customer cross-subsidization would result and these costs would not be addressed and reduced over time.

Updating province-wide average microFIT costs

The EDA and Hydro One Networks ("Hydro One") suggested that the Board undertake an annual update to the microFIT charge to reflect the experience gained by distributors with microFIT connections, while SEC was of the view that no change to the microFIT charge is required at this time. SEC stated that, with more experience with microFIT data and smart meter data in the next few years, the Board would then have the information it needs to decide if changes are required for the microFIT charge.

LPMA noted that the current microFIT charge is based on a weighted average of current cost experiences of distributors so, if a distributor with a relatively large percentage of microFIT customers establishes and seeks approval for their own rate, the provincial microFIT charge for the remaining customers could become more volatile, reflecting the removal of costs from this distributor. To avoid this volatility, it would be necessary to base the default province-wide charge on the cost of all distributors, including those that adopt their own distributor-specific rate.

MicroFIT charge as miscellaneous revenue

The Coalition of Large Distributors ("CLD") suggested that the revenue from microFIT charges should be treated as miscellaneous revenues and Hydro One asked the Board to confirm this treatment.

2.2.4 THE BOARD'S APPROACH

The Board's approach, as set out below, takes into account that the Board's view that the rate at which distributors are gaining experience with the administrative costs associated with microFIT customers varies considerably across distributors. Accordingly and as further explained below, the Board will maintain and update annually the default province-wide microFIT charge, but is also prepared to consider applications for distributor-specific microFIT charges.

Continued use of the current nine cost elements

The Board continues to consider the approach set out in its EB-2009-0326 Decision and Order to be an appropriate basis for establishing the administrative or service charge to be paid to distributors for microFIT connections. Specifically, the costs to be recovered through the microFIT charge should be strictly related to the administrative activities associated with this class of customer and should not include any system operation related costs. These microFIT administrative costs will continue to be based on the nine cost elements identified in the EB-2009-0326 Decision and Order and supported by most stakeholders, but will now be refined to also include the interest and net income expenses related to General Plant assigned to Meters as suggested by VECC. Consistent with the EB-2009-0326 Decision and Order, administrative or service costs associated with microFIT customers should continue to be recovered solely through a fixed monthly charge.

A microFIT administrative costs worksheet will be added to the CA Model. This worksheet will serve to collect data used by the Board to calculate an annual update to the default province-wide microFIT charge. The worksheet will also inform the distributor of what its distributor-specific microFIT charge would be based on using the methodology and the nine cost elements noted above, which will help the distributor assess whether or not there would be a large difference from the default province-wide microFIT charge. Additional information on the requirements associated with applying for a distributor-specific microFIT charge is provided further below.

All distributors are expected to include the calculation of their microFIT administrative costs, as will be contained in the revised CA Model, even if they apply to use the default province-wide charge as the basis for charging any microFIT customers they might have. This information will facilitate the Board's update of the default province-wide charge, and also provide a basis on which the Board can assess whether variations would support distributor-specific charges. For distributors that need to file their cost of service applications prior to the issuance of the revised CA Model, a separate sheet should be provided showing their administrative costs for the nine cost elements identified in the EB-2009-0326 Decision and Order.

In calculating the annual update to the default province-wide microFIT charge, the Board will use the data collected on the microFIT worksheet from all distributors filing a cost of service application, along with the most recent information on record for distributors that are not filing a cost of service application in that year. The costs for distributors that have a Board-approved distributor-specific microFIT charge will also be included as part of these data.

The updated province-wide charge will be communicated by the Board in November of each year. Distributors that do not have a distributor-specific microFIT charge will be expected to request to change their microFIT charge to the updated default province-wide microFIT charge as part of their annual incentive regulation application or cost of service application. Accordingly, a Board-approved change to the default province-wide microFIT charge will come into effect either on January 1st or May 1st of the following calendar year, depending on whether the distributor's rate year starts on January 1st or May 1st.

Distributor-specific microFIT charge

The EB-2009-0326 Decision and Order indicated that the single province-wide charge was established as a foundation and that, over time and with empirical information regarding the costs associated with the microFIT class, the Board would be in a better position to consider the effectiveness of the province-wide charge. The Board also stated that the Board may consider moving to utility-specific charges at some point in the future if it was determined that the actual costs for microFIT customers are significantly disparate across distributors.

The Board notes that two ratepayer representatives were opposed to allowing distributor-specific microFIT charges and, among those that were supportive of a distributor-specific approach, views were diverse in relation to when distributor-specific charges should commence to be allowed.

The Board believes that the rate at which distributors are gaining experience with the administrative costs associated with microFIT customers varies considerably across distributors. While the response to the microFIT program has been significant, experience to date remains limited for many distributors. As such, the Board will maintain a province-wide microFIT charge as noted in the previous section.

The Board does, however, anticipate that most distributors will gain further experience in serving microFIT customers over the coming years. The Board is therefore prepared to consider applications for distributor-specific microFIT charges. Any distributor that applies for a distributor-specific charge will be required to demonstrate that the experience it has gained provides sufficient and adequate evidence for it.

The Board recognizes that, as distributors gain experience with microFIT connections, distributors wishing to seek approval for a distributor-specific microFIT charge may identify additional cost elements that should be included in the determination of that charge. Proposed additions could be reflected in the microFIT administrative costs worksheet filed with the Board in a cost of service proceeding, and will be considered at that time.

Weighting factors for distributor-specific microFIT charge

The calculation of the current province-wide microFIT monthly charge resulting from the EB-2009-0326 proceeding is based on nine cost elements, all of which can be described as "customer-related" costs. The microFIT class mimics the Residential class in terms of weighting within the nine cost elements. Hence, the costs attributable to the nine cost elements for the Residential class were used as a proxy for the microFIT class. Going forward, if a distributor feels that the weighting factor applicable to the microFIT class should be different from the Residential class within any of the nine cost elements, the distributor may propose a different weighting in the microFIT administrative costs worksheet that is to be added to the CA Model.

Separate microFIT class for cost allocation purposes

The Board notes that it would be appropriate to establish a separate microFIT customer class in the CA Model if the intention were to allocate common costs to the microFIT class in the same manner as those costs are allocated to other customer classes.

However, the Board does not consider it necessary to establish a separate microFIT class within the CA Model given that the costs being allocated to microFIT customers are, for the time being, limited to administrative costs. The microFIT charge is limited in scope and, as mentioned above, the addition of a separate worksheet in the CA Model should provide the flexibility a distributor requires to determine its proposed distributor-specific microFIT charge, if it wishes to make such an application.

MicroFIT charge as miscellaneous revenue

The Board confirms that revenues collected through the microFIT charge are to be treated by distributors as miscellaneous revenue.

2.3 TREATMENT OF LOAD DISPLACEMENT GENERATION

2.3.1 DESCRIPTION OF ISSUE

Some distributors' customers have their own generation facilities that supply all or part of the customer's electricity needs. At times when the customer-owned generation is unavailable, those needs or a part thereof have to be met by the distributor. The costs incurred by distributors in having facilities ready to supply these customers should be recovered from the same customers, and the rate used for that purpose is called a "standby rate".

In its March 21, 2006 Decision in EB-2005-0529, the Board declared "all existing and proposed standby rates" interim pending further review of the associated principles. Currently, 16 distributors have standby rates. For 15 of these distributors, the standby rates remain interim, whereas one distributor has had its interim standby rates declared final. [3]

In 2007, the Board initiated a consultation on distributed generation that included consideration of the development of a standard methodology for quantifying the benefits of distributed generation (EB-2007-0630). Power Advisory LLC was retained by the Board to prepare a report on the subject, and that report was released for stakeholder comment. By letter dated January 29, 2008, the Board informed interested participants that the issues of rate classification and standby rates for load displacement generation were being moved to the Rate Design for Electricity Distributors consultation (EB-2007-0031). By letter dated April 16, 2009, the Board informed participants in EB-2007-0031 that it had decided "to defer the completion of the rate design project."

[3] Enersource 2008 Distribution Rates, EB-2007-0706, April 18, 2008.

2.3.2 RECOMMENDATION OF ELENCHUS

Elenchus recommended the following:

- Standby rates should be established for new load displacement generation above 500 kW. This threshold was chosen to reflect the level that could represent significant load for distributors.
- In determining new standby rates, the costs imposed on distributors by customers with load displacement generation should be determined by undertaking a customer-specific avoided cost analysis. As a simplified approach, values for default avoided costs could be used in lieu of a specific customer analysis. Similarly, a simplified approach should be used to establish the benefits that load displacement generation may provide. A value of 5% should be used to reflect these benefits, and be deducted from the allocated costs.
- Existing standby rates should be allowed on an interim basis until more research has been conducted on the standby rates issue, including rate design issues. Distributors that currently have interim standby rates should be allowed to choose whether to establish new standby rates based on an avoided cost analysis or use a default value for avoided costs.
- A separate customer class should be created for customers with load displacement generation in circumstances where the load represents a significant load for the distributor. A threshold of more than 10% of the distributor's total sales was suggested for that purpose. The costs allocated to the separate customer class would then be reduced by an estimate of the benefit of load displacement generation in order to determine the standby rates.
- For rate design purposes, if the generator is above a certain size, (e.g., above 5 MW), then the rated capacity of the generator should be used and not the customer's demand profile, as this size of generation would be a significant load for distributors.

2.3.3 STAKEHOLDER COMMENTS

Although several stakeholders (LPMA, EnWin, Oakville Hydro and PWU) supported Elenchus' recommendation to establish standby rates for new load displacement generation above 500 kW in principle, the prevailing view is that there is insufficient information and analysis to support Elenchus' recommendations or any alternate approach to allocating costs to load displacement generation and establishing standby rates. There is widespread concern that the issues that need to be carefully examined in order to resolve the issue go well beyond the scope of this Review.

Oakville Hydro, for example, suggested that standby rates should be established for new load displacement generation above a certain size. But it believes the determination of that size merits further study.

VECC observed that Elenchus did not undertake any analysis to determine the appropriateness of "costing" Standby Service using the Board approved avoided cost estimate which are based on estimates developed by Hydro One in 2005 for customers supplied from its system and were characterized as "preliminary in nature". VECC has been long concerned about continuing use of these estimates as representative avoided costs for all distributors and urges the Board not to expand the use of questionable and dated estimates. It is therefore VECC's view that it would be inappropriate for the Board to adopt a new approach to setting standby rates as part of a cost allocation review. Setting new standby rates should be part of the Board's rate design initiative undertaken at a future date.

CLD expressed a similar view recommending that the CA Model should not be changed at the present time and that the issue of standby rates would be better addressed via a consultation on rate design for embedded generation to be re-convened by the Board.

In a similar vein, AMPCO stated that the requirements to provide standby power equal to the generator output is not based on any research and does not take into consideration the customer's facilities configuration and operating characteristics. This assumption, AMPCO stated, is unfair to the customer if the generation project reduces costs for distributors, since customers would still have to pay for distribution as though generation did not exist. AMPCO also noted that the Ontario Government policy is to encourage customer owned Distributed Generation that provides process heat and that if a formula is applied to calculate standby rates, it could result in the inability of the best projects to realize the benefits of a reduced demand on distribution system. Given these concerns, the appropriate way to address the issue in AMPCO's view is to undertake a separate review mechanism and consultation. This review should consider a reduction in the standby rate for load displacement projects where customers do not require the full standby capacity. This could be achieved as a joint review of standby requirements by the distributors and the customer.

LPMA also suggested that the Board should initiate a more comprehensive review of standby rates that encompasses both cost allocation and rate design options, along with a review of other jurisdictions. The review should look at issues such as firm or interruptible service, contracted demand levels versus generation capacity and the system planning implications of different scenarios. In LPMA's view, the key principle in determining standby rates is cost causality; standby customers should be responsible for the costs they impose on the distribution system and that other distribution customers should not subsidize customers who own generation behind their meter.

SEC stated that the absence of available research on what other jurisdictions have done to assess costs/benefits of load displacement generation results in a major weakness in Elenchus' recommendation, because according to SEC, the costs/benefits of load displacement generation are a common concern of distributors around world, and a lot of work has been done, particularly in the U.S. SEC says the recommendation assumed that costs/benefits would be calculated on an incremental basis, although no justification has been provided for treating these customers as incremental. SEC also believed it is not clear why the Board would consider avoided costs developed for CDM purposes to be appropriate for load displacement generation, when there is no information on whether generator-specific benefit analyses are worth the cost of carrying them out, or even what that costs might be.

Given these concerns, CLD suggested that if the Board directs distributors to establish standby rates based on Elenchus' methodology, this should only apply to new load displacement generation.

Benefit valuation

Most stakeholders consider it inappropriate to adopt an arbitrary valuation for the system benefits of load displacement generation, be it 5% as recommended by Elenchus or any other value. Only the Power Workers' Union ("PWU") supported adopting the 5% value as a placeholder until more analysis can be conducted. Most others are concerned that the benefits of load displacement generation have not been adequately studied or quantified.

Given the absence of supporting analysis, EDA is concerned that most of distributed generation load is not dispatchable by distributors and would thus not be of any direct benefit. EDA stated that distributors incur costs for keeping distribution system facilities ready to deliver the customers' electricity requirements and those costs have to be recovered from the customers responsible for causing them. If a customer wants to avoid paying for distribution facilities by installing load displacement generation, that customer should give up any claim to any capacity effectively reserved to serve them, otherwise other customer classes end up subsidizing the load displacement generation customer. EDA believed that distribution system costs remain the same regardless of whether a generator is connected or not and that capacity cannot be 'un-built' in response to the installation of load displacement generation.

SEC wondered, if existing standby rates are reflective of cost causality, why would the Board change them and, if they are not cost reflective, why would the Board allow them to be continued. SEC stated that in neither case does it appear the matter should be at the discretion of individual distributors.

VECC stated that Elenchus' recommendations were not based on any work undertaken by Board staff or Elenchus during any earlier consultations and that Elenchus did not acknowledge the difficulties these earlier works had in determining the appropriate benefits to be attributed to Distributed Generation. VECC noted that once a factor is adopted by a regulator it is viewed as having credibility and any change frequently requires justification. As a result, VECC is of the view that it is important that such factors have at least some basis in reality before being adopted.

Use of avoided cost for standby rates

No stakeholder other than PWU was supportive of Elenchus' recommendation to use customer-specific avoided costs as a basis for determining new standby rates. There was also significant concern with adopting an "arbitrary" simplified approach, leaving no available option other than undertaking a further process to investigate the relevant issues more fully.

EDA indicated that it is impractical to consider, on a case by case basis, any reduction in new capital investment in distribution or transmission assets due to each load displacement generation. Reinforcing that point, North Bay Hydro ("NBH") expressed the view that customers installing load displacement generation might have facilities serviced by different distributors.

AMPCO believed this is unfair to some customers with generation and also perhaps in some cases to distributors. AMPCO feels that default values can act as a disincentive to developing load displacement generation that constitutes a "highest and best use" of energy resources.

In supporting the recommendation, PWU suggested that each distributor be given the option to determine an appropriate value for avoided costs, benefits and the reduction to allocated costs based on management judgement and expertise. PWU believed that, in the absence of quantitative analysis, allowing this flexibility would help to ensure the use of values that better reflect the unique circumstances of the distributor. If a distributor opted to use its own values instead of default values, the distributor should be required to justify those values to Board.

NBH and Cornerstone Hydro Electric Concepts Association ("CHEC") each suggested that, if the consultant's recommended approach is adopted, a detailed explanation with good examples should be provided to show how to conduct a specific customer avoided costs analysis and how to incorporate the results of the analysis in the CA Model. If default avoided cost values are used, the source of default values should be established by Board.

Cost allocation versus rate design issues

A number of stakeholders raised issues that they considered integral to any resolution of the matter, although they are beyond the scope of the Cost Allocation review.

VECC noted that the recommendation deals primarily with how rates for standby service should be established and not how they should be treated in cost allocation. VECC stated that the most relevant cost allocation issue is whether standby service should be included as a separate customer class in the CA Model. If a separate class, according to VECC, the options are: (a) standby service as a separate service class from the services provided to service load net of the customer owned generation but using the standard allocation factors as per the CA Model; or (b) establishing a separate service directly assigning costs. If not a separate class, VECC raised the issue of how should revenue from standby service be allocated to customer classes. With respect to the relevant cost allocation issues noted by VECC, VECC stated that either the Board have the consultant or Board staff fully evaluate the relevant options and recommend an approach for comment or the Board establish a work group that should focus strictly on incorporating a standby class into the CA Model. If included in the CA Model, the resulting revenue-to-cost ratios should not be used to adjust existing or new standby rates. Rather, the methodology used to establish interim rates would continue until an appropriate basis for setting standby rates is established.

Existing interim rates

With respect to Elenchus` recommendation that existing standby rates continue to be allowed on an interim basis, the EDA recommended that the Board should continue to apply approved standby rates on an interim basis, until a complete analysis, including rate design options, is carried out.

On the other hand, EnWin Utilities ("EnWin") had concerns with the interim status of standby rates. EnWin stated that interim rates represent a significant concern because they are exempt from the rules pertaining to retroactivity. That means distributors could be forced to retroactively adjust with customers, years of standby rates against any final rates that may be approved by Board. Continued use of interim rates puts distributors in a difficult position from a risk management perspective. Distributors have to choose between financial under-recovery or the regulatory, operational and financial burden of "truing up" potentially years of rates that have been applied due to lack of regulatory clarity. Distributors, according to EnWin, also face the risk of spending substantial resources to implement an interim rate that may be replaced in near future.

2.3.4 THE BOARD'S APPROACH

The Board agrees with the prevailing view of the stakeholders that resolution of the load displacement generation issues requires additional research and consultation.

The Board therefore does not consider it appropriate to develop a cost allocation methodology for load displacement generation at this time. However, the Board believes that these issues warrant attention in the short term, and will to that end initiate a separate consultation in the near future.

In the meantime, the current interim standby rates will remain in place. The Board acknowledges the concerns regarding regulatory uncertainty that were most forcefully expressed by EnWin in relation to the interim nature of the standby rates, and will therefore entertain applications by distributors to have those rates made final as part of their next cost of service application.

2.4 *Treatment of Miscellaneous Revenues*

2.4.1 Description of Issue

Distributors collect miscellaneous revenues from their customers in addition to collecting revenues tied to delivery.

Miscellaneous revenues are comprised of 30 different accounts. However, based on data from the 2006 Electricity Distribution Rates process, 92% of miscellaneous revenues are typically accounted for by only four accounts (late payment charges, account set up & changes, collection charges and access to poles).

2.4.2 Recommendation of Elenchus

Elenchus recommended that the four major components of miscellaneous revenues should be allocated to customer classes in a manner that follows the allocation of the corresponding costs. The four major components identified by Elenchus were:

1. Late Payment charges;
2. Account set up charge/change of occupancy charge (plus credit agency costs if applicable);
3. Specific Charge for Access to the Power Poles $/pole/year; and
4. Collection of account charge - no disconnection.

The remaining miscellaneous revenues should be allocated to the customer classes in the same proportion as composite operations, maintenance and administrative ("OM&A") expenses. Miscellaneous revenues and related costs should be included in the determination of revenue-to-cost ratios within the CA Model.

2.4.3 Stakeholder comments

All stakeholders acknowledged that refinements could be made to the allocation of miscellaneous revenues in the CA Model so that it would better reflect cost causality principles. However, there was disagreement over the practicality of implementing these changes and a number of specific suggestions were made related to the treatment of specific miscellaneous revenue accounts.

For example, VECC stated that while Elenchus recommendation sets out appropriate principles for allocating miscellaneous revenues, further work would be required before these principles can be properly reflected in the CA Model. VECC suggested that if the Board wishes to move in this direction, then either Board staff should prepare a proposal that could be commented on, or the Board should establish a small work group of interested parties to develop detailed recommendations on how the CA Model could be changed in the near term.

Issues of practicality

CHEC stated that allocating miscellaneous revenues to rate classes in a manner similar to the allocation of corresponding costs is not doable because cost details are not available for late payment charges, account set-up charges and collection of account charge. Similarly, NBH and CLD were concerned that the data required to implement Elenchus recommendation are not kept by distributors. Significant effort would be required to determine these costs and the additional administrative costs would not be justified by the added allocation precision; hence, it was the view of NBH and CLD that the current treatment of miscellaneous revenues in the CA Model should not be changed. Similarly, SEC was concerned that the additional costs associated with greater precision may not be justified by the results, particularly since Elenchus did not review whether there is any other, more accessible cost driver that could be used to avoid the additional work.

CHEC suggested that an analysis should be completed to determine whether this change would have a material impact on revenue-to-cost ratios. If no material change results, then no change should be made.

AMPCO, LPMA, EnWin, Oakville Hydro and PWU supported Elenchus` recommendation. However, LPMA only supported Elenchus` recommendation as an interim measure in the evolution of the allocation of miscellaneous revenues. LPMA was of the view that the end-state should be similar to the allocation of miscellaneous revenues in the natural gas industry. Oakville Hydro suggested that distributors be permitted to define which accounts are to be considered major components and to define the OM&A accounts where the costs incurred to provide these services reside.

Allocation of remaining miscellaneous revenue accounts

No stakeholder opposed the recommendation that the remaining miscellaneous revenues be allocated to customer classes in the same proportion as composite OM&A.

Inclusion in revenue-to-cost ratios

There was no stakeholder opposition to the recommendation that miscellaneous revenues be included in the determination of revenue-to-cost ratios in the CA Model.

Comments on the treatment of specific miscellaneous revenue accounts

VECC observed that the Elenchus` approach requires that both cost and revenues associated with major sources be properly attributed to customer classes. For the major sources of miscellaneous revenues derived from customers, revenues by customer class should be readily available and, ideally, the costs of providing associated services would similarly be allocated to each customer class. VECC stated that the current model generally uses “weighted number of bills” to allocate costs associated with billing to and collecting from customer classes. The exception is bad debt expense which is allocated on the basis of bad debt history by class. Implementation of Elenchus` recommendation would require "costs" associated with these activities be more precisely identified and then allocated in a manner that reflected activity by customer class. In the alternative, VECC suggested that revenues should be assigned to customer classes based on history/forecast of these revenues by customer class, on the assumption that current cost allocation properly assigns "costs" to customer classes.

VECC suggested that for miscellaneous revenues not derived from customers (e.g., Service Charges for Access to Power Poles), revenues should be assigned to customer classes in a manner similar to how the costs associated with the assets involved were allocated to classes. Following this principle, revenue from pole access fees would be allocated to classes in accordance with how the cost of the poles (Account #1830) is allocated to classes. VECC was of the view that this allocation could be refined to reflect distributor specific information as to whether poles involved were associated with distributors` bulk, primary and/or secondary delivery systems.

Oakville Hydro suggested that miscellaneous revenues should be excluded from the calculation of the following costs: Customer Unit Cost per month - Avoided Cost; the Customer Unit Cost per month - Directly Related; the Customer Unit Cost per month - Minimum System with PLCC Adjustment on tab O2, Fixed Charge; and the Floor Ceiling of the CA Model. Oakville Hydro was of the opinion that allocation of miscellaneous revenues for purpose of calculating floor and ceiling is inappropriate unless those revenues have a direct relationship to the customer class.

Hydro One was of the view that the best approach is the direct allocation of miscellaneous revenues where possible. Oakville Hydro similarly suggested that the CA Model should permit the direct allocation of miscellaneous revenues.

2.4.4 THE BOARD'S APPROACH

To ensure that customers are treated fairly, the allocation of revenues to customer classes for the provision of the services should be the same as the allocation of the underlying costs. This is in keeping with an allocation that is based on the cost causality principle. The Board therefore expects distributors to allocate the major components of miscellaneous revenues to customer classes in the same proportion as the corresponding cost drivers are allocated to customer classes, to the extent that the distributor has the relevant information.

Those major components are, as identified from 2006 information and confirmed by Elenchus, namely: late payment charges, account set up & changes, collection charges, and access to poles. The remaining miscellaneous revenues should be allocated to the customer classes in the same proportion as composite OM&A.

Where a distributor does not have the information necessary to enable it to determine the associated costs by rate class for the major components of miscellaneous revenues, the distributor may allocate those miscellaneous revenues to customer classes using composite OM&A as the allocator. However, the Board expects such distributors to explain why the information is not available and to provide a plan describing how they intend to gather the data and identifying when the data will be available.

As is currently the case, miscellaneous revenues and related costs should be included in the determination of revenue-to-cost ratios.

2.5 Treatment of Unmetered Loads

2.5.1 Description of issue

Unmetered Load refers to three customer classes - Street Lighting, Sentinel Lighting and unmetered scattered load ("USL") - that are not metered because they consist of relatively small dispersed loads with electricity consumption that is predictable and can be determined based on the characteristics of the connected load (for example, light size or cable TV amplifier rating). In the current CA Model, different allocation factors are used for these customer classes and metering costs are not allocated to them.

If USL is not treated as a separate customer class by a distributor, it is included in the General Service ("GS") below 50 kW customer class.

The fact that these classes are not metered creates unique issues in ensuring that the CA Model appropriately allocates costs in a manner that is reflective of the cost causality principle.

2.5.2 Recommendation of Elenchus

The Elenchus Report recommended adding a separate sheet to the CA Model that would include the default weighting factor values used for these types of customers and would clearly indicate to distributors the option of proposing their own weighting factor values in place of the default values. A description of how the default weighting factor values were developed would be included to assist distributors in developing their own values.

For distributors that do not have a separate customer class for USL, the distributor should be required to demonstrate that the revenue-to-cost ratio for these types of customers would still be within the Board's recommended range for USL. Elenchus is of the view that there is no need to direct distributors to create a separate customer class for USL.

2.5.3 Stakeholder comments

Many stakeholders were of the view that the recommendations of Elenchus do not go far enough to adequately address existing concerns related to the unmetered classes. Many believe a separate USL class is required and, if a separate class is not established, a more refined approach to allocating costs is needed. Many stakeholders also believe that the allocation of costs to street lighting requires significant additional work in order to develop a more appropriate approach to determining the causal costs of street lighting.

USL as a separate class

The treatment of USL as a separate customer class in the CA Model was recommended by Rogers Cable, LPMA and AMPCO.

LPMA suggests that transparency is lost when distributors include USL with the GS < 50 kW class. In those cases, the distributor should be required to calculate the appropriate credit to the appropriate subset of GS < 50 kW customers while at the same time ensuring that the revenue-to-cost ratios for this subset of customers falls within the Board's target range for the USL rate class.

Rogers Cable believes that the Elenchus Report does not provide adequate reasons for its not adopting a separate class, especially since the information before the Board in the EB-2007-0031, Rate Design for Recovery of Electricity Distribution Costs consultation shows this is not the preferred alternative. The presumption in the Elenchus` report that a metering credit alone will ensure the fairness of rates oversimplifies the issue in Rogers' view. For example, a metering credit does not take into account any differences in per-connection billing, collection, call centre and other customer service costs and differences in load factor that may exist between the USL customers and metered customers. These differences, when taken into account in the CA Model, may result in a revenue-to-cost ratio outside the acceptable range, even after the application of a metering credit. Creation of a separate class would allow the USL revenue-to-cost ratio to be adjusted and a separate rate structure to be created without changing the rate structure applicable to metered customers. Rogers Cable also stated that regardless of whether a separate class for USL is implemented at this time, the record on this issue before the Board indicated that USL customers have generally overpaid relative to the costs to serve them, and have generally experienced rates that vary significantly between distribution territories.

AMPCO said the Board may wish to consider establishing a separate class or classes for USLs, with class definitions and guidance on matters such as consumption limits for unmetered connections, bill aggregation, etc. AMPCO's view was that the question of how best to allocate costs for USL has been a significant issue for the Board for several years. AMPCO stated that the issue is aggravated by calculated revenue-to-cost ratios for some USLs that seem to suggest that this class is being significantly subsidised and by concerns of the CATV industry that they may be over-charged for service in some instances.

SEC noted that while the Elenchus` report recommends that USL need not have a separate rate class, Elenchus proposes that calculation of the revenue-to-cost ratio for those customers should still be required, as if it were a separate rate class. SEC agreed that calculating the USL revenue-to-cost ratio is appropriate. What SEC was not able to determine is how doing that without having a separate rate class would save money or other resources. It would seem to SEC that this is an unnecessary complication in a cost allocation and rate design system that already has enough complications.

In SEC's view, if it is sufficiently important to match USL costs to rates, then the Board already has a way to do that and it is to establish a rate class. However, the value of establishing a completely different approach for USL is not clear to SEC. Further, continued SEC, one can foresee that if calculating the revenue-to-cost ratio for this subclass is considered appropriate, then there will be other customer groups with special situations (schools, for example, with multiple similar locations for a single customer) who will legitimately ask for the same treatment.

Meter related costs if USL not a separate class

VECC noted that in those circumstances where USL is not a separate class but is included as part of the GS<50 kW class and provided a credit to recognize the meter/meter reading savings, the treatment should be as follows:

- The cost allocation to the GS<50 kW class should recognize that only a subset of the customers/connections have meters and require meter reading.
- The "cost" of providing the USL credit should be allocated to the other customers in the class (similar to the treatment afforded the TOA).

Should the Board decide not to proceed with the implementation of a separate USL rate class at this time, Rogers Cable concurred with Elenchus` recommendation that a revenue-to-cost ratio for USL be developed, and that distributors be required to demonstrate that the USL revenue-to-cost ratio is within the Board's target range. This is consistent with the Board's decision in relation to Hydro One's 2010-2011 distribution rates, as referred to in the consultant's report.

Rogers Cable said this will require all distributors, including those that do not already have a separate USL rate class, to isolate USL costs in their CA Models by running the CA Model with a separate class for USL. As a result, USL customers will be better able to assess and advocate. In addition, the Board will be better able to determine the fairness of USL rates.

Weighting factors

EnWin, CLD, PWU, LPMA and Rogers Cable supported Elenchus` recommendation to include a separate sheet in the model with the default values and explaining that distributors can use their own values since it would lead to more consistency across the province and reduce any subsidization between the USL class and other customers.

In LPMA's view, there appeared to be substantial confusion and differences across distributors in the use of or the calculation of the services weighting factor as well as in the differences in the billing weighting factors.

VECC was of the view that the default sheet should do more. It should also clearly explain the distinction between fixtures, connections and customers and how the relationship between the three is assumed for purposes of setting the default values. This sheet should also outline the billing approach that is assumed for purposes of the default values. Then a distributor should be required to confirm that its circumstances are similar to those implicit in the default values. If the circumstances are not the same, VECC suggested the distributor should be required to develop its own weighting factors. In the alternative, the CA Model could include different default values which reflect different circumstances.

While Rogers Cable supported Elenchus` recommendation to clarify the existing default factors in the CA Model, it was concerned that distributors will not be required to justify their choice of the default factors. Revenue-to-cost ratios will change with the selection of a weighting factor, and clearly the relative impact of weighting factors that are fixed relative to consumption will be more important to a class like USL where the load per connection is small. Consequently, Rogers Cable submitted that the choice of weighting factor, default or otherwise, should in all cases be subject to appropriate scrutiny when a distributor's cost allocation study is before the Board.

SEC was of the view that as with microFIT, Elenchus` recommendation that distributors be invited to insert their own weighting values in the CA Model had the potential to create significant consulting and other costs, and the value of doing so was not apparent. Elenchus did not review whether the cost was justified by the potential benefit.

Street Lighting class

CHEC was concerned that the Elenchus` report did not address known issues with street lighting that have arisen in the preparation of cost allocation studies over the past three to four years. Specifically, it referred to the need for consistent treatment of allocating cost to street lighting by distributors across the province. In the case of Kitchener-Wilmot Hydro's 2010 cost of service rate application (EB-2009-0267) and Kingston Hydro's 2011 cost of service rate application, relay/service entrance switches, or daisy chains, have been used as the connection points. That has significantly reduced the number of connections for these two distributors and improved the street lighting revenue-to-cost ratio. In the evidence from Kitchener-Wilmot Hydro's 2010 rate application, using relay/service entrance switches as the connection points for the street lighting class moved the revenue-to-cost ratio from 26.2% to 127.3%. The Board approved Kitchener-Wilmot Hydro's approach. As a result, the 2010 street lighting rates for Kitchener-Wilmot Hydro were reduced when the revenue-to-cost ratio was adjusted downward to be within the Board's range. AMO and several municipalities also highlighted these decisions.

In CHEC's view, the steps taken by Kitchener-Wilmot Hydro and Kingston Hydro to improve the street lighting ratio is an acceptable practise.

The Association of Municipalities of Ontario ("AMO") did not take issue with the Board's targeted revenue-to-cost ratios of 0.7 to 1.2 for the street light class, as long as the method used to determine these ratios fairly represents the actual costs to service street lights. AMO stated that, as a result of the post 2007 CA Model, most municipalities were hit with high rate increases for street lights between 2007 and 2009. AMO was concerned about the objective in the current review stating that there "are potential for refinements" because distributors have already adjusted their revenue-to-cost ratios to fall within the current target ranges. AMO believed that unless the existing problems are corrected, any further adjustments to the revenue-to-cost ratios will undermine the Board's objectives and unfairly punish AMO's municipal members.

As a result, AMO had three requests related to the manner in which costs to service street lights are determined. First, the Board should clearly and strongly state that distributors are to use the daisy chain approach to determining the number of street light connections from this point onwards. All future rate applications should reflect this method as it more fairly reflects the actual costs to service street lights and avoids the street light class subsidizing other rate classes. All distributors should also be required to provide an explanation on how they have determined the number of street light connections as part of their rate application just as Kitchener-Wilmot Hydro has done. Second, the Board should define connections more clearly in its existing documentation and communicate this clarification to distributors and other stakeholders. Third, the Board should place a moratorium on any further movement in revenue-to-cost ratios until the first two requests have been evenly and consistently implemented across all distributors in the province. Similar recommendations were advanced by CHEC, the Town of Oakville, Oakville Hydro and NBH.

SEC observed that Street Lighting is often owned or operated by the local municipality, who in many cases will be an owner of the distributor. According to SEC, one of the advantages of using default values that are not changed by the distributor is that the potential for the distributor to consciously or unconsciously favour the interests of the shareholder is removed. If distributors regularly change the weighting factors, it would be expected that this would become an issue engaging time and resources in cost of service applications. Unless there is some evidence that locally-developed weighting factors would be materially better – and Elenchus` report gives no indication of such evidence – it would seem to SEC to be a change that cannot justified.

2.5.4 THE BOARD'S APPROACH

USL as a separate class

The Board agrees with Elenchus and most stakeholders that the costs and load characteristics of customers in the USL classes are sufficiently different from those of other customers to justify being treated as separate classes in most cases. The Board therefore expects each distributor to include as part of their cost of service application a separate USL rate class in their CA Model and on their proposed Tariff of Rates and Charges.

A distributor that does not believe that it is necessary to create a separate USL rate class would have to demonstrate to the Board the benefits of not creating such a class. For example, the creation of a separate class may not be warranted in certain instances where a distributor has very few USL customers, or that their combined load is minimal. A distributor requesting an exemption for a separate USL class may also wish to consider requesting an exemption to demonstrate that the revenue-to-cost ratio of their USL customers does fall within the Board's target range.

The Board notes VECC's proposal for the treatment of meter related credit in situations where there is no separate USL rate class. In the Board's view, there is no need to apply VECC's proposed refinement to these cases.

Weighting factors for USL and Street Lighting classes

The Board agrees with the recommendation expressed by a number of stakeholders that some aspects of the terminology surrounding the USL class (for example, the definition of a customer, an account, a device) and the associated modeling methodology require clarification. The Board also agrees that clarification of the issues raised by various stakeholders related to the terminology and methodology used to allocate costs to the Street Lighting class is necessary. The need for clarification is demonstrated by the significant impact of a change in methodology that was observed in the Kitchener-Wilmot Hydro case discussed above. The Board believes that these issues are best addressed in the context of a separate consultation process focussed on the terminology and modeling methodology for the Street Lighting and USL classes.

Once that consultation process is completed, the underlying methodology and principles for allocating costs to the Street Lighting and USL classes will be identified and embedded in a separate worksheet in the CA Model. This worksheet will provide examples for how to derive weighting factors and will contain illustrative weighting factors.

The Board expects each distributor to assess the circumstances specific to its service area and ensure that the weighting factors they use appropriately reflect them. For example, if a distributor proposes to use a weighting factor included in the CA Model, the distributor should be able to show that the value is appropriate given its specific circumstances. Otherwise, it should propose customized weighting factor.

The Board notes that the current CA Model is already sufficiently flexible to allow distributor-specific circumstances to be taken into account. As mentioned above, a distributor should use weighting factors appropriate to its specific circumstances, and should make use of the CA Model's flexibility as required. The Board expects that the separate consultation process it plans to undertake will provide further guidance on how this flexibility can be used.

2.6 WEIGHTING FACTORS FOR SERVICE AND BILLING COSTS

2.6.1 DESCRIPTION OF ISSUE

Weighting factors are used in the CA Model to allocate certain costs to customer classes to better reflect cost causality. Where a distributor does not apply the weighting factors consistently or appropriately in its cost allocation studies, costs are not properly allocated to customer classes.

2.6.2 RECOMMENDATION OF ELENCHUS

Elenchus recommended that a separate input sheet be developed in the CA Model that would include default weighting factors for services and billing. Documentation should also be provided that explains the rationale for the different weighting factors.

Distributors should have the option of using their own values instead of the default values, if appropriate. Elenchus did not recommend updating the default values as distributors would have the option of using their own values if the default values are not appropriate.

2.6.3 STAKEHOLDER COMMENTS

The stakeholders were generally supportive of the recommendation, although participants differed on the extent to which default values should be relied upon. In addition, some stakeholders commented on specific implemented considerations.

There was widespread support for allowing distributors to substitute their own weighting factor values provided they could support their proposed factors analytically. Some stakeholders were of the view that default values should only be used where the distributor did not have the necessary information to determine an appropriate distributor-specific value. However, others recommended that the default values should be used unless the distributor could support a significantly different weighting factor.

LPMA and AMPCO, for example, suggested that the Board should require cost-based justification for any departure from default values and more exceptional departures should require more detailed justification. AMPCO also suggested that any departure from default weights should not be allowed simply on the basis of local policy preference. Furthermore, where a distributor requests an unusual departure from the default weight, it should also outline the cause of the departure and how it plans to bring any exceptional costs under control in the future.

Stronger support for the default values was provided by SEC in arguing that default values will be fine, for most or perhaps all distributors, and the additional cost to develop local default values would not be justified. In the interests of keeping costs down, SEC recommended that the Board update default values so they are as good as possible, and encourage all distributors to adopt them. In extreme case where distributors believe the default values are materially wrong for their customers, SEC suggests that distributors always have the right to make their case for a different approach.

Specific issues

VECC mentioned that during the Stakeholder meeting questions were raised regarding the treatment of customers (e.g., school boards) that have many connections which are separately metered but who are sent only one “aggregated bill”. Such arrangements could have an impact on the weighting factors used for billing and could be considered if/when distributors develop their own values. However, the development of alternative factors would need to consider not only the reduced costs due to having to issue only one bill for a number of connections but also any increased costs with preparing a single aggregated bill.

VECC noted that the introduction of such weighting factors gives rise to the question as to whether such differences should be reflected in the rate design for the affected classes so that costs that are allocated to a class are properly attributed to individual customers in that class. This would be similar to the credit provided to USL customers and the transformer ownership allowance (“TOA”).

2.6.4 The Board’s Approach

The Board is of the view that default weighting factors should be utilized only in exceptional circumstances. In general, distributors have had sufficient time since preparing their 2006 Cost Allocation Information Filings to have gained the experience necessary to enable them to propose appropriate distributor-specific weighting factors.

To facilitate the introduction of such factors into the CA Model, a separate worksheet will be added to the CA Model that can be used to derive distributor-specific weighting factors. This worksheet will include weighting factors for unmetered loads in keeping with the approach set out in the previous section of this Report.

As recommended by Elenchus and supported by most stakeholders, this new worksheet will be accompanied by documentation describing the standard methodology for deriving the weighting factors in order to provide further guidance to distributors . As mentioned in section 2.5.4, additional guidance is expected to be provided on terminology and methodology for the Street Lighting and USL rate classes after the completion of a separate consultation process that the Board plans to initiate in the near term.

Default values and the basis on which they were derived will be included in the documentation; however, any distributor that proposes to use those default values will be required to demonstrate that they are appropriate given their specific circumstances.

2.7 TREATMENT OF TRANSFORMER OWNERSHIP ALLOWANCE

2.7.1 DESCRIPTION OF ISSUE

The transformer ownership allowance (TOA) compensates customers for providing their own transformation facilities instead of having the distributor provide transformation facilities for them. The distribution rates charged by distributors to customers include the cost of providing transformation facilities and the TOA reflects the savings to the distributor of not having to provide transformation assets.

The default in the current CA Model is not consistent with the Board's updated Filing Requirements for Transmission and Distribution Applications (the "Filing Requirements"). With the update in the Filing Requirements, it may be possible to streamline the CA Model.

2.7.2 RECOMMENDATION OF ELENCHUS

Elenchus recommended that the CA Model be modified to ensure that only customer classes that include customers that provide their own transformation facilities are included in the determination of the TOA. Furthermore, the updated TOA treatment now set out in the Filing Requirements, including the requirement that the credit be calculated on a $/kW basis, should be reflected as clearly as possible within the CA Model.

2.7.3 STAKEHOLDER COMMENTS

Most stakeholders supported the recommendation, pointing out that the revision is essentially an administrative matter that ensures that the CA Model does not contain any complicating artefacts of the approach that was originally embedded in the CA Model.

VECC and CHEC noted the Filing Requirements issued in 2010 already accomplish the objective of Elenchus` recommendation as the "cost" of the TOA is excluded from the revenue requirement to be allocated and distribution revenues by class used in the CA Model are net of the TOA. The "costs" of the TOA are then included in the rate design for affected customer classes.

SEC and VECC also emphasized that the cost of the TOA should be charged only to other customers in the same class and there should be no impact on other customer classes.

LPMA suggested that simpler instructions, including a numerical example, would allow distributors and other intervenors to better understand and apply this aspect of the CA Model.

AMPCO was of the view that Elenchus` recommendation is a step in the right direction but that additional guidance should be provided. AMPCO suggested that distributors should be required to track costs of the transformation specific to these classes (typically GS 50 KW and above). AMPCO provided another alternative, which it considers to be the simplest way to resolve the issue, and that is to remove transformation services from the cost allocation process.

Oakville Hydro stated that Option 3 in Elenchus` report calls for establishing customer classes that include the requirement that the customer provides their own transformation facilities. These customer classes would include all customers that own their transformation assets and therefore there would be no need to determine the TOA. Oakville Hydro suggested that Elenchus` recommendation should be combined with Option 3. Distributors would then be permitted to include classes that have some customers that provide their own transformer assets in the calculation of the TOA, and exclude classes for which all customers provide their own transformer assets.

2.7.4 THE BOARD'S APPROACH

The Board agrees with VECC and CHEC that the workaround to the default TOA treatment in the CA Model, as set out in Chapter 2 of the Filing Requirements for Transmission and Distribution Applications issued by the Board in June 2010 (the "Filing Requirements"), achieves the objective reflected in the Elenchus recommendation, with the distribution revenues by class being net of the TOA. The Board finds that this treatment of the TOA is appropriate and that the CA Model should be streamlined to reflect it so that a workaround is no longer required. Supporting documentation will be provided to ensure that the methodology, as updated to accord with the Filing Requirements, is clear and easy to follow in the CA Model.

2.8 ALLOCATION OF HOST DISTRIBUTOR COSTS TO EMBEDDED DISTRIBUTORS

2.8.1 DESCRIPTION OF ISSUE

There are many instances of host/embedded distributor relationships in Ontario. This situation arises where one distributor (the host) uses its facilities to carry electricity to another distributor (the embedded) that is located in or adjacent to the host distributor's service area. The charges levied by a host distributor on its embedded distributor are ultimately recovered from the embedded distributor's customers.

In many instances, host distributors do not group embedded distributors in a separate customer class. Instead, the embedded distributors are included in the host distributor's General Service customer class. The customer classification assigned to the embedded distributor affects the costs that are allocated to the embedded distributor and ultimately paid by its customers.

2.8.2 RECOMMENDATION OF ELENCHUS

Elenchus recommended that Schedule 10.7 of the 2006 EDR Handbook should continue to be used to identify the assets used by host distributors in supplying their embedded distributors, and that this should be incorporated into the CA Model.

Elenchus also recommended that the Board establish a threshold above which host distributors would have to establish a separate rate class for their embedded distributor(s). Under Elenchus' recommended thresholds, separate charges would be applicable if the embedded distributor represents more than 10% of the host distributor's total volume of sales, or if the embedded distributor accounts for more than 500 kW in average demand per month.

2.8.3 STAKEHOLDER COMMENTS

Elenchus' recommendation to use Schedule 10.7 of the 2006 EDR Handbook was supported by all stakeholders with the caveat that it should be updated to reflect subsequent refinements that have been accepted by the Board. However, many stakeholders questioned the proposed threshold for requiring distributors to establish a separate class for embedded distributors.

Use of Schedule 10.7 of the 2006 EDR Handbook

VECC was concerned that Schedule 10.7 from the 2006 EDR Handbook was developed prior to the development of the Board's CA Model. As a result, there are inconsistencies between the two in terms of both the cost elements allocated to embedded distributors and the allocation methodologies used for the individual cost elements. If distributors are to directly assign costs to their embedded distributor(s) then, VECC submitted, the approach as set out in Schedule 10.7 needs to be updated. VECC suggested that such an update could be accomplished by either Board staff preparing a proposal that could be commented on by interested parties, or the Board could establish a small working group of interested parties to develop detailed recommendations as to how the schedule could be revised in the near term.

CHEC also noted that Schedule 10.7 of the 2006 EDR Handbook was revised and enhanced in EB-2007-0900, the Cambridge and North Dumfries Hydro 2008 IRM Rate Application. This revision takes into consideration costs that were not in the original Schedule 10.7. CHEC suggested that a revised Schedule 10.7 could be used for allocation of host distributor costs to embedded distributors.

Threshold for a separate embedded customer class

The views of stakeholders were split with respect to Elenchus' recommended threshold.

VECC noted that Elenchus' recommendations appeared to assume that embedded distributors are generally served only by "bulk facilities" instead of primary and/or secondary assets and that, since most distributors' models do not separate out "bulk assets", the models themselves are not sufficiently refined to determine the appropriate costs. VECC believed this may not be the case and that the types of assets used to serve the embedded distributors may be no different from those used to service other similar sized customers. As a result, VECC submitted that before adopting Elenchus' approach, the distributors should be required to explain what is unique about the embedded utility customer relative to other similar sized customers. If a satisfactory explanation can be provided, then the distributor should be permitted to adopt Elenchus' recommended approach and the relevant costs would be determined through a separate process. Otherwise, the embedded distributor should simply be treated as a separate customer class within the standard model (i.e., no direct cost assignment).

VECC also stated that the purpose of Schedule 10.7 is to determine the cost of serving embedded distributors for purposes of designing an appropriate rate for these customers. If embedded distributors are included in the appropriate GS class(es), there is no need for Schedule 10.7 for the purposes of cost allocation. If they are to be considered a separate rate class, in VECC's view, then either:

a) They should be included in the CA Model as such and the relevant allocation factors should be applied to determine the costs that need to be recovered from them, or
b) They should be included in the CA Model and the relevant costs should be determined through a separate process (i.e., direct allocation).

LPMA and SEC were concerned that the creation of an artificial threshold for delivery points is not appropriate. LPMA suggested that the Board should move cost allocation for embedded distributors, regardless of size, to a methodology more in line with the historical practices in the natural gas industry. LPMA recommended that a separate rate class should be established for embedded distributors currently served in the GS 50 kW to 4,999 kW rate class. This is an existing break point for GS customers. SEC's concern was based on the view that it would be unusual for the Board to establish conditions, rates, or thresholds without some evidentiary basis, and in SEC's view the unsupported judgment of a consultant is not an appropriate basis.

In contrast, distributors generally agreed that the Board should adopt the thresholds recommended by Elenchus, above which host distributors would be required to run the analysis to determine whether or not separate charges for embedded distributors should be set. NBH, however, added the caveat that once a distributor exceeds the recommended threshold, there should be a review of the embedded distributor to determine whether there are unique characteristics, along with a material difference in costs that would justify a separate rate class. The recommendation that host distributors be required to set separate charges, with the only stipulation being a threshold test, does not take into account that in some instances an embedded distributor has commonality with the class that it is in. Immaterial cost differences may not justify setting up a new rate class. NBH also commented that the Board should provide clear instructions that would guide a utility in determining the costs of an embedded distributor.

Hydro One noted that the wording of Elenchus' recommendation needs to be revised slightly since it does not necessarily require the establishment of a separate charge applicable only to embedded distributors.

AMPCO was of the view that the threshold test for establishing separate charges for embedded distributors seemed reasonable and appropriate, but recommended that the effect of the recommended 500 kW threshold should be determined before implementation.

LPMA and AMPCO stated that, in the stakeholder session, questions were raised related to costs that perhaps should not be allocated to embedded distributors (CDM, bad debt, etc.) and that Elenchus had not researched this issue. LPMA and AMPCO recommended that the Board should review the CA Model to ensure that all allocated costs are appropriate to embedded distributors.

AMPCO also suggested that since Hydro One is the dominant host distributor in Ontario and has a specific Sub-Transmission ("ST") class with similar threshold criteria as those recommended by Elenchus, the Board should consider allowing Hydro One to continue classifying embedded distributors as ST-class, perhaps with modifiers to avoid what is referred to as rate pancaking.

LPMA noted that Elenchus did not do any research on the number of embedded distributors that would qualify for a separate rate class if the Board accepted its recommended thresholds or how many would not qualify for the separate rate class. LPMA believed the Board should undertake to obtain information on the number and the associated load of the embedded distributor delivery points, and feels this information would be useful in determining the validity of Elenchus' proposed thresholds.

LPMA also suggested that the design of rates, which is outside of this process, may be different based on the size of the customer, as it is in the natural gas industry. LPMA stated that the key issue is the allocation of costs to embedded customers should be based on cost causality. Categories of costs that are not incurred to serve these customers should not be recovered from these customers.

2.8.4 THE BOARD'S APPROACH

Use of the Schedule 10.7 of the 2006 EDR Handbook Methodology

The Board is of the view that the methodology outlined in Schedule 10.7 of the 2006 EDR Handbook, as updated in proceeding EB-2007-0900 referred to above, provides an appropriate basis for estimating the costs to be allocated to an embedded distributor customer class. That methodology considers the portion of the host distributor's Low Voltage ("LV") facilities that are used to serve the embedded distributor, as well as the proportion of the load on those facilities that is bound for the embedded distributor's service area.

Threshold for a separate embedded customer class

The Board is of the view that it is generally appropriate for any distributor with total embedded distributor load that exceeds (a) defined threshold(s) to treat its embedded distributor(s) as a separate customer class.

The Board accepts the view of several stakeholders that more analysis regarding the appropriate threshold(s) is required prior to adopting (a) specific percentage of load or aggregate demand threshold(s). The Board believes that this further analysis will require the collection of additional data on embedded loads from distributors. The Board will issue a letter shortly to all rate-regulated electricity distributors providing further details on this information request. Upon review and analysis of this information, the Board will determine what the threshold(s) should be. The Board expects that any threshold it will determine will be considered in cost of service applications starting with the 2013 rate year.

Once the Board has determined the threshold(s), any distributor that does not establish a separate class for its embedded distributor(s) even though the characteristics of the embedded distributor(s) exceed the threshold(s) will be expected to provide justification for not creating a separate class. The justification should include a description of the customer class to which embedded distributors are assigned (for example, an existing General Service class defined by demand over 1000 kW), and an analysis showing that the revenues collected from the embedded distributor(s) are sufficiently similar to the costs of serving the embedded distributor(s).

2.9 CHANGES TO REVENUE TO COST RATIO RANGES

2.9.1 DESCRIPTION OF ISSUE

The Street Lighting, Sentinel Lighting and General Service 50 kW to 4,999 kW customer classes have revenue-to-cost ratio ranges that are wider than the Board's ranges for other customer classes. Given that distributors have now gained experience with using the CA Model and have started to move these three customer classes closer to the Board's revenue-to-cost ratio ranges used for other customer classes, it is an appropriate time for a review of the revenue-to-cost ratio ranges for these three customer classes.

2.9.2 RECOMMENDATION OF ELENCHUS

The Elenchus Report recommended narrowing the revenue-to-cost ratio ranges for the three customer classes. The recommended revised range for the Street Lighting and Sentinel Lighting classes was 0.8 to 1.2, compared to the current Board-approved range of 0.7 to 1.2. Elenchus recommended that this change should be achieved over three to four years as distributors apply to the Board to have their rates rebased.

For the General Service 50 kW to 4,999 kW class, Elenchus recommended a revenue-to-cost ratio range of 0.8 to 1.4 compared to the current Board-approved range of 0.8 to 1.8.

2.9.3 Stakeholder Comments

Stakeholder comments were generally supportive of narrowing these three widest target ranges, although several did not consider a phase-in to be necessary and several expressed concern about the asymmetry of the proposed range for GS 50 kW to 4,999 kW class and the timing of the transition for the Street Lighting class.

Three ratepayer representatives commented that the pace of any revenue-to-cost ratio adjustment should only be limited by concerns about the rate or bill impacts, in which case a mitigation plan, such as a phasing-in, should be proposed. One of these ratepayer representatives specified that, unless the adjustment would lead to a total bill increase over 10% for any rate class, the adjustment should be performed in one step.

GS 50 kW to 4,999kW rate class

While no stakeholder objected to the narrowing of the target range for the GS 50 to 4,999 kW rate class, stakeholders expressed different views as to what the narrower target range should be. Comments received from most municipal and utility representatives supported the range proposed by Elenchus of 0.8 to 1.4. In contrast, four ratepayer representatives and Oakville Hydro argued for a range of 0.8 to 1.2. There was concern that the need for the asymmetric range proposed by Elenchus was not supported by statistical analysis. In particular, AMPCO argued that standardization in the calculation of the TOA has removed a major source of variation and that “the statistical spread that may have justified a broad range should no longer apply.” AMPCO was also of the view that, given it estimated that the GS 50 to 4,999 kW rate class accounts for 10% or less of total distribution revenues, phasing-in any adjustments over 3 to 4 years to the proposed upper end of the range of 1.2 is not likely to have a significant impact on other customer classes.

LPMA suggested lowering the upper end of the range to 1.2 in two steps: for each utility’s next cost of service the target range should be 0.8 to 1.4 and for their subsequent cost of service it should be brought down to 0.8 to 1.2.

Street Lighting and Sentinel Lighting rate classes

Two municipality representatives and CHEC recommended that the target ranges for street lighting and sentinel lighting be maintained at 0.7 to 1.2 until the impact of modelling refinements are known. Furthermore, CHEC suggested that distributors under incentive regulation that are still phasing-in the implementation of revenue-to-cost ratio adjustments of their street lighting rate class be allowed to apply, as part of their annual incentive regulation application, for a stay of such implementation. In CHEC's submission, such applications would have to be supported by evidence that the street lighting ratio already falls within the Board approved-range based on revised cost calculations that take into account the recent Kitchener-Wilmot Hydro and Kingston Hydro decisions.

Hydro One, on the other hand, considered the Elenchus proposal to gradually increase the bottom of the range from 0.7 to 0.8 for the street lighting and sentinel lighting rate classes over a period of 3 to 4 years to be appropriate. CLD also supported this approach for the street lighting rate class.

CLD submitted that adjusting the target range for the sentinel lighting rate class was unwarranted given that it is a legacy rate class.

Additional comments

SEC submitted that, in addition to establishing common ranges for all rate classes, the Board's goal should be to move towards a narrower range within a reasonable period of time, "with a goal of getting to the 0.95 to 1.05 revenue-to-cost ratio range that is common across Canada." In contrast, while VECC recognized that well established cost allocation models that are supported by long-standing statistically valid load research programs typically use revenue-to-cost ratio ranges of 0.9 to 1.1 or 0.95 to 1.05, it was of the view that given the limited load research data supporting the cost allocation models for most Ontario distributors and the acknowledged the need for improved cost data. VECC believes the ranges should be 0.8 to 1.2 or 0.85 to 1.15 at best.

VECC noted that the some distributors have been approved in recent cost of service applications to adjust their revenue to cost ratios closer to 1.0 even though they were already within the Board's target range. VECC also noted that other distributors have only sought to reach the end of the target ranges without any further adjustments. VECC recommended that "a more standard/principled" approach to this issue is required.

2.9.4 THE BOARD'S APPROACH

As noted in its September 2, 2010 letter, the Board considered that it was appropriate to consider narrowing the three widest target ranges, based on the Board's experience to date with cost allocation and the fact that most distributors have now adjusted or are phasing-in an adjustment to their revenue-to-cost ratios to fall within or at the end of the existing revenue-to-cost ratio target ranges. The Board notes the general agreement among stakeholders that these three widest ranges can be narrowed at this time.

The Board agrees with the comments of stakeholders that the pace at which revenue-to-cost ratios should be adjusted to a Board-approved ratio should only be affected by concerns regarding the impact on any rate classes. The Board notes that it has a consultation process underway as part of the RRF that will review, among other things, circumstances where the need for rate mitigation may arise as well as rate mitigation options (EB-2010-0378). To the extent that the application of the Board's cost allocation policies results in a significant shift in the rate burden amongst classes relative to the status quo, distributors should be prepared to address potential mitigation measures. As in the past, and until a review of alternative options is completed as part of the Board's rate mitigation consultation, the general approach to mitigating rate impacts should be to bring the affected class into the allowed range over multiple years; in other words, going beyond the cost of service year and completing the transition during the subsequent Incentive Regulation Mechanism ("IRM") period.

GS 50 kW to 4,999 kW rate class

With regard to the GS 50 kW to 4,999 kW class, the Board agrees with that there is no evidence at this time to suggest that the revenue-to-cost ratio should remain asymmetric. The Board finds that a target range of 0.8 to 1.2 for the GS 50 kW to 4,999 kW class is appropriate at this time. As noted above, the pace at which the top of the range for this class is moved to 1.2 should only be affected by concerns regarding the impact on any other rate classes.

Street Lighting and Sentinel Lighting rate classes

As discussed above in section 2.5.4, a separate consultation will be initiated involving the Street Lighting class. As such, the revenue-to-cost ratio for the Street Lighting class will remain at 0.7 to 1.2 pending the outcome of that consultation.

With respect to the Sentinel Lighting class, the Board is not convinced that any adjustments to its target range would be unwarranted by reason of the class being considered a legacy rate class, assuming that to be the case. In the Board's view, cost causality is an overarching principle that should be applied regardless of whether a rate class can be considered legacy or not. In addition, there is no indication that the Sentinel Lighting rate class will be phased out by all distributors imminently. The Board has concluded that the revenue-to-cost ratio for this rate class should be narrowed to 0.8 to 1.2.

For ease of reference, the Board's revenue-to-cost ratio ranges to be implemented through cost of service applications starting with the 2012 rate year are outlined in Table 1 below. Except for the ranges for the GS 50 to 4,999 kW and Sentinel Lighting classes, all other ranges remain unchanged from the 2007 Report.

Table 1: Revenue-to-cost Ratio Ranges

SERVICE CLASS	RANGE
Residential	85 to 115%
General Service < 50 kW	80 to 120%
General Service 50 to 4,999 kW	80 to 120%
Large User	85 to 115%
Unmetered Scattered Load	80 to 120%
Street Lighting	70 to 120%
Sentinel Lighting	80 to 120%

As indicated in its September 2, 2010 letter, the Board expects that with the installation of smart meters and the availability of sufficient smart meter data, better cost allocators for the CA Model will become available and a more comprehensive review of the Board's cost allocation policies will become feasible. The Board anticipates that such a comprehensive review may provide an opportunity to further refine its target ranges. In the meantime, the Board's policy remains that distributors should endeavour to move their revenue-to-cost ratios closer to one if this is supported by improved cost allocations.

2.10 Changes Related to the Transition to IFRS

2.10.1 Description of Issue

There are a number of accounts that have been identified which have not been previously included in the CA Model. In addition, publicly accountable enterprises are to transition to IFRS by 2012, which could have implications for the CA Model.

2.10.2 Recommendation of Elenchus

Elenchus recommended adding a set of identified accounts to the CA Model that are not used in the CA Model, for the purpose of making the fact that these accounts are not allocated to customer classes more explicit and transparent.

With respect to IFRS, Elenchus suggested that unless there are changes to the existing accounts of the Uniform System of Accounts ("USoA") that affect the way in which the costs should be allocated, or new USoA accounts are created, IFRS would have no impact on the CA Model. To date, no such changes have been identified.

2.10.3 Stakeholder Comments

Inclusion of Additional Accounts for Completeness

Most stakeholders were silent on the issue of adding to the CA Model, for the sake of completeness, the list of USoA accounts not required for cost allocation purposes. VECC had no objection to inclusion of the additional accounts if it makes it easier for distributors to use the CA Model, even though the accounts have no impact on the distributor's revenue requirement. CLD was of the view that adding the set of accounts recommended by Elenchus may cause unneeded confusion, as the accounts would be added only for information purposes and would not be allocated because they are not related to distribution revenue. LPMA was also of the view that the accounts identified should not be included in the CA Model, as these accounts do not impact the revenue requirement of distributors.

Transition to IFRS

No stakeholder identified specific changes to the CA Model due to the transition to IFRS. Most stakeholders agreed with Elenchus' views that IFRS alone should not necessitate changes to the CA Model, unless it triggers need for the Board to make changes (e.g., definition) to the USoA accounts currently used.

It is recognized however, that the transition to IFRS is likely to result in an increase in the total number of USoA accounts since some categories of accounts will require more detail. CHEC suggested that if new accounts are added to the CA Model, the Board may want to include some dummy accounts in the current CA Model for future use.

LPMA suggested that until IFRS rules are known with certainty, any changes to the CA Model would be based on speculation, and could end up being counterproductive.

SEC was concerned that Elenchus did not look at whether IFRS would cause the CA Model to produce materially different results. Elenchus looked at whether the CA Model was no longer correct, but not whether new inputs would produce less reasonable results.

SEC stated that given some distributors have reported significant potential impacts of IFRS for particular cost categories, it would appear appropriate to model those changes within the CA Model to see if there are material changes in results and, if so, whether those changes are justified.

As an example, SEC mentioned the significant impact expected with regard to capitalization rules. To the extent that costs, when capitalized, are allocated differently than OM&A costs, this may represent a shift in cost responsibility. SEC suggested that it is appropriate for the Board to determine through research whether any such shifts are material and/or appropriate.

CLD stated that many costs currently recorded by most distributors within capitalized overheads may be disallowed for capitalization purposes under IFRS. Currently, the Accounting Procedures Handbook ("APH") is silent or not prescriptive on the treatment of these costs (e.g., engineering supervision, employee training and other indirect employee benefits, as well as procurement costs related to inventory and stores items). CLD suggested that now may be an appropriate time for the Board to provide direction to distributors on the accounting treatment of these costs to ensure consistent treatment by distributors. In light of this, CLD believes Elenchus should provide recommendations on the appropriate treatment in the CA Model.

Oakville Hydro observed that the Board initiated a work group to develop recommendations on how IFRS should be adopted in an IRM environment. Oakville Hydro suggested that the Board consider whether the work group could also identify the impact of IFRS on the balances in the USoA accounts so that stakeholders can assess their impact on cost allocators.

2.10.4 THE BOARD'S APPROACH

The Board concurs with the view of Elenchus and stakeholders that no changes to the structure of the CA Model are anticipated as a result of the transition to IFRS. Nevertheless, as a result of the transition to IFRS, it may be necessary to expand the CA Model to accommodate the adoption of additional USoA accounts. As part of the implementation process for the approach set out in this Report, the ability of the CA Model to accommodate an increased number of accounts should be ensured. The inclusion of dummy accounts may be a convenient way to accomplish this.

Once changes to the USoA to implement IFRS have been finalized, it will be appropriate to consider whether any refinements in the allocators used for any resulting new or broken down accounts are necessary or desirable. It would be premature to attempt to implement IFRS-related changes to the CA Model until that time.

3 NEXT STEPS

As noted in Chapter 1, a CA Working Group will be established to work with Board staff to identify the need for and recommend necessary revisions to the CA Model, and to provide input on the development of supporting documentation.

Specifically, the implementation issues to be addressed by the CA Working Group will include, but may not be limited to:

- Development of a separate worksheet in the CA Model for the calculation of microFIT administrative costs;
- Development of a separate worksheet in the CA Model for allocating the major components of miscellaneous revenues to customer classes in a manner that matches the allocation of the corresponding costs;
- Revisions to the CA Model that allocate the remaining miscellaneous revenues on the basis of composite OM&A;
- Development of a separate worksheet in the CA Model for deriving all weighting factors on a distributor-specific basis, including appropriate weighting factors for allocating costs to unmetered loads:
    - This separate worksheet is intended to make the CA Model more user-friendly and to emphasize the “customizable” aspect of the weighting factors. The CA Working Group will focus on the technical recommendations for the proposed CA Model worksheet.
    - As mentioned earlier in this Report, the provision of further guidance on the terminology and modelling methodology for the Street Lighting and USL classes will be provided through a separate consultation process.
- Streamlining of the existing CA Model worksheets to clarify the proper treatment of the Transformer Ownership Allowance in accordance with Chapter 2 of the Filing Requirements;
- Expansion of the CA Model, if necessary, to ensure that additional USoA accounts can be conveniently and consistently accommodated once changes to the USoA due to the transition to IFRS have been finalized; and
- Provision of input on the development of supporting documentation to clarify the proper use of the CA Model by distributors with respect to each of the above issues.

Once the work of the CA Working Group has been completed, the Board will issue a revised CA Model.

As noted in section 2.5.4, the Board will initiate a separate consultation process on the terminology and modeling methodology for the Street Lighting and Unmetered Scattered Load classes. Further details on this consultation will be communicated in the near future.

This Report also indicates that another separate consultation will be undertaken in the near term to further examine issues associated with load displacement generation (see section 2.3.4). Further information on this consultation will also be communicated in the near term.

Finally, the Board noted in section 2.8.4 the need for more analysis on proposed threshold(s) above which a host distributor would be expected to create a separate customer class for its embedded distributor(s). This further analysis will require the collection of data from embedded and host distributors. Details of the data request will be communicated to distributors in the near future.

Appendix A: List of Stakeholders

The October 15, 2010 Elenchus Report, entitled *Cost Allocation Policy Review: Options and Preferred Alternatives*, is available on the Board's web site at:

http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0219/Cost%20Allocation%20Policy%20Review%20Report%20Oct%2015.pdf

Below is the list of stakeholders that provided written comments on the Elenchus Report.

- Association of Major Power Consumers in Ontario ("AMPCO")
- Association of Municipalities of Ontario ("AMO")
- Cornerstone Hydro Electric Concepts Association Inc. ("CHEC")
- City of Welland
- City of Windsor
- Coalition of Large Distributors ("CLD")
- Electricity Distributors Association ("EDA")
- EnWin Utilities Ltd. ("EnWin")
- Hydro One Networks Inc. ("Hydro One")
- London Property Management Association ("LPMA")
- North Bay Hydro Distribution Ltd. ("NBH")
- Oakville Hydro Electricity Distribution Inc. ("Oakville Hydro")
- Power Workers' Union ("PWU")
- Rogers Cable Communications Inc. ("Rogers Cable")
- School Energy Coalition ("SEC")
- Town of Oakville
- Vulnerable Energy Consumers Coalition ("VECC")

Appendix I

Chapter 3 – Filing Requirements for Electricity Transmission and Distribution Applications – revised June 28, 2012

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Ontario Energy Board   Commission de l'énergie de l'Ontario

Ontario Energy Board

Chapter 3 of the Filing Requirements For Electricity Transmission and Distribution Applications

June 28, 2012

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Chapter 3 Filing Requirements for Incentive Regulation Mechanism Rate Applications

1.0 Introduction

The Ontario Energy Board establishes the rates of electricity distributors using a combination of annual incentive regulation mechanism ("IRM") adjustments and periodic cost of service reviews.

The Filing Requirements herein replace version 3.0 of Chapter 3 of the *Filing Requirements for Transmission and Distribution Applications* ("Filing Requirements"), dated June 22, 2011. The requirements set out the Board's expectations for filings by electricity distributors that are applying for annual rate adjustments under an IRM plan.

In its October 27, 2010 letter regarding the development of a Renewed Regulatory Framework for Electricity ("RRFE"), the Board announced that it was extending the 3rd Generation IRM ("IRM3") plan until such time as three RRFE policy initiatives have been substantially completed. As such, the four-year rate-setting cycle (i.e. rebasing plus three years of IRM) remains in place for the time being.

Version 3.0 of Chapter 3 of the Filing Requirements announced that the Board was no longer allowing distributors to file a 2nd Generation IRM application. The Board determined that the IRM3 plan would provide a uniform IRM framework to all distributors, including those that have not rebased since the 2006 EDR but elected to remain on an IRM plan. Hence, all IRM applications must be filed under IRM3.

1.1 Key References

The documents listed below are key to understanding these Filing Requirements:

- *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation Mechanism for Ontario's Electricity Distributors* (filing guidelines: Appendix F) – December 20, 2006;
- *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, December 11, 2009
- *Guidelines for Electricity Distributors' Conservation and Demand Management* (EB-2012-0003) – April 26, 2012;
- *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* – July 14, 2008;
- *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* – September 17, 2008;
- *Addendum to the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* – January 28, 2009;
- *Guideline (G-2008-0001) on Retail Transmission Service Rates* – October 22, 2008 (Revision 3.0 June 22, 2011 and any subsequent updates);
- *Guideline G-2011-0001:Smart Meter Funding and Cost Recovery – Final Disposition*, December 15, 2011;
- *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR)* – July 31, 2009;
- *Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence* (EB-2009-0397) - May 17, 2012;
- *Report of the Board on Transition to International Financial Reporting Standards* EB-2008-0408 – July 28, 2009; and
- *Addendum to Report of the Board EB-2008-0408 – Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment* – June 13, 2011 and the letter of the Board, dated April 30, 2012.

1.2 Grouping for Filings

Distributors that are seeking rate adjustments effective January 1, 2013 will be required to file their IRM application by August 3, 2012.

For those distributors that are seeking rate adjustments effective May 1, 2013, the Board will assign electricity distributors in one of six application groupings noted below based on the expected level of complexity of the application. The length of time required to review an application is commensurate upon its level of complexity. Applications of greater complexity and hence requiring more time to review will be required to be filed first. Staggering of the applications allows the Board and other stakeholders to appropriately schedule resources to allow for adequate review of the applications. The deadlines for filing an IRM application have been determined so that, in the normal course of events, a Decision and Order would be issued in time for a May 1 implementation date.

The application deadlines are as follows:

- Friday August 31, 2012
- Friday September 14, 2012
- Friday September 28, 2012
- Friday October 12, 2012
- Friday October 26, 2012
- Friday November 9, 2012

Board staff will survey potential IRM applicants in June 2012 requesting that applicants that are seeking rate adjustments effective May 1, 2013 identify the expected elements of their IRM application for the purpose of assisting the Board in assigning a filing deadline for each electricity distributor. Applicants expected to include one or more of the following elements in their application will be assigned an earlier filing date :

- LRAM to account for persistence of 2010 CDM programs in 2011 and 2012;
- LRAM Variance Account disposition;
- Rate Harmonization pursuant to a prior Board decision;
- Z Factor claim;
- Incremental Capital Module claim;
- Smart Meter Cost Recovery; and
- Renewable Generation and/or Smart Grid Rate Adder request.

The assignment of distributors under these filing dates will be identified in a separate communication.

1.3 Components of the Application Filing

Each application must include:

- A Manager's Summary thoroughly documenting and explaining all rate adjustments applied for;
- The contact information for the IRM application - The primary contact for the IRM application may be a person within the applicant's organization other than the primary licence contact. The Board will communicate with this person during the course of the application. After completion of the IRM application, the Board will revert communication to the primary licence contact;
- A completed Rate Generator[1] and supplementary work forms[2], provided by the Board, both in electronic (i.e. Excel) and PDF format;
- A PDF copy of the current Tariff Sheet;
- Supporting documentation cited within the application (e.g. excerpt of relevant past decisions and/or settlement agreements, relevant Reporting and Record-keeping Requirements ("RRR") data and Revenue Requirement Work Form ("RRWF"))[3];
- A statement as to which publication(s) the applicant's notice will be appearing, whether it is a paid publication or not and the readership and circulation numbers; and
- A text-searchable Adobe PDF format for all documents.

1.4 Bill Impacts

The Rate Generator includes a bill impact calculation by rate class and produces total bill impacts excluding any changes to the Regulated Price Plan ("RPP"). These calculations are similar to that used in assessing rate applications in recent years. The latest RPP at the time of publication of the Rate Generator model will be used and will remain unchanged for the duration of the application process.

[1] The Rate Generator is a Microsoft Excel workbook that calculates a distributor's proposed tariff of rates and charges in an IRM Application.
[2] Include the Shared Tax Savings Workform, Revenue Cost Ratio Adjustment Workform, Incremental Capital Module Workform, Deferral and Variance Account Workform and RTSR Adjustment Workform.
[3] The Revenue Requirement Work Form is filed as part of the draft rate order in the last rebasing application.

1.5 Applications and Electronic Models

The models issued by the Board are provided to assist the distributor in filing a rate application. An application to the Board is the distributor's responsibility and the Board expects that the application will be complete and accurate. While the Board may issue electronic filing models for use in IRM rate applications, the distributor bears the responsibility to ensure the accuracy and appropriateness of any models that it uses in supporting its application. The distributor is responsible for advising the Board of any concerns it may have regarding calculations flowing from the models. Utilization of the models issued by the Board does not necessarily constitute Board acceptance.

1.6 Other Rate Adjustments

The Rate Generator will be made available on the Board's web site. The model will include generic base rate adjustments, rate adders and rate riders common to most applicants. Where a distributor has continuing adjustments, and/or rate adders and/or rate riders from previous decisions that are not in the generic model (such as the phased implementation of a rate harmonization process) the distributor should contact Board staff for specific guidance.

2.0 Elements of the IRM Plan

2.1 Price Cap Index Adjustment

The Gross Domestic Product Implicit Price Index for Final Domestic Demand (GDP-IPI) as published by Statistics Canada will be used as the price escalator for IRM applications.

For rates effective January 1, 2013, the GDP-IPI will be the annual percentage change in the GDP-IPI for the period 2011 Q3 to 2012 Q2 to 2010 Q3 to 2011 Q2. For rates effective May 1, 2013, the GDP-IPI will be the annual percentage change for calendar year 2012.

The Rate Generator will originally include the preceding calendar year's GDP-IPI value as an estimate of the inflationary adjustment to input prices (i.e. costs) for the upcoming rate year. Statistics Canada typically publishes data approximately two months following a period. Upon publication by Statistics Canada, the Board will issue a letter establishing the updated GDP-IPI. Board staff will update the GDP-IPI in each distributor's Rate Generator in order to calculate the price cap index adjustment for final distribution rates for all applicants. Distributors will have an opportunity to comment on the accuracy of Board staff's update as part of the draft Rate Order process.

The price cap index adjustment is determined as the annual percentage change in the GDP-IPI less the X-Factor. The X-factor is 0.72% plus a stretch factor. The value of the stretch factor is specific to each distributor for each rate year, and will be one of the following values: 0.2%; 0.4%; or 0.6%. The Board will determine each distributor's stretch factor. The distributor specific stretch factors will not be available before the application is filed. Therefore, the Rate Generator will include a proxy stretch factor of 0.4%. Once the distributor specific stretch factors become available, Board staff will adjust the stretch factor in each distributor's individual Rate Generator. Distributors will have an opportunity to comment on the accuracy of Board staff's update as part of the draft Rate Order process.

The price cap index adjustment will not be applied to the following components of delivery rates:

- Rate Adders;
- Rate Riders;
- Low Voltage Service Charges;
- Retail Transmission Service Rates;
- Wholesale Market Service Rate;
- Rural Rate Protection Charge;
- Standard Supply Service – Administrative Charge;
- MicroFIT Service Charge;
- Specific Service Charges; and
- Transformation and Primary Metering Allowances.[4]

2.2 Incremental Capital Module

The incremental capital module ("ICM") is intended to address the treatment of new capital investment needs that arise during the IRM plan term which are incremental to the materiality threshold defined below.

The eligibility criteria to recover amounts that are incremental to capital investment needs are included in section 2.5 of the *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, dated* July 14, 2008 and are reproduced below.

4 and any other allowances the Board may determine.

Criteria	Description
Materiality	The amounts must exceed the Board-defined materiality threshold and clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing.
Need	Amounts should be directly related to the claimed driver, which must be clearly non-discretionary. The amounts must be clearly outside of the base upon which rates were derived.
Prudence	The amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

2.2.1 ICM Materiality Threshold

The ICM materiality threshold is discussed in section 2.3 of the *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "Supplemental Report") EB-2007-0673.

The Board has determined that the following formula is to be used by a distributor to calculate the materiality threshold that will apply to it:

$$\textit{Threshold Value} = 1 + \left(\frac{RB}{d}\right) * (g + PCI * (1 + g)) + 20\%$$

Where:

RB = rate base included in base rates ($);

d = depreciation expense included in base rates ($);

g = distribution revenue change from load growth (%); and

PCI = price cap index (% inflation less productivity factor less stretch factor).

The values for "RB" and "d" are the Board-approved amounts in the distributor's base year rate decision.

The value for "g" is the % difference in distribution revenues between the most current complete year and the base year.

The following table provides an example of the calculation of the materiality threshold values.

An Illustration:

Assumptions:	RB	=	$100 million;
	d	=	$5 million;
	g	=	1.5% (0.015); and
	PCI	=	0.75% (0.0075).
Calculation:	$1+(\frac{100,000,000}{5,000,000})*(0.015+.0075*(1+0.015))+0.20=1.65$		
Result:	The materiality threshold (CAPEX/Depreciation) is 1.65 or 165%. That is, given the assumptions in this example, the Board expects the distributor to manage a CAPEX level of up to $8.26 million ($5 million * 1.65) before being eligible to apply to recover incremental amounts.		

2.2.2 Eligible Incremental Capital Amount

In the Supplemental Report, the Board determined that eligible incremental capital amount sought for recovery should be new capital in excess of the materiality threshold. The materiality threshold value, as calculated using the formula discussed in Section 2.2.1, establishes eligibility for incremental capital spending and also marks the base from which to calculate the maximum amount eligible for recovery. A distributor applying for recovery of incremental capital should calculate the maximum allowable capital amount by taking the difference between the 2013 total non-discretionary capital expenditure and the materiality threshold.

2.2.3 Application of the Half-Year Rule

The Board's general guidance on the application of the half-year rule is provided in the Supplemental Report. In this report the Board determined that the half-year rule should not apply so as not build a deficiency for the subsequent years of the IRM plan term. In a subsequent decision with respect to the application of the half-year rule in the context of an ICM, the Board decided that the half-year rule would apply in the final year of the IRM plan term[5]. The Board has adopted this as a clarification to the policy on ICM.

2.2.4 Revenue Requirement Calculation

When calculating the revenue requirement associated with the ICM, a distributor should use the following parameters:

- Cost of Capital
    - In the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, issued

[5] EB-2010-0130, Guelph Hydro Electric Systems Inc., *Decision and Order,* p. 15

December 20, 2006 (“2006 Report”) the Board outlined the transition to a single deemed capital structure of 60% debt and 40% equity. Since all distributors have completed the transition to a 60/40 debt-equity ratio, a distributor filing for an ICM adjustment shall use this deemed capital structure.

- On December 11, 2009 the Board issued the *Report of the Board on the Cost of Capital for Ontario’s Regulated Utilities* (the “2009 Report”). The 2009 Report sets out revised cost of capital parameters to be effected in cost of service applications. A distributor filing an ICM adjustment, shall use the last Board-approved cost of capital parameters determined during the distributor’s last rebasing application when calculating the revenue requirement associated with the ICM.

- PILS
  - Since currently known legislated tax changes from the level reflected in the Board-approved base rates for a distributor will be reflected in the IRM adjustments, a distributor filing for an ICM adjustment should apply the current tax rates when calculating the revenue requirement associated with the ICM.

- Working Capital Allowance (“WCA”)
  - A distributor filing an ICM adjustment shall use the last Board-approved WCA determined during the distributor’s last rebasing application when calculating the revenue requirement associated with the ICM.

2.2.5 ICM Filing Guidelines

The Board requires that a distributor requesting relief for incremental capital during the IRM3 plan term must include comprehensive evidence to support the claimed need, which should include the following:

- An analysis demonstrating that the materiality threshold test has been met and that the amounts will have a significant influence on the operation of the distributor;
- Justification that the amounts to be incurred will be prudent. This means that the distributor’s decision to incur the amounts represents the most cost-effective option (not necessarily least initial cost) for ratepayers;
- Justification that amounts being sought are directly related to the claimed cause, which must be clearly non-discretionary and clearly outside of the base upon which current rates were derived.

- Evidence that the incremental revenue requested will not be recovered through other means (e.g., it is not, in full or in part, included in base rates or being funded by the expansion of service to include new customers and other load growth);
- Details by project for the proposed capital spending plan for the test year segregated between discretionary and non-discretionary;
- A description of the proposed non-discretionary capital projects and expected in-service dates;
- Calculation of the revenue requirement associated with each proposed incremental non-discretionary capital project (i.e. the cost of capital, depreciation, and PILs);
- Calculation of revenue requirement offsets associated with each incremental non-discretionary projects due to revenue to be generated through other means (e.g. customer contributions in aid of construction);
- A description of the actions the distributor will take in the event that the Board does not approve the application.
- Calculation of a rate rider to recover the incremental revenue from each class and the rationale for the proposed approach.

2.2.6 ICM Reporting Requirements

A distributor that receives rate relief through this module will be required to report to the Board annually on the actual amounts spent. At the time of the next rebasing, the distributor will file a calculation of the amounts to be incorporated in rate base. At that time the Board will make a determination on the treatment of any difference between forecast and actual capital spending during the IRM plan term. Any overspending or underspending will be reviewed at the time of rebasing.

2.2.7 ICM Accounting Treatment

The distributor will record eligible ICM amounts in Account 1508, Other Regulatory Asset, sub-account Incremental Capital Expenditures, subject to the assets being used and useful. For incremental capital assets under construction, the normal accounting treatment will continue in the construction work in progress (“CWIP”) prior to these assets going into service and hence eligible for recording in the 1508 sub-account. The amortization of capital assets for the relevant accounting period will be recorded in a separate amortization account of the sub-account, Incremental Capital Expenditures. In addition, the revenues collected from the rate rider will be recorded in Account 1508, Other Regulatory Asset, sub-account, Incremental Capital Expenditures rate rider.

The distributor shall also record monthly carrying charges in sub-accounts Incremental Capital Expenditures and Incremental Capital Expenditures rate rider. Carrying charges amounts are calculated using simple interest applied to the monthly opening balances in the account and recorded in a separate sub-account of account 1508. The rate of interest shall be the rate prescribed by the Board for deferral and variance accounts for the respective quarterly period published in the Board's web site.

2.2.8 Rate Generator and Supplemental Filing Module for ICM

The supplemental filing module supporting the Rate Generator will assist the distributor in calculating the distributor's threshold. The distributor will then tabulate the value of its eligible non-discretionary investments and compare this to the threshold. Other calculation work forms will be provided to calculate the revenue requirement for each project proposed for inclusion in the ICM request in the supplemental filing module. Once all work forms are completed and listed in the supplemental module, the tabulated revenue requirement will be converted into a rate rider.

2.3 Z-factor Claims

Z-factors are intended to provide for unforeseen events outside of a distributor's management control. The cost to a distributor must be material and its causation clear. A distributor must follow the guidelines listed below when applying to the Board to recover the amounts that the distributor has recorded in a Board-approved deferral account related to a Z-factor claim.

2.3.1 Eligibility Criteria for Z-factor Amounts

The eligibility criteria for a request to recover amounts by way of a Z-factor are discussed in section 2.6 of the *Board's Report on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* – July 14, 2008, and are summarized in Table 1 below. In order for amounts to be considered for recovery by way of a Z-factor, the amounts must satisfy all three eligibility criteria set out in Table 1 below.

Table 1: Z-factor Amount Eligibility Criteria

Criteria	Description
Causation	Amounts should be directly related to the Z-factor event. The amount must be clearly outside of the base upon which rates were derived.
Materiality	The amounts must exceed the Board-defined materiality threshold and have a significant influence on the operation of the distributor; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements.
Prudence	The amount must have been prudently incurred. This means that the distributor's decision to incur the amount must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

2.3.2 Materiality Threshold

The following materiality thresholds will apply:

- $50,000 for a distributor with a distribution revenue requirement less than or equal to $10 million;
- 0.5% of distribution revenue requirement for a distributor with a revenue requirement greater than $10 million and less than or equal to $200 million; and
- $1 million for a distributor with a distribution revenue requirement of more than $200 million.

The materiality threshold must be met on an individual event basis in order for the relevant costs to be eligible for potential recovery.

2.3.3 Z-factor Filing Guidelines

A distributor must submit evidence that the costs incurred meet the three eligibility criteria outlined above. A distributor must also:

- Notify the Board by letter to the Board Secretary of all Z-factor events. Failure to notify the Board within six months of the event may result in disallowance of the claim.
- Apply to the Board for any cost recovery of amounts recorded in the Board-approved deferral account claimed under Z-factor treatment. This will allow the Board and any affected distributor the flexibility to address extraordinary events in a timely manner. Subsequently, the Board may review and prospectively adjust the amounts for which Z-factor treatment is claimed.
- Provide a clear demonstration that the management of the distributor could not have been able to plan and budget for the event and that the harm caused by the event is genuinely incremental to its experience or reasonable expectations.
- Demonstrate that the costs are incremental to those already being recovered in rates as part of ongoing business exposure risk.

2.3.4 Other Matters in Relation to Z-Factors

As part of its claim, a distributor must outline the manner in which it intends to allocate the incremental revenue requirement to the various customer rate classes, the rationale for the selected approach and a discussion of the merits of alternative allocation methods. Recovery will be through a rate rider[6]. The request must specify whether the rate rider(s) will apply on a fixed or variable basis or a combination thereof, and the

[6] See Appendix C

length of the disposition period and a rationale for this proposal. A detailed calculation of the rate rider(s) must be provided.

2.3.5 Z-factor Accounting Treatment

The distributor will record eligible Z-factor cost amounts in Account 1572, Extraordinary Event Costs, of the Board's Uniform System of Accounts (the "USoA") contained in the *Accounting Procedures Handbook* ("APH") for electricity distributors. Monthly carrying charges shall be recorded in Account 1572. Carrying charges are calculated using simple interest applied to the monthly opening balances in the account and recorded in a separate sub-account of this account. The rate of interest shall be the rate prescribed by the Board for deferral and variance accounts for the respective quarterly period published on the Board's web site.

2.4 Off-ramps

An off-ramp is based on a pre-defined set of conditions under which the IRM plan would be terminated or modified before its normal end-of-term date due to excessive over or under earnings.

For IRM3, the Board determined that the plan will include a trigger mechanism with an annual ROE dead band of ±300 basis points. When a distributor performs outside of this earnings dead band, a regulatory review may be initiated. A distributor will be required to report to the Board no later than 60 days after the company's receipt of its annual audited financial statements, in the event that the distributor's earnings falls short of or exceeds its ROE by 300 basis points. The Board will also monitor results filed by distributors as part of their reporting and record-keeping requirements. A review will be carried out by the Board to determine if further action by the Board is warranted. Any such review would be prospective in nature, and could result in modifications to the IRM3 plan, a termination of the IRM3 plan or the continuation of the IRM3 plan for that distributor.

2.5 Tax Changes

Under an IRM3, a 50/50 sharing[7] of the impact of currently known legislated tax changes as applied to the tax level reflected in the Board-approved base rates for a distributor applies. The calculated annual tax changes over the plan term will be allocated to customer rate classes on the basis of the most recent Board-approved base-year distribution revenue. These amounts will be collected from or refunded to customers each year of the plan term, over a 12-month period, through an explicit volumetric rate rider derived using annualized consumption by customer class underlying the Board-approved base rates.

[7] Supplemental Report of the Board on 3rd Generation Incentive Regulation – September 17, 2008

A shared tax saving workform will include a schedule for a distributor to complete, which will calculate the volumetric rate rider. Occasionally, the calculated rate riders for one or more rate classes may be negligible. In the event that the calculation for one or more rate classes results in volumetric rate riders of $0.0000 when rounded to the fourth decimal place, or is negligible, the distributor may request to record the total amount in USoA account 1595 for disposition in a future proceeding.

3.0 Implementation Matters

3.1 Deferral and Variance Account Balances

The *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Report* (the "EDDVAR Report") provides that during the IRM plan term, the distributor's Group 1 audited account balances will be reviewed and disposed if the preset disposition threshold of $0.001 per kWh (debit or credit) is exceeded. The onus is on the distributor to justify why any account balance in excess of the threshold should not be disposed.

Distributors must file in their application Group 1 balances as of December 31, 2011 to determine if the threshold has been exceeded. A continuity schedule, found on sheet 9 of the Rate Generator, must be completed as part of the application, regardless of whether or not the preset disposition threshold has been met.

Group 1 consists of the following USoA accounts:

- 1550 Low Voltage Account;
- 1580 RSVA Wholesale Market Service Charge Account;
- 1584 RSVA Retail Transmission Network Charges Account;
- 1586 RSVA Retail Transmission Connection Charge Account;
- 1588 RSVA Power Account;
- 1588 RSVA Global Adjustment Sub-Account;
- 1590 Recovery of Regulatory Asset Balances Account; and
- 1595 Disposition and Recovery/Refund of Regulatory Balances Account.

The EDDVAR Report states that the default disposition period to clear the Group 1 account balances by means of a rate rider should be one year. However, a distributor could propose a different disposition period to mitigate rate impacts or address any other applicable considerations, where appropriate.

The global adjustment sub-account captures the difference between the amounts billed (or estimated to be billed) to non-RPP customers by the distributor and the actual amount paid by the distributor to the IESO.

During the 2010, 2011, and 2012 EDR process, the Board determined that a separate rate rider included in the delivery component of the bill would apply prospectively to non-RPP customers to dispose of the global adjustment sub-account balances.

In March of 2012, the Board updated the APH. The Board revised Account 1588 RSVA Power, Sub-account Global Adjustment and established a separate account for the global adjustment, Account 1589, RSVA Global Adjustment, effective January 1, 2012. Since balances as of December 31, 2011 will be subject to the Board's review as part of the 2013 IRM application, this change will apply to 2014 rate applications only.

3.2 Revenue-to-Cost Ratio Adjustments

The Board's Decisions for some distributors' 2010, 2011 and 2012 cost of service rate applications prescribed a phase-in period to adjust the revenue-to-cost ratios. The Supplemental Filing Module and Rate Generator will include schedules for a distributor to effect revenue-to-cost ratio adjustments previously approved by the Board. The process will adjust base distribution rates before the application of the price cap adjustment.

3.3 Electricity Distribution Retail Transmission Service Rates

In preparing its application, the distributor should reference the Board's *Guideline G-2008-0001: Electricity Distribution Retail Transmission Service Rates,* October 22, 2008, and subsequent updates to the Uniform Transmission Rates ("UTRs").

The Board will provide a filing module to distributors to assist in calculating the distributor's class-specific RTSRs. The filing module will reflect the most recent UTRs approved by the Board (EB-2011-0268), issued on December 20, 2011 and effective January 1, 2012. Once any January 1, 2013 UTR adjustments are determined, Board staff will adjust each distributor's 2013 RTSR model and Rate Generator to incorporate these changes. Distributors will have an opportunity to comment on the accuracy of Board staff's updates as part of the draft Rate Order process.

3.4 Conservation and Demand Management ("CDM") Costs

The CDM Code was issued on September 16, 2010 and sets out obligations and requirements in relation to CDM activities after December 31, 2010. The CDM Code applies to CDM Programs that start on January 1, 2011 and end on December 31, 2014 or occur anytime in between those two dates. All electricity savings (kWh) and peak demand savings (kW) resulting from CDM Programs must also occur within that timeframe to be counted against a distributor's CDM Targets.

The Board expects that, going forward, most CDM funding for distributors for the 2012-2014 period, will be provided by the Ontario Power Authority ("OPA"). It is expected that a distributor will enter into contracts to deliver OPA-Contracted Province-Wide CDM Programs. If a distributor seeks to deliver programs not being offered through the OPA-Contracted Province-Wide Programs, it is able to apply for Board approval for programs that are in compliance with the rules set out in the Board's CDM Code and clarified in the April 26, 2012 Conservation and Demand Management Guidelines (EB-2012-0003) (CDM Guidelines). This will be funded through the global adjustment mechanism, and therefore should not be included in distribution rates.

3.4.1 Lost Revenue Adjustment Mechanism

The lost revenue adjustment mechanism ("LRAM") is a retrospective adjustment, which is designed to account for differences between the forecast revenue loss embedded in rates and the actual revenue loss.

On April 26, 2012, the Board issued updated CDM Guidelines. The CDM Guidelines were developed to provide more clarity on the CDM Code and what information needs to be filed in support of Board-Approved CDM program applications, as well as to provide updated details on the LRAM and the associated variance account for the 2011-2014 term.

3.4.2 LRAM Variance Account ("LRAMVA") for 2011 – 2014

For CDM programs delivered within the 2011 to 2014 term, the Board established Account 1568 as the LRAMVA to capture the variance between the Board-approved CDM forecast and the actual results at the customer rate class level. Accounting guidelines regarding the LRAMVA can be found in Appendix B of the 2012 CDM Guidelines. Distributors should refer to the CDM Guidelines for further details.

The distributor shall compare the Board-approved forecasted CDM related load forecast reduction to the actual CDM results. The variance calculated from this comparison shall be recorded in separate sub-accounts for the applicable customer rate classes.

3.4.3 Disposition of the LRAMVA

At a minimum, distributors must apply for the disposition of the balance in the LRAMVA as part of their COS applications. Distributors may apply for the disposition of the balance in the LRAMVA on an annual basis, as part of their IRM rate applications, if the balance is deemed significant by the applicant.

In support of its application for lost revenues distributors must file the following:

- A statement indicating that the distributor has used the most recent input assumptions available at the time of the program evaluation when calculating its

LRAM amount;

- A statement indicating that the distributor has relied on the most recent and appropriate final evaluation report from the OPA in support of its LRAM calculation;

- Separate tables for each rate class that shows the LRAM amounts requested by the year they are associated with and the year the lost revenues took place;

- LRAM calculations, determined by calculating the energy savings by customer class and valuing those energy savings using the distributor's Board-approved variable distribution charge appropriate to the class;

- A statement, and if applicable a table, that indicates if carrying charges are being requested on the LRAM amount;

- For Board-approved programs, a third party report, in accordance with the OPA's EM&V Protocols as set out in Section 6.1 of the CDM Code, that provides a review and verification of the LRAM calculations, including:

    - Confirmation of the use of correct input assumptions and LRAM calculations
    - Verified participation amounts
    - The net and gross kW and kWh impacts of each program and for each class, both gross and net of free riders, separated by year
    - Verification of any carrying charges requested; and

- For OPA Contracted Province-Wide Programs the distributor must provide documentation (i.e. final evaluation report from the OPA) of the distributor's results.

A separate third party review of the distributors OPA-Contracted Province-Wide CDM programs is not required.

3.4.4 LRAM and/or SSM for pre-2011 CDM activities

In Section 3.4.2 of Chapter 3 of the Filing Requirements, issued June 22, 2011, the Board stated that if a distributor does not file for the recovery of LRAM or SSM amounts in its 2012 rate application, it will forego the opportunity to recover LRAM or SSM for the legacy period of CDM activity (2005 – 2010).

The Board expects LRAM claims for pre-2011 CDM activities to have been completed with the 2012 rate applications, outside of persisting historical CDM impacts realized after 2010 for those distributors whose load forecast has not been updated as part of a cost of service application. SSM is not applicable for savings persisting from the legacy period.

In support of its application for persisting lost revenues from pre-2011 CDM programs, distributors must file the following:

- A statement confirming that the distributor's load forecast has not been updated as part of a cost of service application since the CDM programs, for which persistent lost revenue is sought, were implemented;

- A statement indicating that the distributor has used the most recent input assumptions available at the time of the program evaluation when calculating its LRAM amount;

- A statement indicating that the distributor has relied on the most recent and appropriate final evaluation report from the OPA in support of its LRAM calculation;

- Separate tables for each rate class that shows the LRAM amounts requested by the year they are associated with and the year the lost revenues took place;

- LRAM calculations, determined by calculating the energy savings by customer class and valuing those energy savings using the distributor's Board-approved variable distribution charge appropriate to the class;

- A statement, and if applicable a table, that indicates if carrying charges are being requested on the LRAM amount;

- A third party report that provides a review and verification of the LRAM calculations, including:

    - Confirmation of the use of correct input assumptions and LRAM calculation
    - Verified participation amounts
    - The net and gross kW and kWh impacts of each program and for each class, both gross and net of free riders, separated by year
    - Verification of any carrying charges requested.

3.5 Distribution System Plans - Filing under Deemed Conditions of Licence

The *Filing Requirements: Distribution System Plans - Filing under Deemed Conditions of Licence* (EB-2009-0397) revised on May 17, 2012 (originally issued on March 25, 2010), recognized that distributors may need additional funding for expenditures proposed in a GEA Plan between cost-of-service applications. For 2013 IRM applications, distributors may request the following:

- Renewable Generation Connection Funding Adder; and
- Smart Grid Funding Adder.

Where a distributor seeks a funding adder, sufficient information must be provided to allow the Board to assess the need for the mechanism and the nature and quantum of the costs to be collected from ratepayers and the basis for calculating the funding adder. The costs recovered through the funding adder will be subject to a prudence review in the first cost of service application following the implementation of the funding adder. A refund to ratepayers may be ordered if the Board find that the expenditures upon which the adder was based were not prudently incurred.

In the Distribution System Plan Filing Requirements, the Board created two additional deferral accounts to record the amounts collected from ratepayers through the funding adders:

- Account 1533: Renewable Generation Connection Funding Adder Deferral Account

  This account will record the revenues collected through a funding adder approved by the Board related to renewable generation connection projects. Separate sub-accounts shall be used to record any amounts collected from a distributor's ratepayers and any amounts received from the IESO (pursuant to the provincial pooling mechanism set out in 79.1 of the OEB Act) in respect of the projects.

- Account 1536: Smart Grid Funding Adder Deferral Account
  This account will record the revenue collected through a funding adder approved by the Board related to smart grid development.

3.6 Transition to International Financial Reporting Standards ("IFRS")

The Board provided general guidance on this topic in the *Report of the Board, Transition to IFRS,* issued on July 28, 2009 and in associated amendments available on the IFRS page of the Board's website (amendments are dated November 8, 2010 and April 30, 2012).

On June 13, 2011 an *Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment* (EB-2008-0408) (the "Addendum") was issued following a working group process. The Addendum sets out additional regulatory policy regarding the transition to IFRS in the circumstance where utilities rates are rebased using cost of service rate setting methods and where rates are subsequently set using an IRM. For distributors that rebased under CGAAP and are filing an IRM application, issues 1 and 2 in the Addendum are of particular relevance.

For those distributors who rebased under CGAAP and are filing an IRM application where a distributor seeks an ICM, and/or Z-factor treatment, the financial information supporting the rate adjustments must be provided under CGAAP. The adjustments to rates will also be made on the basis of CGAAP.

In addition, a reconciliation of the CGAAP-based financial information for an ICM or Z factor to the relevant information in the last annual RRR reporting under modified IFRS is required. Where the applicant has adopted IFRS for financial reporting, but has not yet made an annual RRR reporting under modified IFRS, the financial information mentioned above must be provided in both CGAAP and modified IFRS format, and a reconciliation provided between the two accounting standards. No third party assurance is required for the reconciliations, although an applicant can choose to file such assurance as part of its evidence supporting the reconciliation.

The Board authorized the creation of a generic IFRS transition PP&E deferral account, Account 1575, that the applicants must use to record differences arising as a result of accounting policy changes caused by the transition from CGAAP to MIFRS. In general, this account will be cleared at the first rebasing application under MIFRS.

Utilities that file and report under USGAAP (or another accounting standard) should, in general, read references to IFRS and MIFRS in the Filing Requirements to include USGAAP (or other alternate accounting standard). The deferral account authorized in Issue 2 of the Addendum may not be necessary for such utilities.

4.0 Specific Exclusions from IRM Applications

The IRM application process is intended to streamline the processing of a large volume of rate adjustment applications, and is therefore intended to be mechanistic in nature. For this reason, the Board has determined that the IRM process is not the appropriate venue by which a distributor should seek relief on issues which are substantially unique to an individual distributor or more complicated and potentially contentious. The following are examples of specific exclusions from the IRM rate application process:

- Rate Harmonization, other than that pursuant to a prior Board decision;
- Changes to revenue-to-cost ratios, other than pursuant to a prior Board decision;
- Loss Factor Changes;
- Re-setting of Specific Service Charges;
- Loss Carry Forward Adjustments to PILs/taxes; and
- Loss of Customer Load.

Exclusions from the IRM process are to be addressed in the distributor's next cost of service application. With respect to smart meter cost recovery, a distributor may elect to include this element as part of its 2013 IRM application if the timing of the smart meter cost recovery application coincides with the filing of the IRM application. Otherwise, the review of smart meter costs should be addressed in a separate (or stand alone) application.

Appendix A: Disposition of Residual Balance in USoA Account 1590 or 1595

The 2006 Regulatory Assets process disposed of all balances in the regulatory asset accounts as of December 31, 2004. The decisions for each distributor resulted in the disposition of the approved amounts by way of final rate riders and the transfer of the approved amounts to account 1590. Likewise, any deferral and variance account balances post December 31, 2004 that have been approved by the Board for disposition were disposed on a final basis, unless otherwise noted and should have been transferred to account 1595.

Accounts 1590 and 1595 are part of the Group 1 deferral and variance accounts as defined by the Board in the EDDVAR Report. Once the rate rider ceases, the residual principal balances and any interest carrying charges in these accounts would be cleared in an IRM application (where applicable) provided that the preset disposition threshold for the Group 1 accounts has been exceeded.

Appendix B: Application of Recoveries to Principal and Interest Carrying Charges Amounts in Account 1595

When final approval for disposition of deferral and variance account balances is received from the Board, the final approved amounts of principal and interest carrying charges is transferred to account 1595.

The cumulative principal balance transferred to account 1595 is drawn down by the rate rider recoveries, and interest carrying charges are applied to the principal balance net of recoveries.

The following approach is used for the application of recoveries (via rate riders) to the transferred amounts under two scenarios:

Scenario 1: Rate Rider ceases with Principal amount remaining.

If the rate rider ends before the principal is fully drawn down, the principal balance is held static and interest carrying charges are applied to the remaining principal balance. The approved rate rider flowing from the next application to dispose of deferral and variance accounts should include the remaining principal and interest carrying charges.

Scenario 2: Rate Rider ceases with no Principal amount remaining but with Interest Carrying Charges remaining.

The approved rate rider flowing from the next application to dispose of deferral and variance account balances should include the cumulative interest carrying charge amounts.

Appendix C: Rate Adder versus Rate Rider

Rate Adder

A rate adder (or funding adder) is a tool designed to provide advance funding on an interim basis to distributors for certain investments or expenses as prescribed by the Board and to mitigate or smooth the anticipated rate impact when recovery of these costs are approved by the Board. Approval of a rate adder does not constitute regulatory approval of any costs actually incurred. The prudence of such costs is examined, and the costs are approved in whole or in part, at the time at which the distributor brings the matter forward for regulatory review.

Rate adders are identified and listed separately on a distributor's Tariff of Rates and Charges and may have a sunset or termination date.

Rate Rider

A rate rider differs from a rate adder in that it is designed to recover or refund Board-approved amounts following a prudence review. Rate riders are identified and listed separately on a distributor's Tariff of Rates and Charges, with an explicit sunset or termination date.

Materiality for Rate Adders and Rate Riders

Rate adders and rate riders normally apply to one or more select rate classes on a fixed basis, a volumetric basis or a combination of both. A rate adder or rate rider is usually determined by dividing the Board-approved allocated amounts by the Board-approved forecast or historical energy use or demand.

Occasionally, the calculated rate adders or rate riders for one or more rate classes may be negligible. In the event where the calculation of one or more rate adder or rate rider results in volumetric rate riders of $(0.0000) when rounded to the fourth decimal place, , or are negligible the entire Board-approved amount for recovery or refund shall be recorded in a USoA account to be determined by the Board for disposition in a future rate setting.

Appendix J

Proposed Tariff of Rates and Charges to be effective May 1, 2013

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3RD Generation Incentive Regulation Model for 2013 Filers

Halton Hills Hydro Inc.

The following is a complete Tariff Schedule based on the information entered in this model. Please review.
Note: This worksheet is **unlocked** and the print margins, row heights, number formats, etc. can be adjusted.

Halton Hills Hydro Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 01, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0130

RESIDENTIAL - TIME OF USE SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning.
Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. The customer will be supplied at one service entrance only. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	12.36
Distribution Volumetric Rate	$/kWh	0.0116
Low Voltage Service Rate	$/kWh	0.0012
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kWh	0.0012
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kWh	(0.0018)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery (2012) – Effective until April 30, 2014	$/kWh	0.0007
Retail Transmission Rate - Network Service Rate	$/kWh	0.0057
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0046
Rate Rider for Recovery of Residual Historical Smart Meter Costs - effective July 1, 2012 - April 30, 2016	$	1.31
Rate Rider for Recovery of Stranded Meter Assets - effective July 1, 2012 - April 30, 2016	$	1.13

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	26.73
Distribution Volumetric Rate	$/kWh	0.0084
Low Voltage Service Rate	$/kWh	0.0011
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kWh	(0.0018)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery (2012) – Effective until April 30, 2014	$/kWh	0.0007
Retail Transmission Rate - Network Service Rate	$/kWh	0.0051
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0043
Rate Rider for Recovery of Residual Historical Smart Meter Costs - effective July 1, 2012 - April 30, 2016	$	1.38
Rate Rider for Recovery of Stranded Meter Assets - effective July 1, 2012 - April 30, 2016	$	1.46

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION

This classification applies to a non-residential customer with an average peak demand equal to or greater than 50 kW over the past twelve months, or is forecast to be equal to or greater than 50 kW, but less than 1,000 kW. For a new customer without prior billing history, the peak demand will be based on 90% of the proposed capacity or installed transformer. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	75.30
Distribution Volumetric Rate	$/kW	3.3580
Low Voltage Service Rate	$/kW	0.4734
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	1.5817
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kW	(0.7063)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery (2012) – Effective until April 30, 2014	$/kW	0.0490
Retail Transmission Rate - Network Service Rate	$/kW	2.2261
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8336

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE 1,000 TO 4,999 KW - INTERVAL METERS SERVICE CLASSIFICATION

This classification applies to a non-residential customer with an average peak demand equal to or greater than 1,000 kW over the past twelve months, or is forecast to be equal to or greater than 1,000 kW, but less than 5,000 kW. For a new customer without prior billing history, the peak demand will be based on 90% of the installed transformer. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	174.84
Distribution Volumetric Rate	$/kW	3.0786
Low Voltage Service Rate	$/kW	0.4734
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	1.9530
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kW	(0.7409)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery (2012) – Effective until April 30, 2014	$/kW	0.0108
Retail Transmission Rate - Network Service Rate	$/kW	2.2261
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8336

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, pedestrian X-Walk signals/beacons, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	6.56
Distribution Volumetric Rate	$/kWh	0.0043
Low Voltage Service Rate	$/kWh	0.0011
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kWh	0.0053
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kWh	(0.0016)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0051
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0043

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	4.92
Distribution Volumetric Rate	$/kW	18.6181
Low Voltage Service Rate	$/kW	0.3408
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	18.2482
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kW	(0.7438)
Retail Transmission Rate - Network Service Rate	$/kW	1.5881
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.3201

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

STREET LIGHTING SERVICE CLASSIFICATION

All services supplied to street lighting equipment owned by or operated for the Municipality, the Region or the Province of Ontario shall be classified as Street Lighting Service. Street Lighting plant, facilities, or equipment owned by the customer are subject to the Electrical Safety Authority (ESA) requirements and Halton Hills Hydro specifications. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	2.16
Distribution Volumetric Rate	$/kW	29.2086
Low Voltage Service Rate	$/kW	0.3338
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – Effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	0.2586
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2014	$/kW	(0.0754)
Retail Transmission Rate - Network Service Rate	$/kW	1.5808
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.2931

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

MICROFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.50)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration

Arrears certificate	$	15.00
Statement of Account	$	15.00
Pulling Post Dated Cheques	$	15.00
Duplicate Invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income Tax Letter	$	15.00
Notification charge	$	15.00
Account History	$	15.00
Credit Reference/credit check (plus credit agency costs)	$	15.00
Returned cheque (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Credit reference Letter		

Non-Payment of Account

Late Payment – per month	%	1.50
Late Payment – per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge – no disconnection – after regular hours	$	165.00
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect at meter – after regular hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Service call – customer owned equipment	$	30.00
Service call – after regular hours	$	165.00
Temporary service install & remove – overhead – no transformer	$	500.00
Temporary service installation and removal – underground – no transformer	$	300.00
Temporary Service – Install & remove – overhead – with transformer	$	1,000.00
Specific Charge for Access to the Power Poles - $/pole/year	$	22.35
Interval Meter Charge	$	20.00

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0602
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0496
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

Appendix K

Proposed Bill Impacts

Residential - Time of Use

Consumption	800	**kWh**
RPP Tier One	600	**kWh**
Load Factor		
Loss Factor	1.0602	

	CURRENT ESTIMATED BILL			PROPOSED ESTIMATED BILL						
	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total RPP Bill	% of Total TOU Bill
Energy First Tier (kWh)	600.00	0.0750	45.00	600.00	0.0750	45.00	0.00	0.00%	39.92%	
Energy Second Tier (kWh)	248.16	0.0880	21.84	248.16	0.0880	21.84	0.00	0.00%	19.37%	
TOU - Off Peak	542.82	0.0650	35.28	542.82	0.0650	35.28	0.00	0.00%		30.86%
TOU - Mid Peak	152.67	0.1000	15.27	152.67	0.1000	15.27	0.00	0.00%		13.35%
TOU - On Peak	152.67	0.1170	17.86	152.67	0.1170	17.86	0.00	0.00%		15.62%
Service Charge	1	12.25	12.25	1	12.36	12.36	0.11	0.90%	10.96%	10.81%
Service Charge Rate Rider(s)	1	2.30	2.30	1	2.44	2.44	0.14	6.09%	2.16%	2.13%
Distribution Volumetric Rate	800	0.0115	9.20	800	0.0116	9.28	0.08	0.87%	8.23%	8.12%
Low Voltage Volumetric Rate	800	0.0012	0.96	800	0.0012	0.96	0.00	0.00%	0.85%	0.84%
Distribution Volumetric Rate Rider(s)	800	(0.0012)	-0.96	800	(0.0011)	-0.88	0.08	(8.33)%	-0.78%	-0.77%
Total: Distribution			23.75			24.16	0.41	1.73%	21.43%	21.13%
Retail Transmission Rate - Network Service Rate	848.16	0.0057	4.83	848.16	0.0057	4.83	0.00	0.00%	4.28%	4.22%
Retail Transmission Rate - Line and Transformation Connection Service Rate	848.16	0.0045	3.82	848.16	0.0046	3.82	0.00	0.00%	3.39%	3.34%
Total: Retail Transmission			8.65			8.65	0.00	0.00%	7.67%	7.57%
Sub-Total: Delivery (Distribution and Retail Transmission)			**32.40**			**32.81**	**0.41**	**1.27%**	**29.11%**	**28.70%**
Wholesale Market Service Rate	848.16	0.0052	4.41	848.16	0.0052	4.41	0.00	0.00%	3.91%	3.86%
Rural Rate Protection Charge	848.16	0.0011	0.93	848.16	0.0011	0.93	0.00	0.00%	0.83%	0.82%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.22%	0.22%
Sub-Total: Regulatory			**5.59**			**5.59**	**0.00**	**0.00%**	**4.96%**	**4.89%**
Debt Retirement Charge (DRC)	**800.00**	**0.00700**	**5.60**	**800.00**	**0.0070**	**5.60**	**0.00**	**0.00%**	**4.97%**	**4.90%**
Total Bill on RPP (before taxes)			110.43			110.84	0.41	0.37%	98.33%	
HST		13%	14.36		13%	14.41	0.05	0.37%	12.78%	
Total Bill (including HST)			124.79			125.25	0.46	0.37%	111.11%	
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(12.48)		(10%)	(12.53)	(0.05)	0.37%	-11.11%	
Total Bill on RPP (including OCEB)			**112.31**			**112.73**	**0.42**	**0.37%**	**100.00%**	
Total Bill on TOU (before taxes)			112.01			112.42	0.41	0.37%		98.33%
HST		13%	14.56		13%	14.61	0.05	0.37%		12.78%
Total Bill (including HST)			126.57			127.03	0.46	0.37%		111.11%
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(12.66)		(10%)	(12.70)	(0.05)	0.37%		-11.11%
Total Bill on TOU (including OCEB)			**113.91**			**114.33**	**0.42**	**0.37%**		**100.00%**

Residential - Time of Use

Consumption	1,500	**kWh**
RPP Tier One	600	**kWh**
Load Factor		
Loss Factor	1.0602	

	CURRENT ESTIMATED BILL			PROPOSED ESTIMATED BILL						
	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total RPP Bill	% of Total TOU Bill
Energy First Tier (kWh)	600.00	0.0750	45.00	600.00	0.0750	45.00	0.00	0.00%	23.82%	
Energy Second Tier (kWh)	990.30	0.0880	87.15	990.30	0.0880	87.15	0.00	0.00%	46.14%	
TOU - Off Peak	1,017.79	0.0650	66.16	1,017.79	0.0650	66.16	0.00	0.00%		35.77%
TOU - Mid Peak	286.25	0.1000	28.63	286.25	0.1000	28.63	0.00	0.00%		15.48%
TOU - On Peak	286.25	0.1170	33.49	286.25	0.1170	33.49	0.00	0.00%		18.11%
Service Charge	1	12.25	12.25	1	12.36	12.36	0.11	0.90%	6.54%	6.68%
Service Charge Rate Rider(s)	1	2.30	2.30	1	2.44	2.44	0.14	6.09%	1.29%	1.32%
Distribution Volumetric Rate	800	0.0115	9.20	800	0.0116	9.28	0.08	0.87%	4.91%	5.02%
Low Voltage Volumetric Rate	800	0.0012	0.96	800	0.0012	0.96	0.00	0.00%	0.51%	0.52%
Distribution Volumetric Rate Rider(s)	800	(0.0012)	-0.96	800	(0.0011)	-0.88	0.08	(8.33)%	-0.47%	-0.48%
Total: Distribution			23.75			24.16	0.41	1.73%	12.79%	13.06%
Retail Transmission Rate - Network Service Rate	1,590.30	0.0057	4.83	1,590.30	0.0057	4.83	0.00	0.00%	2.56%	2.61%
Retail Transmission Rate - Line and Transformation Connection Service Rate	1,590.30	0.0045	3.82	1,590.30	0.0046	3.82	0.00	0.00%	2.02%	2.07%
Total: Retail Transmission			8.65			8.65	0.00	0.00%	4.58%	4.68%
Sub-Total: Delivery (Distribution and Retail Transmission)			**32.40**			**32.81**	**0.41**	**1.27%**	**17.37%**	**17.74%**
Wholesale Market Service Rate	1,590.30	0.0052	8.27	1,590.30	0.0052	8.27	0.00	0.00%	4.38%	4.47%
Rural Rate Protection Charge	1,590.30	0.0011	1.75	1,590.30	0.0011	1.75	0.00	0.00%	0.93%	0.95%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.13%	0.14%
Sub-Total: Regulatory			**10.27**			**10.27**	**0.00**	**0.00%**	**5.44%**	**5.55%**
Debt Retirement Charge (DRC)	**1,500.00**	**0.00700**	**10.50**	**1,500.00**	**0.0070**	**10.50**	**0.00**	**0.00%**	**5.56%**	**5.68%**
Total Bill on RPP (before taxes)			185.32			185.73	0.41	0.22%	98.33%	
HST		13%	24.09		13%	24.14	0.05	0.22%	12.78%	
Total Bill (including HST)			209.41			209.87	0.46	0.22%	111.11%	
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(20.94)		(10%)	(20.99)	(0.05)	0.22%	-11.11%	
Total Bill on RPP (including OCEB)			**188.47**			**188.88**	**0.42**	**0.22%**	**100.00%**	
Total Bill on TOU (before taxes)			181.44			181.85	0.41	0.23%		98.33%
HST		13%	23.59		13%	23.64	0.05	0.23%		12.78%
Total Bill (including HST)			205.03			205.49	0.46	0.23%		111.11%
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(20.50)		(10%)	(20.55)	(0.05)	0.23%		-11.11%
Total Bill on TOU (including OCEB)			**184.53**			**184.94**	**0.42**	**0.23%**		**100.00%**

Residential - Time of Use

Consumption	3,000	**kWh**
RPP Tier One	600	**kWh**
Load Factor		
Loss Factor	1.0602	

	CURRENT ESTIMATED BILL			PROPOSED ESTIMATED BILL						
	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total RPP Bill	% of Total TOU Bill
Energy First Tier (kWh)	600.00	0.0750	45.00	600.00	0.0750	45.00	0.00	0.00%	12.78%	
Energy Second Tier (kWh)	2,580.60	0.0880	227.09	2,580.60	0.0880	227.09	0.00	0.00%	64.50%	
TOU - Off Peak	2,035.58	0.0650	132.31	2,035.58	0.0650	132.31	0.00	0.00%		39.35%
TOU - Mid Peak	572.51	0.1000	57.25	572.51	0.1000	57.25	0.00	0.00%		17.03%
TOU - On Peak	572.51	0.1170	66.98	572.51	0.1170	66.98	0.00	0.00%		19.92%
Service Charge	1	12.25	12.25	1	12.36	12.36	0.11	0.90%	3.51%	3.68%
Service Charge Rate Rider(s)	1	2.30	2.30	1	2.44	2.44	0.14	6.09%	0.69%	0.73%
Distribution Volumetric Rate	800	0.0115	9.20	800	0.0116	9.28	0.08	0.87%	2.64%	2.76%
Low Voltage Volumetric Rate	800	0.0012	0.96	800	0.0012	0.96	0.00	0.00%	0.27%	0.29%
Distribution Volumetric Rate Rider(s)	800	(0.0012)	-0.96	800	(0.0011)	-0.88	0.08	(8.33)%	-0.25%	-0.26%
Total: Distribution			23.75			24.16	0.41	1.73%	6.86%	7.18%
Retail Transmission Rate - Network Service Rate	3,180.60	0.0057	4.83	3,180.60	0.0057	4.83	0.00	0.00%	1.37%	1.44%
Retail Transmission Rate - Line and Transformation Connection Service Rate	3,180.60	0.0045	3.82	3,180.60	0.0046	3.82	0.00	0.00%	1.08%	1.14%
Total: Retail Transmission			8.65			8.65	0.00	0.00%	2.46%	2.57%
Sub-Total: Delivery (Distribution and Retail Transmission)			**32.40**			**32.81**	**0.41**	**1.27%**	**9.32%**	**9.76%**
Wholesale Market Service Rate	3,180.60	0.0052	16.54	3,180.60	0.0052	16.54	0.00	0.00%	4.70%	4.92%
Rural Rate Protection Charge	3,180.60	0.0011	3.50	3,180.60	0.0011	3.50	0.00	0.00%	0.99%	1.04%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.07%	0.07%
Sub-Total: Regulatory			**20.29**			**20.29**	**0.00**	**0.00%**	**5.76%**	**6.03%**
Debt Retirement Charge (DRC)	**3,000.00**	**0.00700**	**21.00**	**3,000.00**	**0.0070**	**21.00**	**0.00**	**0.00%**	**5.96%**	**6.25%**
Total Bill on RPP (before taxes)			345.78			346.19	0.41	0.12%	98.33%	
HST		13%	44.95		13%	45.00	0.05	0.12%	12.78%	
Total Bill (including HST)			390.73			391.20	0.46	0.12%	111.11%	
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(39.07)		(10%)	(39.12)	(0.05)	0.12%	-11.11%	
Total Bill on RPP (including OCEB)			**351.66**			**352.08**	**0.42**	**0.12%**	**100.00%**	
Total Bill on TOU (before taxes)			330.23			330.64	0.41	0.12%		98.33%
HST		13%	42.93		13%	42.98	0.05	0.12%		12.78%
Total Bill (including HST)			373.17			373.63	0.46	0.12%		111.11%
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(37.32)		(10%)	(37.36)	(0.05)	0.12%		-11.11%
Total Bill on TOU (including OCEB)			**335.85**			**336.27**	**0.42**	**0.12%**		**100.00%**

General Service Less Than 50 kW

Consumption	500	**kWh**
RPP Tier One	600	**kWh**
Load Factor		
Loss Factor	1.0602	

	CURRENT ESTIMATED BILL			PROPOSED ESTIMATED BILL						
	Volume	**Current Rate ($)**	**Current Charge ($)**	**Volume**	**Proposed Rate ($)**	**Proposed Charge ($)**	**Change ($)**	**Change (%)**	**% of Total RPP Bill**	**% of Total TOU Bill**
Energy First Tier (kWh)	600.00	0.0750	45.00	600.00	0.0750	45.00	0.00	0.00%	52.25%	
Energy Second Tier (kWh)	-69.90	0.0880	-6.15	-69.90	0.0880	-6.15	0.00	0.00%	(7.14%)	
TOU - Off Peak	339.26	0.0650	22.05	339.26	0.0650	22.05	0.00	0.00%		24.47%
TOU - Mid Peak	95.42	0.1000	9.54	95.42	0.1000	9.54	0.00	0.00%		10.59%
TOU - On Peak	95.42	0.1170	11.16	95.42	0.1170	11.16	0.00	0.00%		12.39%
Service Charge	1	26.50	26.50	1	26.73	26.73	0.23	0.87%	31.03%	29.66%
Service Charge Rate Rider(s)	1	2.48	2.48	1	2.84	2.84	0.36	14.52%	3.30%	3.15%
Distribution Volumetric Rate	500	0.0083	4.15	500	0.0084	4.20	0.05	1.20%	4.88%	4.66%
Low Voltage Volumetric Rate	500	0.0011	0.55	500	0.0011	0.55	0.00	0.00%	0.64%	0.61%
Distribution Volumetric Rate Rider(s)	500	(0.0012)	-0.60	500	(0.0011)	-0.55	0.05	(8.33)%	-0.64%	-0.61%
Total: Distribution			33.08			33.77	0.69	2.09%	39.21%	37.48%
Retail Transmission Rate - Network Service Rate	530.10	0.0051	2.70	530.10	0.0051	2.70	0.00	0.00%	3.14%	3.00%
Retail Transmission Rate - Line and Transformation Connection Service Rate	530.10	0.0042	2.23	530.10	0.0043	2.28	0.05	2.38%	2.65%	2.53%
Total: Retail Transmission			4.93			4.98	0.05	1.01%	5.79%	5.53%
Sub-Total: Delivery (Distribution and Retail Transmission)			**38.01**			**38.75**	**0.74**	**1.95%**	**44.99%**	**43.01%**
Wholesale Market Service Rate	530.10	0.0052	2.76	530.10	0.0052	2.76	0.00	0.00%	3.20%	3.06%
Rural Rate Protection Charge	530.10	0.0011	0.58	530.10	0.0011	0.58	0.00	0.00%	0.68%	0.65%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.29%	0.28%
Sub-Total: Regulatory			**3.59**			**3.59**	**0.00**	0.00%	**4.17%**	**3.98%**
Debt Retirement Charge (DRC)	500.00	0.00700	3.50	500.00	0.0070	3.50	0.00	0.00%	**4.06%**	**3.88%**
Total Bill on RPP (before taxes)			83.95			84.69	0.74	0.89%	98.33%	
HST		13%	10.91		13%	11.01	0.10	0.89%	12.78%	
Total Bill (including HST)			94.86			95.70	0.84	0.89%	111.11%	
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(9.49)		(10%)	(9.57)	(0.08)	0.89%	-11.11%	
Total Bill on RPP (including OCEB)			**85.38**			**86.13**	**0.76**	0.89%	**100.00%**	
Total Bill on TOU (before taxes)			87.86			88.60	0.74	0.85%		98.33%
HST		13%	11.42		13%	11.52	0.10	0.85%		12.78%
Total Bill (including HST)			99.28			100.12	0.84	0.85%		111.11%
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(9.93)		(10%)	(10.01)	(0.08)	0.85%		-11.11%
Total Bill on TOU (including OCEB)			**89.35**			**90.11**	**0.76**	0.85%		**100.00%**

General Service Less Than 50 kW

Consumption	2,000	**kWh**
RPP Tier One	600	**kWh**
Load Factor		
Loss Factor	1.0602	

	CURRENT ESTIMATED BILL			PROPOSED ESTIMATED BILL						
	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total RPP Bill	% of Total TOU Bill
Energy First Tier (kWh)	600.00	0.0750	45.00	600.00	0.0750	45.00	0.00	0.00%	16.23%	
Energy Second Tier (kWh)	1,520.40	0.0880	133.80	1,520.40	0.0880	133.80	0.00	0.00%	48.24%	
TOU - Off Peak	1,357.06	0.0650	88.21	1,357.06	0.0650	88.21	0.00	0.00%		32.74%
TOU - Mid Peak	381.67	0.1000	38.17	381.67	0.1000	38.17	0.00	0.00%		14.17%
TOU - On Peak	381.67	0.1170	44.66	381.67	0.1170	44.66	0.00	0.00%		16.57%
Service Charge	1	26.50	26.50	1	26.73	26.73	0.23	0.87%	9.64%	9.92%
Service Charge Rate Rider(s)	1	2.48	2.48	1	2.84	2.84	0.36	14.52%	1.02%	1.05%
Distribution Volumetric Rate	2000	0.0083	16.60	2,000	0.0084	16.80	0.20	1.20%	6.06%	6.24%
Low Voltage Volumetric Rate	2000	0.0011	2.20	2,000	0.0011	2.20	0.00	0.00%	0.79%	0.82%
Distribution Volumetric Rate Rider(s)	2000	(0.0012)	-2.40	2,000	(0.0011)	-2.20	0.20	(8.33)%	-0.79%	-0.82%
Total: Distribution			45.38			46.37	0.99	2.18%	16.72%	17.21%
Retail Transmission Rate - Network Service Rate	2,120.40	0.0051	10.81	2,120.40	0.0051	10.81	0.00	0.00%	3.90%	4.01%
Retail Transmission Rate - Line and Transformation Connection Service Rate	2,120.40	0.0042	8.91	2,120.40	0.0043	9.12	0.21	2.38%	3.29%	3.38%
Total: Retail Transmission			19.72			19.93	0.21	1.06%	7.19%	7.40%
Sub-Total: Delivery (Distribution and Retail Transmission)			**65.10**			**66.30**	**1.20**	**1.85%**	**23.91%**	**24.61%**
Wholesale Market Service Rate	2,120.40	0.0052	11.03	2,120.40	0.0052	11.03	0.00	0.00%	3.98%	4.09%
Rural Rate Protection Charge	2,120.40	0.0011	2.33	2,120.40	0.0011	2.33	0.00	0.00%	0.84%	0.87%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.09%	0.09%
Sub-Total: Regulatory			**13.61**			**13.61**	**0.00**	0.00%	**4.91%**	**5.05%**
Debt Retirement Charge (DRC)	2,000.00	0.00700	14.00	2,000.00	0.0070	14.00	0.00	0.00%	**5.05%**	**5.20%**
Total Bill on RPP (before taxes)			271.50			272.71	1.20	0.44%	98.33%	
HST		13%	35.30		13%	35.45	0.16	0.44%	12.78%	
Total Bill (including HST)			306.80			308.16	1.36	0.44%	111.11%	
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(30.68)		(10%)	(30.82)	(0.14)	0.44%	-11.11%	
Total Bill on RPP (including OCEB)			**276.12**			**277.34**	**1.22**	0.44%	**100.00%**	
Total Bill on TOU (before taxes)			263.74			264.94	1.20	0.46%		98.33%
HST		13%	34.29		13%	34.44	0.16	0.46%		12.78%
Total Bill (including HST)			298.03			299.38	1.36	0.46%		111.11%
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(29.80)		(10%)	(29.94)	(0.14)	0.46%		-11.11%
Total Bill on TOU (including OCEB)			**268.22**			**269.45**	**1.22**	0.46%		**100.00%**

General Service Less Than 50 kW

Consumption	3,000	**kWh**
RPP Tier One	600	**kWh**
Load Factor		
Loss Factor	1.0602	

	CURRENT ESTIMATED BILL			PROPOSED ESTIMATED BILL						
	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total RPP Bill	% of Total TOU Bill
Energy First Tier (kWh)	600.00	0.0750	45.00	600.00	0.0750	45.00	0.00	0.00%	11.12%	
Energy Second Tier (kWh)	2,580.60	0.0880	227.09	2,580.60	0.0880	227.09	0.00	0.00%	56.10%	
TOU - Off Peak	2,035.58	0.0650	132.31	2,035.58	0.0650	132.31	0.00	0.00%		34.01%
TOU - Mid Peak	572.51	0.1000	57.25	572.51	0.1000	57.25	0.00	0.00%		14.72%
TOU - On Peak	572.51	0.1170	66.98	572.51	0.1170	66.98	0.00	0.00%		17.22%
Service Charge	1	26.50	26.50	1	26.73	26.73	0.23	0.87%	6.60%	6.87%
Service Charge Rate Rider(s)	1	2.48	2.48	1	2.84	2.84	0.36	14.52%	0.70%	0.73%
Distribution Volumetric Rate	3000	0.0083	24.90	3,000	0.0084	25.20	0.30	1.20%	6.23%	6.48%
Low Voltage Volumetric Rate	3000	0.0011	3.30	3,000	0.0011	3.30	0.00	0.00%	0.82%	0.85%
Distribution Volumetric Rate Rider(s)	3000	(0.0012)	-3.60	3,000	(0.0011)	-3.30	0.30	(8.33)%	-0.82%	-0.85%
Total: Distribution			53.58			54.77	1.19	2.22%	13.53%	14.08%
Retail Transmission Rate - Network Service Rate	3,180.60	0.0051	16.22	3,180.60	0.0051	16.22	0.00	0.00%	4.01%	4.17%
Retail Transmission Rate - Line and Transformation Connection Service Rate	3,180.60	0.0042	13.36	3,180.60	0.0043	13.68	0.32	2.38%	3.38%	3.52%
Total: Retail Transmission			29.58			29.90	0.32	1.08%	7.39%	7.69%
Sub-Total: Delivery (Distribution and Retail Transmission)			**83.16**			**84.67**	**1.51**	**1.81%**	**20.92%**	**21.77%**
Wholesale Market Service Rate	3,180.60	0.0052	16.54	3,180.60	0.0052	16.54	0.00	0.00%	4.09%	4.25%
Rural Rate Protection Charge	3,180.60	0.0011	3.50	3,180.60	0.0011	3.50	0.00	0.00%	0.86%	0.90%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.06%	0.06%
Sub-Total: Regulatory			**20.29**			**20.29**	**0.00**	0.00%	**5.01%**	**5.22%**
Debt Retirement Charge (DRC)	3,000.00	0.00700	21.00	3,000.00	0.0070	21.00	0.00	0.00%	**5.19%**	**5.40%**
Total Bill on RPP (before taxes)			396.54			398.05	1.51	0.38%	98.33%	
HST		13%	51.55		13%	51.75	0.20	0.38%	12.78%	
Total Bill (including HST)			448.09			449.79	1.70	0.38%	111.11%	
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(44.81)		(10%)	(44.98)	(0.17)	0.38%	-11.11%	
Total Bill on RPP (including OCEB)			**403.28**			**404.82**	**1.53**	0.38%	**100.00%**	
Total Bill on TOU (before taxes)			380.99			382.50	1.51	0.40%		98.33%
HST		13%	49.53		13%	49.73	0.20	0.40%		12.78%
Total Bill (including HST)			430.52			432.23	1.70	0.40%		111.11%
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(43.05)		(10%)	(43.22)	(0.17)	0.40%		-11.11%
Total Bill on TOU (including OCEB)			**387.47**			**389.01**	**1.53**	0.40%		**100.00%**

General Service 50 to 999 kW		
Consumption	500	kW
	100,000	kWh
RPP Tier One	600	kWh
Load Factor		
Loss Factor	1.0602	

	CURRENT ESTIMATED BILL			PROPOSED ESTIMATED BILL						
	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total RPP Bill	% of Total TOU Bill
Energy First Tier (kWh)	0.00	0.0750	0.00	0.00	0.0750	0.00	0.00	#DIV/0!	0.00%	
Energy Second Tier (kWh)	0.00	0.0880	0.00	0.00	0.0880	0.00	0.00	#DIV/0!	0.00%	
TOU - Off Peak	0.00	0.0650	0.00	0.00	0.0650	0.00	0.00	#DIV/0!		0.00%
TOU - Mid Peak	0.00	0.1000	0.00	0.00	0.1000	0.00	0.00	#DIV/0!		0.00%
TOU - On Peak	0.00	0.1170	0.00	0.00	0.1170	0.00	0.00	#DIV/0!		0.00%
Service Charge	1	74.64	74.64	1	75.30	75.30	0.66	0.88%	1.14%	1.14%
Service Charge Rate Rider(s)	1	(0.31)	-0.31	1	0.00	0.00	0.31	(100.00)%	0.00%	0.00%
Distribution Volumetric Rate	500	3.3287	1,664.35	500	3.3580	1,679.00	14.65	0.88%	25.39%	25.39%
Low Voltage Volumetric Rate	500	0.4734	236.70	500	0.4734	236.70	0.00	0.00%	3.58%	3.58%
Distribution Volumetric Rate Rider(s)	500	0.9114	455.70	500	0.9244	462.20	6.50	1.43%	6.99%	6.99%
Total: Distribution			2,431.08			2,453.20	22.12	0.91%	37.10%	37.10%
Retail Transmission Rate - Network Service Rate	500.00	2.2257	1,112.85	500.00	2.2261	1,113.05	0.20	0.02%	16.83%	16.83%
Retail Transmission Rate - Line and Transformation Connection Service Rate	500.00	1.7975	898.75	500.00	1.8336	916.80	18.05	2.01%	13.87%	13.87%
Total: Retail Transmission			2,011.60			2,029.85	18.25	0.91%	30.70%	30.70%
Sub-Total: Delivery (Distribution and Retail Transmission)			**4,442.68**			**4,483.05**	**40.37**	**0.91%**	**67.80%**	**67.80%**
Wholesale Market Service Rate	106,020.00	0.0052	551.30	106,020.00	0.0052	551.30	0.00	0.00%	8.34%	8.34%
Rural Rate Protection Charge	106,020.00	0.0011	116.62	106,020.00	0.0011	116.62	0.00	0.00%	1.76%	1.76%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%	0.00%
Sub-Total: Regulatory			**668.18**			**668.18**	**0.00**	0.00%	**10.11%**	**10.11%**
Debt Retirement Charge (DRC)	100,000.00	0.00700	700.00	100,000.00	0.0070	700.00	0.00	0.00%	**10.59%**	**10.59%**
Total Bill on RPP (before taxes)			5,810.86			5,851.23	40.37	0.69%	88.50%	
HST		13%	755.41		13%	760.66	5.25	0.69%	11.50%	
Total Bill (including HST)			6,566.27			6,611.89	45.62	0.69%	100.00%	
Ontario Clean Energy Benefit (OCEB)			0.00			0.00	0.00	#DIV/0!	0.00%	
Total Bill on RPP (including OCEB)			**6,566.27**			**6,611.89**	**45.62**	0.69%	**100.00%**	
Total Bill on TOU (before taxes)			5,810.86			5,851.23	40.37	0.69%		88.50%
HST		13%	755.41		13%	760.66	5.25	0.69%		11.50%
Total Bill (including HST)			6,566.27			6,611.89	45.62	0.69%		100.00%
Ontario Clean Energy Benefit (OCEB)			0.00			0.00	0.00	#DIV/0!		0.00%
Total Bill on TOU (including OCEB)			**6,566.27**			**6,611.89**	**45.62**	0.69%		**100.00%**

General Service 50 to 999 kW		
Consumption	750	kW
	200,000	kWh
RPP Tier One	600	kWh
Load Factor		
Loss Factor	1.0602	

	CURRENT ESTIMATED BILL			PROPOSED ESTIMATED BILL						
	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total RPP Bill	% of Total TOU Bill
Energy First Tier (kWh)	0.00	0.0750	0.00	0.00	0.0750	0.00	0.00	#DIV/0!	0.00%	
Energy Second Tier (kWh)	0.00	0.0880	0.00	0.00	0.0880	0.00	0.00	#DIV/0!	0.00%	
TOU - Off Peak	0.00	0.0650	0.00	0.00	0.0650	0.00	0.00	#DIV/0!		0.00%
TOU - Mid Peak	0.00	0.1000	0.00	0.00	0.1000	0.00	0.00	#DIV/0!		0.00%
TOU - On Peak	0.00	0.1170	0.00	0.00	0.1170	0.00	0.00	#DIV/0!		0.00%
Service Charge	1	74.64	74.64	1	75.30	75.30	0.66	0.88%	0.71%	0.71%
Service Charge Rate Rider(s)	1	(0.31)	-0.31	1	0.00	0.00	0.31	(100.00)%	0.00%	0.00%
Distribution Volumetric Rate	750	3.3287	2,496.53	750	3.3580	2,518.50	21.97	0.88%	23.65%	23.65%
Low Voltage Volumetric Rate	750	0.4734	355.05	750	0.4734	355.05	0.00	0.00%	3.33%	3.33%
Distribution Volumetric Rate Rider(s)	750	0.9114	683.55	750	0.9244	693.30	9.75	1.43%	6.51%	6.51%
Total: Distribution			3,609.46			3,642.15	32.70	0.91%	34.20%	34.20%
Retail Transmission Rate - Network Service Rate	750.00	2.2257	1,669.28	750.00	2.2261	1,669.58	0.30	0.02%	15.68%	15.68%
Retail Transmission Rate - Line and Transformation Connection Service Rate	750.00	1.7975	1,348.13	750.00	1.8336	1,375.20	27.07	2.01%	12.92%	12.92%
Total: Retail Transmission			3,017.40			3,044.78	27.38	0.91%	28.59%	28.59%
Sub-Total: Delivery (Distribution and Retail Transmission)			**6,626.86**			**6,686.93**	**60.07**	**0.91%**	**62.80%**	**62.80%**
Wholesale Market Service Rate	212,040.00	0.0052	1,102.61	212,040.00	0.0052	1,102.61	0.00	0.00%	10.36%	10.36%
Rural Rate Protection Charge	212,040.00	0.0011	233.24	212,040.00	0.0011	233.24	0.00	0.00%	2.19%	2.19%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%	0.00%
Sub-Total: Regulatory			**1,336.10**			**1,336.10**	**0.00**	0.00%	**12.55%**	**12.55%**
Debt Retirement Charge (DRC)	200,000.00	0.00700	1,400.00	200,000.00	0.0070	1,400.00	0.00	0.00%	**13.15%**	**13.15%**
Total Bill on RPP (before taxes)			9,362.96			9,423.03	60.07	0.64%	88.50%	
HST		13%	1,217.18		13%	1,224.99	7.81	0.64%	11.50%	
Total Bill (including HST)			10,580.14			10,648.02	67.88	0.64%	100.00%	
Ontario Clean Energy Benefit (OCEB)			0.00			0.00	0.00	#DIV/0!	0.00%	
Total Bill on RPP (including OCEB)			**10,580.14**			**10,648.02**	**67.88**	0.64%	**100.00%**	
Total Bill on TOU (before taxes)			9,362.96			9,423.03	60.07	0.64%		88.50%
HST		13%	1,217.18		13%	1,224.99	7.81	0.64%		11.50%
Total Bill (including HST)			10,580.14			10,648.02	67.88	0.64%		100.00%
Ontario Clean Energy Benefit (OCEB)			0.00			0.00	0.00	#DIV/0!		0.00%
Total Bill on TOU (including OCEB)			**10,580.14**			**10,648.02**	**67.88**	0.64%		**100.00%**

General Service 1,000 to 4,999 kW - Interval Meters		
Consumption	1,000	kW
	500,000	kWh
RPP Tier One	600	kWh
Load Factor		
Loss Factor	1.0602	

	CURRENT ESTIMATED BILL			PROPOSED ESTIMATED BILL						
	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total RPP Bill	% of Total TOU Bill
Energy First Tier (kWh)	0.00	0.0750	0.00	0.00	0.0750	0.00	0.00	#DIV/0!	0.00%	
Energy Second Tier (kWh)	0.00	0.0880	0.00	0.00	0.0880	0.00	0.00	#DIV/0!	0.00%	
TOU - Off Peak	0.00	0.0650	0.00	0.00	0.0650	0.00	0.00	#DIV/0!		0.00%
TOU - Mid Peak	0.00	0.1000	0.00	0.00	0.1000	0.00	0.00	#DIV/0!		0.00%
TOU - On Peak	0.00	0.1170	0.00	0.00	0.1170	0.00	0.00	#DIV/0!		0.00%
Service Charge	1	173.31	173.31	1	174.84	174.84	1.53	0.88%	0.98%	0.98%
Service Charge Rate Rider(s)	1	0.00	0.00	1	0.00	0.00	0.00	#DIV/0!	0.00%	0.00%
Distribution Volumetric Rate	1000	3.0517	3,051.70	1,000	3.0786	3,078.60	26.90	0.88%	17.19%	17.19%
Low Voltage Volumetric Rate	1000	0.4734	473.40	1,000	0.4734	473.40	0.00	0.00%	2.64%	2.64%
Distribution Volumetric Rate Rider(s)	1000	1.1121	1,112.10	1,000	1.2229	1,222.90	110.80	9.96%	6.83%	6.83%
Total: Distribution			4,810.51			4,949.74	139.23	2.89%	27.64%	27.64%
Retail Transmission Rate - Network Service Rate	1,000	2.2257	2,225.70	1,000	2.2261	2,226.10	0.40	0.02%	12.43%	12.43%
Retail Transmission Rate - Line and Transformation Connection Service Rate	1,000	1.7975	1,797.50	1,000	1.8336	1,833.60	36.10	2.01%	10.24%	10.24%
Total: Retail Transmission			4,023.20			4,059.70	36.50	0.91%	22.67%	22.67%
Sub-Total: Delivery (Distribution and Retail Transmission)			**8,833.71**			**9,009.44**	**175.73**	**1.99%**	**50.30%**	**50.30%**
Wholesale Market Service Rate	530,100	0.0052	2,756.52	530,100	0.0052	2,756.52	0.00	0.00%	15.39%	15.39%
Rural Rate Protection Charge	530,100	0.0011	583.11	530,100	0.0011	583.11	0.00	0.00%	3.26%	3.26%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%	0.00%
Sub-Total: Regulatory			**3,339.88**			**3,339.88**	**0.00**	0.00%	**18.65%**	**18.65%**
Debt Retirement Charge (DRC)	500,000	0.00700	3,500.00	500,000	0.0070	3,500.00	0.00	0.00%	**19.54%**	**19.54%**
Total Bill on RPP (before taxes)			15,673.59			15,849.32	175.73	1.12%	88.50%	
HST		13%	2,037.57		13%	2,060.41	22.84	1.12%	11.50%	
Total Bill (including HST)			17,711.16			17,909.73	198.57	1.12%	100.00%	
Ontario Clean Energy Benefit (OCEB)			0.00			0.00	0.00	#DIV/0!	0.00%	
Total Bill on RPP (including OCEB)			**17,711.16**			**17,909.73**	**198.57**	1.12%	**100.00%**	
Total Bill on TOU (before taxes)			15,673.59			15,849.32	175.73	1.12%		88.50%
HST		13%	2,037.57		13%	2,060.41	22.84	1.12%		11.50%
Total Bill (including HST)			17,711.16			17,909.73	198.57	1.12%		100.00%
Ontario Clean Energy Benefit (OCEB)			0.00			0.00	0.00	#DIV/0!		0.00%
Total Bill on TOU (including OCEB)			**17,711.16**			**17,909.73**	**198.57**	1.12%		**100.00%**

General Service 1,000 to 4,999 kW - Interval Meters		
Consumption	2,500	kW
	1,000,000	kWh
RPP Tier One	600	kWh
Load Factor		
Loss Factor	1.0602	

	CURRENT ESTIMATED BILL			PROPOSED ESTIMATED BILL						
	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total RPP Bill	% of Total TOU Bill
Energy First Tier (kWh)	0.00	0.0750	0.00	0.00	0.0750	0.00	0.00	#DIV/0!	0.00%	
Energy Second Tier (kWh)	0.00	0.0880	0.00	0.00	0.0880	0.00	0.00	#DIV/0!	0.00%	
TOU - Off Peak	0.00	0.0650	0.00	0.00	0.0650	0.00	0.00	#DIV/0!		0.00%
TOU - Mid Peak	0.00	0.1000	0.00	0.00	0.1000	0.00	0.00	#DIV/0!		0.00%
TOU - On Peak	0.00	0.1170	0.00	0.00	0.1170	0.00	0.00	#DIV/0!		0.00%
Service Charge	1	173.31	173.31	1	174.84	174.84	1.53	0.88%	0.43%	0.43%
Service Charge Rate Rider(s)	1	0.00	0.00	1	0.00	0.00	0.00	#DIV/0!	0.00%	0.00%
Distribution Volumetric Rate	2500	3.0517	7,629.25	2,500	3.0786	7,696.50	67.25	0.88%	18.95%	18.95%
Low Voltage Volumetric Rate	2500	0.4734	1,183.50	2,500	0.4734	1,183.50	0.00	0.00%	2.91%	2.91%
Distribution Volumetric Rate Rider(s)	2500	1.1121	2,780.25	2,500	1.2229	3,057.25	277.00	9.96%	7.53%	7.53%
Total: Distribution			11,766.31			12,112.09	345.78	2.94%	29.82%	29.82%
Retail Transmission Rate - Network Service Rate	2,500	2.2257	5,564.25	2,500	2.2261	5,565.25	1.00	0.02%	13.70%	13.70%
Retail Transmission Rate - Line and Transformation Connection Service Rate	2,500	1.7975	4,493.75	2,500	1.8336	4,584.00	90.25	2.01%	11.29%	11.29%
Total: Retail Transmission			10,058.00			10,149.25	91.25	0.91%	24.99%	24.99%
Sub-Total: Delivery (Distribution and Retail Transmission)			**21,824.31**			**22,261.34**	**437.03**	**2.00%**	**54.81%**	**54.81%**
Wholesale Market Service Rate	1,060,200	0.0052	5,513.04	1,060,200	0.0052	5,513.04	0.00	0.00%	13.57%	13.57%
Rural Rate Protection Charge	1,060,200	0.0011	1,166.22	1,060,200	0.0011	1,166.22	0.00	0.00%	2.87%	2.87%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%	0.00%
Sub-Total: Regulatory			**6,679.51**			**6,679.51**	**0.00**	0.00%	**16.45%**	**16.45%**
Debt Retirement Charge (DRC)	1,000,000	0.00700	7,000.00	1,000,000	0.0070	7,000.00	0.00	0.00%	**17.24%**	**17.24%**
Total Bill on RPP (before taxes)			35,503.82			35,940.85	437.03	1.23%	88.50%	
HST		13%	4,615.50		13%	4,672.31	56.81	1.23%	11.50%	
Total Bill (including HST)			40,119.32			40,613.16	493.84	1.23%	100.00%	
Ontario Clean Energy Benefit (OCEB)			0.00			0.00	0.00	#DIV/0!	0.00%	
Total Bill on RPP (including OCEB)			**40,119.32**			**40,613.16**	**493.84**	1.23%	**100.00%**	
Total Bill on TOU (before taxes)			35,503.82			35,940.85	437.03	1.23%		88.50%
HST		13%	4,615.50		13%	4,672.31	56.81	1.23%		11.50%
Total Bill (including HST)			40,119.32			40,613.16	493.84	1.23%		100.00%
Ontario Clean Energy Benefit (OCEB)			0.00			0.00	0.00	#DIV/0!		0.00%
Total Bill on TOU (including OCEB)			**40,119.32**			**40,613.16**	**493.84**	1.23%		**100.00%**

Unmetered Scattered Load

Consumption	100	**kWh**
RPP Tier One	600	**kWh**
Load Factor		
Loss Factor	1.0602	

	CURRENT ESTIMATED BILL			PROPOSED ESTIMATED BILL						
	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total RPP Bill	% of Total TOU Bill
Energy First Tier (kWh)	106.02	0.0750	7.95	106.02	0.0750	7.95	0.00	0.00%	44.66%	
Energy Second Tier (kWh)	0.00	0.0880	0.00	0.00	0.0880	0.00	0.00	#DIV/0!	0.00%	
TOU - Off Peak	67.85	0.0650	4.41	67.85	0.0650	4.41	0.00	0.00%		23.95%
TOU - Mid Peak	19.08	0.1000	1.91	19.08	0.1000	1.91	0.00	0.00%		10.36%
TOU - On Peak	19.08	0.1170	2.23	19.08	0.1170	2.23	0.00	0.00%		12.13%
Service Charge	1	6.50	6.50	1	6.56	6.56	0.06	0.92%	36.85%	35.63%
Service Charge Rate Rider(s)	1	(1.24)	-1.24	1	0.00	0.00	1.24	(100.00)%	0.00%	0.00%
Distribution Volumetric Rate	100	0.0043	0.43	100	0.0043	0.43	0.00	0.00%	2.42%	2.34%
Low Voltage Volumetric Rate	100	0.0011	0.11	100	0.0011	0.11	0.00	0.00%	0.62%	0.60%
Distribution Volumetric Rate Rider(s)	100	(0.0024)	-0.24	100	(0.0016)	-0.16	0.08	(33.33)%	-0.90%	-0.87%
Total: Distribution			5.56			6.94	1.38	24.82%	38.98%	37.69%
Retail Transmission Rate - Network Service Rate	106.02	0.0051	0.54	106.02	0.0051	0.54	0.00	0.00%	3.04%	2.94%
Retail Transmission Rate - Line and Transformation Connection Service Rate	106.02	0.0042	0.45	106.02	0.0043	0.46	0.01	2.38%	2.56%	2.48%
Total: Retail Transmission			0.99			1.00	0.01	1.01%	5.60%	5.41%
Sub-Total: Delivery (Distribution and Retail Transmission)			**6.55**			**7.94**	**1.39**	**21.24%**	**44.58%**	**43.10%**
Wholesale Market Service Rate	106.02	0.0052	0.55	106.02	0.0052	0.55	0.00	0.00%	3.10%	2.99%
Rural Rate Protection Charge	106.02	0.0011	0.12	106.02	0.0011	0.12	0.00	0.00%	0.66%	0.63%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	1.40%	1.36%
Sub-Total: Regulatory			**0.92**			**0.92**	**0.00**	0.00%	**5.16%**	**4.98%**
Debt Retirement Charge (DRC)	100.00	0.00700	0.70	100.00	0.0070	0.70	0.00	0.00%	**3.93%**	**3.80%**
Total Bill on RPP (before taxes)			16.12			17.51	1.39	8.63%	98.33%	
HST		13%	2.10		13%	2.28	0.18	8.63%	12.78%	
Total Bill (including HST)			18.21			19.78	1.57	8.63%	111.11%	
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(1.82)		(10%)	(1.98)	(0.16)	8.63%	-11.11%	
Total Bill on RPP (including OCEB)			**16.39**			**17.80**	**1.41**	8.63%	**100.00%**	
Total Bill on TOU (before taxes)			16.72			18.11	1.39	8.32%		98.33%
HST		13%	2.17		13%	2.35	0.18	8.32%		12.78%
Total Bill (including HST)			18.89			20.46	1.57	8.32%		111.11%
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(1.89)		(10%)	(2.05)	(0.16)	8.32%		-11.11%
Total Bill on TOU (including OCEB)			**17.00**			**18.41**	**1.41**	8.32%		**100.00%**

Sentinel Lighting		
Consumption	10	kWh
	1	kW
RPP Tier One	600	kWh
Load Factor		
Loss Factor	1.0602	

	CURRENT ESTIMATED BILL			PROPOSED ESTIMATED BILL						
	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total RPP Bill	% of Total TOU Bill
Energy First Tier (kWh)	10.60	0.0750	0.80	10.60	0.0750	0.80	0.00	0.00%	1.72%	
Energy Second Tier (kWh)	0.00	0.0880	0.00	0.00	0.0880	0.00	0.00	#DIV/0!	0.00%	
TOU - Off Peak	6.79	0.0650	0.44	6.79	0.0650	0.44	0.00	0.00%		0.95%
TOU - Mid Peak	1.91	0.1000	0.19	1.91	0.1000	0.19	0.00	0.00%		0.41%
TOU - On Peak	1.91	0.1170	0.22	1.91	0.1170	0.22	0.00	0.00%		0.48%
Service Charge	1	4.88	4.88	1	4.92	4.92	0.04	0.82%	10.64%	10.62%
Service Charge Rate Rider(s)	1	0.44	0.44	1	0.00	0.00	(0.44)	(100.00)%	0.00%	0.00%
Distribution Volumetric Rate	1.00	18.4557	18.46	1.00	18.6181	18.62	0.16	0.88%	40.26%	40.21%
Low Voltage Volumetric Rate	1.00	0.3408	0.34	1.00	0.3408	0.34	0.00	0.00%	0.74%	0.74%
Distribution Volumetric Rate Rider(s)	1.00	19.1742	19.17	1.00	17.5044	17.50	(1.67)	(8.71)%	37.85%	37.80%
Total: Distribution			43.29			41.38	(1.91)	(4.41)%	89.48%	89.37%
Retail Transmission Rate - Network Service Rate	1.00	1.5878	1.59	1.00	1.5881	1.59	0.00	0.00%	3.43%	3.43%
Retail Transmission Rate - Line and Transformation Connection	1.00	1.2941	1.29	1.00	1.3201	1.32	0.21	16.23%	2.85%	2.85%
Total: Retail Transmission			2.88			2.91	0.03	1.04%	6.29%	6.28%
Sub-Total: Delivery (Distribution and Retail Transmission)			**46.17**			**44.29**	**(1.88)**	**(4.07%)**	**95.77%**	**95.65%**
Wholesale Market Service Rate	10.60	0.0052	0.06	10.60	0.0052	0.06	0.00	0.00%	0.12%	0.12%
Rural Rate Protection Charge	10.60	0.0011	0.01	10.60	0.0011	0.01	0.00	0.00%	0.03%	0.03%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.54%	0.54%
Sub-Total: Regulatory			**0.32**			**0.32**	**0.00**	0.00%	**0.69%**	**0.68%**
Debt Retirement Charge (DRC)	10.00	0.00700	0.07	10.00	0.0070	0.07	0.00	0.00%	**0.15%**	**0.15%**
Total Bill on RPP (before taxes)			47.35			45.47	(1.88)	(3.97)%	98.33%	
HST		13%	6.16		13%	5.91	(0.24)	(3.97)%	12.78%	
Total Bill (including HST)			53.51			51.38	(2.13)	(3.97)%	111.11%	
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(5.35)		(10%)	(5.14)	0.21	(3.97)%	-11.11%	
Total Bill on RPP (including OCEB)			**48.16**			**46.25**	**(1.91)**	(3.97)%	**100.00%**	
Total Bill on TOU (before taxes)			47.41			45.53	(1.88)	(3.97)%		98.33%
HST		13%	6.16		13%	5.92	(0.24)	(3.97)%		12.78%
Total Bill (including HST)			53.58			51.45	(2.13)	(3.97)%		111.11%
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(5.36)		(10%)	(5.15)	0.21	(3.97)%		-11.11%
Total Bill on TOU (including OCEB)			**48.22**			**46.31**	**(1.91)**	(3.97)%		**100.00%**

Street Lighting		
Consumption	641	kW
	200,000	kWh
RPP Tier One		kWh
Load Factor		
Loss Factor	1.0602	

	CURRENT ESTIMATED BILL			PROPOSED ESTIMATED BILL						
	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total RPP Bill	% of Total TOU Bill
Energy First Tier (kWh)	0.00	0.0750	0.00	0.00	0.0750	0.00	0.00	#DIV/0!	0.00%	
Energy Second Tier (kWh)	0.00	0.0880	0.00	0.00	0.0880	0.00	0.00	#DIV/0!	0.00%	
TOU - Off Peak	0.00	0.0650	0.00	0.00	0.0650	0.00	0.00	#DIV/0!		0.00%
TOU - Mid Peak	0.00	0.1000	0.00	0.00	0.1000	0.00	0.00	#DIV/0!		0.00%
TOU - On Peak	0.00	0.1170	0.00	0.00	0.1170	0.00	0.00	#DIV/0!		0.00%
Service Charge	4417	2.14	9,452.38	4417	2.16	9,540.72	88.34	0.93%	25.45%	25.45%
Service Charge Rate Rider(s)	4417	(0.03)	-132.51	4,417	0.00	0.00	132.51	(100.00)%	0.00%	0.00%
Distribution Volumetric Rate	641	28.9538	18,559.39	641	29.2086	18,722.71	163.33	0.88%	49.95%	49.95%
Low Voltage Volumetric Rate	641	0.3338	213.97	641	0.3338	213.97	0.00	0.00%	0.57%	0.57%
Distribution Volumetric Rate Rider(s)	641	(0.2547)	-163.26	641	0.1832	117.43	280.69	(171.93)%	0.31%	0.31%
Total: Distribution			27,929.96			28,594.83	664.87	2.38%	76.28%	76.28%
Retail Transmission Rate - Network Service Rate	641.00	1.5805	1,013.10	641.00	1.5808	1,013.29	0.19	0.02%	2.70%	2.70%
Retail Transmission Rate - Line and Transformation Connection Service Rate	641.00	1.2676	812.53	641.00	1.2931	828.88	16.35	2.01%	2.21%	2.21%
Total: Retail Transmission			1,825.63			1,842.17	16.54	0.91%	4.91%	4.91%
Sub-Total: Delivery (Distribution and Retail Transmission)			**29,755.59**			**30,437.00**	**681.41**	**2.29%**	**81.20%**	**81.20%**
Wholesale Market Service Rate	212,040.00	0.0052	1,102.61	212,040.00	0.0052	1,102.61	0.00	0.00%	2.94%	2.94%
Rural Rate Protection Charge	212,040.00	0.0011	233.24	212,040.00	0.0011	233.24	0.00	0.00%	0.62%	0.62%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%	0.00%
Sub-Total: Regulatory			**1,336.10**			**1,336.10**	**0.00**	0.00%	**3.56%**	**3.56%**
Debt Retirement Charge (DRC)	200,000.00	0.00700	1,400.00	200,000.00	0.0070	1,400.00	0.00	0.00%	**3.73%**	**3.73%**
Total Bill on RPP (before taxes)			32,491.69			33,173.10	681.41	2.10%	88.50%	
HST		13%	4,223.92		13%	4,312.50	88.58	2.10%	11.50%	
Total Bill (including HST)			36,715.61			37,485.60	769.99	2.10%	100.00%	
Ontario Clean Energy Benefit (OCEB)			0.00			0.00	0.00	#DIV/0!	0.00%	
Total Bill on RPP (including OCEB)			**36,715.61**			**37,485.60**	**769.99**	2.10%	**100.00%**	
Total Bill on TOU (before taxes)			32,491.69			33,173.10	681.41	2.10%		88.50%
HST		13%	4,223.92		13%	4,312.50	88.58	2.10%		11.50%
Total Bill (including HST)			36,715.61			37,485.60	769.99	2.10%		100.00%
Ontario Clean Energy Benefit (OCEB)			0.00			0.00	0.00	#DIV/0!		0.00%
Total Bill on TOU (including OCEB)			**36,715.61**			**37,485.60**	**769.99**	2.10%		**100.00%**