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November 15, 2013

Delivered By Courier and RESS

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

Attention: Kirsten Walli
Board Secretary

Re: Haldimand County Hydro Inc. (EB-2013-0134)
2014 Cost of Service Electricity Distribution Rate Application

Dear Ms. Walli:

Haldimand County Hydro Inc. hereby submits its Cost of Service Rate Application, based on a 2014 forward test year, for Electricity Distribution Rates to be effective May 1, 2014 (the "Application").

This Application is filed in accordance with the Ontario Energy Board's (the "Board's") "*Filing Requirements for Transmission and Distribution Applications*", in particular Chapter 2 issued July 17, 2013 and Chapter 5 issued March 28, 2013.

Two hard copies of the Application are now enclosed. An electronic copy of the entire Application in PDF format and required models in Excel format will be submitted through the Board's *Regulatory Electronic Submission System* ("RESS").

This Application is respectfully submitted for the Board's consideration.

Yours truly,
HALDIMAND COUNTY HYDRO INC.

Original signed by

Jacqueline A. Scott
Finance Manager

IN THE MATTER OF the Ontario Energy Board Act, 1998, being Schedule B to the Energy Competition Act, 1998, S.O. 1998, c.15;

AND IN THE MATTER OF an Application by Haldimand County Hydro Inc. to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2014.

Title of Proceeding:	An Application by Haldimand County Hydro Inc. for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2014.
Applicant's Name:	Haldimand County Hydro Inc.
Applicant's Address for Service:	1 Greendale Drive Caledonia, Ontario N3W 2J3
	Attention: R. Jane Albert, President & CEO
	Telephone: 905-765-5344 Fax: 905-765-5316 E-mail: jalbert@hchydro.ca

Applicant's Counsel:	Borden Ladner Gervais LLP Scotia Plaza, 40 King Street West Toronto, Ontario M5H 3Y4 Telephone: 416-367-6000 Fax: 416-361-6749
Applicant's Consultant:	Borden Ladner Gervais LLP Scotia Plaza, 40 King Street West Toronto, Ontario M5H 3Y4 Bruce Bacon, Senior Utility Rate Consultant Telephone: 416-367-6087 Fax: 416-361-7366 E-mail: bbacon@blgcanada.com

Certification of Evidence:

As President & CEO of Haldimand County Hydro Inc., I certify that, to the best of my knowledge, the evidence filed in this Application is accurate and that it is consistent with the Ontario Energy Board's Filing Requirements for Electricity Distribution Rate Applications, including Chapter 2 Cost of Service issued on July 17, 2013 and Chapter 5 Consolidated Distribution System Plan Filing Requirements issued on March 28, 2013.

Original signed by

R. Jane Albert
President & CEO

DATED at Caledonia, ON, this 15th day of November 2013.

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EXECUTIVE SUMMARY

The Applicant is Haldimand County Hydro Inc. (referred to in this Application as the "Applicant" or "HCHI"). The Applicant is a corporation incorporated pursuant to the Ontario *Business Corporations Act* with its head office in the Town of Caledonia, ON. The Applicant carries on the business of distributing electricity within Haldimand County.

The Applicant hereby applies to the Ontario Energy Board (the "Board") pursuant to Section 78 of the *Ontario Energy Board Act, 1998 (*the "OEB Act"*)* for approval of its proposed distribution rates and other charges, effective May 1, 2014. A list of requested approvals is set out in Exhibit 1, Tab 5, Schedule 2.

Except where specifically identified in the Application, the Applicant followed the Board's "*Filing Requirements for Electricity Distribution Rate Applications"*, revised July 17, 2013 (the "Filing Requirements") in order to prepare this Application.

OVERALL BUSINESS STRATEGY

As a result of this Application, HCHI is seeking a decrease in delivery charges for its 18,772 Residential customers of 2.6% and for its 2,363 General Service Less Than 50 kW customers of 10.8% as compared to its current Board Approved distribution rates effective May 1, 2013. The rate reduction follows HCHI's 2006 Vision Statement *"To become recognized as a leading participant in the electricity distribution and related businesses sector in Ontario known particularly for high quality service, resilience and adaptability and continuous improvement and efficiency."*

HCHI is a local distribution company ("LDC") serving over 21,300 customers stretching across an area of 1,252 square kilometers with approximately 1,739 circuit kilometres of overhead distribution line (includes 87 kilometres of line owned by Hydro One Networks Inc. ("HONI") and 96 circuit kilometres of underground distribution lines. Over 97% of HCHI's service territory is represented by rural communities.

HCHI distributes electrical power within the municipal boundary of Haldimand County. Power is supplied from three HONI-owned transformers stations and distributed to the end customers via seven distribution stations. Five of the seven distribution stations are owned by HCHI and two are owned by HONI. The primary supply of power is 4.8/8 kV and 8.32/27.6 kV which is stepped down through approximately 7,259 HCHI-owned transformers. The majority (99.67%) of HCHI's 21,367 customers have a smart meter for the purpose of measuring consumption for electricity for billing purposes, and for providing customers with hourly consumption to assist in understanding their usage, furthering their electricity literacy and encouraging conservation and demand management.

Under the Board's Renewed Regulatory Framework, HCHI understands that it will be expected to demonstrate continuous improvement with a balanced approach to its customers' needs, operational effectiveness, delivery of public policy and financial performance – all as measured against expected performance outcomes.

HCHI's frontline staff responds to an average of 36,400 customer calls per year. Each call is considered an opportunity to assist with, and impart knowledge on, utilizing HCHI's distribution services, understanding regulated and provincial policy changes and explaining the wise and wider use of electricity delivered to the customer's home and/or business.

To assist in providing customers with expanded sources of information, HCHI has enhanced its information channel with web-based services, including a revised and more accessible website, mobile app and social media. HCHI understands that its unique customer base, including both rural and urban customers, benefits from a diverse communication strategy. In particular, HCHI's attention is focused on creating community participation in conservation, safety and power restoration events, regulatory changes and background with general business strategies through the its customer billing inserts including "*The Wire"* and *"Powered Up".*

In 2006 HCHI established its Mission Statement "*To provide efficient, reliable and safe electricity distribution and other related services to customers and to contribute to the development of our jurisdiction's economy and our employees and the protection of the environment while enhancing the value of Haldimand County Utilities Inc*." This Mission Statement is the current sounding board when HCHI is challenged with options on paths to pursue.

The sheer physical size of HCHI's service territory, fourth in the province, significantly contributes to the long-term decision making and goal setting for balancing capital expenditures and maintenance costs with respect to its distribution system infrastructure. HCHI's service territory has been extremely active in renewable generation projects as Haldimand County has attracted four large transmission connected wind and solar projects, either in design or in construction, totalling 583 MW as well as 215 distribution-connected projects totalling 33.9 MW. The proximity to the shores of Lake Erie and available land creates ideal conditions for renewable generation projects.

In the past thirteen years since incorporation, significant work has taken place to tackle and rebuild the aging infrastructure acquired as part of the former Ontario Hydro asset annexations in 1999, including, but not limited to the significant conversions to 27.6 kV distribution circuit lines with the long-term goal of eliminating all distribution substations. Since 2008, HCHI has eliminated three distribution substations. With 63% of the overhead distribution line circuits that still remain at 8 kV or less, HCHI has a large time and financial commitment ahead of it.

During 2012, HCHI experienced one of its best system reliability year's with respect to a reduction in total number of customer interruptions and duration of interruptions. HCHI attributes its expanded efforts in its capital and maintenance programs as a direct contributor to these reductions in interruptions. As part of its last rate rebasing cost of service application in 2010, HCHI developed solid asset management, maintenance

and inspection programs designed to deliver improved reliability and service to its customers.

HCHI has developed a consolidated Distribution System Plan ("DSP") submitted as part of this Application. HCHI's DSP outlines a balanced distribution infrastructure strategy, building on the formalized programs developed in 2010, to continue towards a goal of improved reliability, reduced loss factor, employee and public safety, and recognizing the future with renewable energy generation investments.

HCHI has implemented Minister of Energy Directives regarding the installation of smart meters and conservation and demand management ("CDM") targets – all as a condition of its Distribution Licence. HCHI staff take personal pride in working with their customers to properly introduce electricity distribution-related government and regulatory policy and to help find ways to engage their participation and improve HCHI's service offering. HCHI looks forward to developing enhanced programs that will provide customers with further "behind the meter" solutions to better understand and use the electricity it delivers.

With respect to its CDM targets for programs to be delivered in 2011 through 2014, as at the end of 2012, HCHI has met 69.3% of its 13.3 GWH energy target and 20% of its 2.85 MW demand target. With only a year left to achieve the mandated targets, HCHI's efforts are focused on peak demand reducing programs across all customer segments.

HCHI's financial strategy requires a balance between its distribution system infrastructure, general and administrative assets, operating, maintenance and administrative ("OM&A") expenses, including its staff and operating systems in order to deliver expected service levels for the best possible value. As part of its Application, HCHI has continued to develop this financial strategy, positioning itself for the challenges and opportunities that lie ahead.

As part of the "*Draft Report of the Board on Empirical Research to Support Incentive Rate-setting for Ontario's Electricity Distributors*" (EB-2010-0379) issued September 6, 2013, the Pacific Economics Group Research, LLC ("PEG") provided estimated industry total factor productivity trend and econometric cost benchmarking. The results presented by PEG noted HCHI in the first stretch factor tranche. This tranche is determined when a distributor's actual costs are between 15% and 20% below costs predicted by PEG's cost model. HCHI recognizes that the Board is still finalizing this work and that changes may occur in its final report on this matter.

PROPOSED REVENUE REQUIREMENT

HCHI has requested a Service Revenue Requirement for the 2014 Test Year in the amount of $14,012,613. This represents an increase of $276,722 or 2% over the 2010 Board Approved amount of $13,735,891. Table 1 provides a comparison of the proposed 2014 Test Year Revenue Requirement versus the 2010 Board Approved.

Table 1
Comparison of 2014 Test Year Revenue Requirement to 2010 Board Approved

	2010 Board Approved	2014 Test Year	Change Increase /(Decrease)
OM&A Expenses	$ 7,445,359	$ 8,706,492	$ 1,261,133
Depreciation Expenses	2,817,053	2,113,988	(703,065)
Total Distribution Expenses	$ 10,262,412	$ 10,820,480	$ 558,068
Regulated Return On Capital	$ 2,773,080	$ 3,091,641	$ 318,561
PILs	700,399	100,492	(599,907)
Service Revenue Requirement	**$ 13,735,891**	**$ 14,012,613**	**$ 276,722**
Less: Revenue Offsets	(1,089,144)	(1,138,061)	(48,917)
Base Revenue Requirement	**$ 12,646,747**	**$ 12,874,552**	**$ 227,805**

Based on the 2014 load forecast and customer growth proposed for the 2014 Test Year, as provided for in this Application, HCHI has estimated a gross revenue deficiency of $27,264 based on its current 2013 Board Approved distribution rates. The overview of this revenue deficiency is shown in Exhibit 6, Tab 1, Schedule 1.

The main drivers of this increase in Revenue Requirement and revenue deficiency, as outlined in Exhibit 6, Tab 1, Schedule 2, are as follows:

1. 4.8% compound annual growth rate in OM&A expenses (refer to Exhibit 4, Tab 1, Schedule 2);

2. Addition of Smart Meter costs as a result of HCHI's approved disposition in its Smart Meter Cost Recovery Application (EB-2012-0272);

3. Depreciation expense decrease related to the property, plant, and equipment ("PPE") adjustment on account of the change in estimated useful lives (refer to Exhibit 4, Tab 3, Schedule 3);

4. Incremental return on rate base as a result of the increase of $13,582,391 in rate base (refer to Exhibit 2, Tab 1, Schedule 2) offset by the decrease in the regulated rate of return from 6.90% in the 2010 Board Approved to 5.75% in the 2014 Test Year; and

5. Reduction to forecast Payment in Lieu of Taxes ("PILs") due to adjustments to taxable income as a result of the differences in depreciation recorded for accounting purposes and allowable Capital Cost Allowance ("CCA") for tax purposes (refer to Exhibit 4, Tab 4, Schedule 1).

BUDGETING DIRECTIVES AND ASSUMPTIONS

HCHI compiles budget information in three major components for its annual budget process, including: (i) revenue; (ii) OM&A expenses; and (iii) capital expenditures. Budget information was prepared for both the 2013 Bridge Year and the 2014 Test Year.

HCHI's budgets are prepared annually by Management and reviewed and approved by HCHI's Board of Directors.

Revenue Forecast:

HCHI's 2014 Test Year distribution revenue was forecast using the load forecast model detailed in Exhibit 3, Tab 2, Schedules 1 and 2 for all customer rate classes except the Embedded Distributor – Hydro One Networks Inc. ("HONI"). HONI supplied HCHI with an existing weather normalized load forecast that has been previously used by HONI for their own purposes. The total forecasted load for the 2014 Test Year was multiplied by the proposed 2014 distribution rates to arrive at the 2014 Test Year distribution revenue.

The load forecast is developed by considering monthly historical purchased load from January 2003 to December 2012 inclusive, subject to a multifactor regression analysis to "predict" annual purchased consumption for 2013 and 2014. Variables incorporated into the regression analysis on a monthly basis, include: (i) heating and cooling degree days; (ii) spring and fall flag (to denote peak demand); (iii) number of days in month; (iv) CDM activity; (v) summer months flag; and (vi) employment trends in the Hamilton/Niagara Peninsula provided by Statistics Canada. The weather normalized purchases are then converted to a billed kWh by customer rate class.

Based on the load forecast methodology noted above (inclusive of HONI), the 2014 Test Year's kWh forecast is 420,503,464 kWh or a 2.25% decrease over the 2010 Board Approved kWh forecast of 430,184,875 kWh.

The load forecast model also forecasts the number of customers, usage by customer class and demand for those classes where demand is the billing determinant. The forecast of customers is determined using a geomean analysis. The forecast number of customers/connections for the 2014 Test Year is 24,845 or a 1.02% increase over the 2010 Board Approved customers/connections of 24,594.

Operating, Maintenance and Administrative ("OM&A") Expense Forecast:

The OM&A forecasts for the 2013 Bridge Year and the 2014 Test Year have been based on an in-depth review of business requirements using a zero-based budgeting approach. The process requires each department to review costs, including internal labour, material and third party contracts in conjunction with corporate objectives and future labour requirements.

As part of the OM&A expense forecast process, key assumptions were made since timing prevented the use of actual forecast numbers.

- HCHI's collective bargaining agreement was settled with the International Brotherhood of Electrical Workers ("IBEW") on May 31, 2013. The settlement period is for a four year term, effective April 1, 2013 until March 31, 2017. Settlement was reached with an annual wage increase in the order of 2.5%.

- Management and non-unionized staff salaries have been adjusted at the same rates and effective dates as those contained in the contract for unionized staff. Further information is outlined in Exhibit 4, Tab 2, Schedule 4.

- The allocation of OM&A costs such as labour, trucks and indirect costs are based on estimates of planned and unplanned activities. Unplanned maintenance estimates are determined using trending from prior years' experience and known changes in work practices.

- Third party costs are reviewed on a regular basis to determine cost effectiveness and these costs are reviewed at the time of contract renewal and reviewed again during the budgeting process.

Capital Budget:

HCHI has provided a detailed consolidated Distribution System Plan ("DSP") in accordance with the Board's "*Chapter 5 Consolidated Distribution System Plan Filing Requirements"* ("DP Filing Requirements") dated March 28, 2013. HCHI's DSP is contained as Appendix A to Exhibit 2.

LOAD FORECAST SUMMARY

HCHI has submitted in its Application a load forecast methodology that uses multifactor regression analysis in accordance with the Filing Requirements. This is a similar model to that used in HCHI's 2010 Cost of Service ("COS") rate application and by a number of other distributors in previous COS rate applications that have been approved by the Board.

HCHI's weather normalized load forecast was developed using a total system weather normalized purchased energy forecast based on a multifactor regression that incorporates monthly historical purchased load, heating and cooling degree days, days in the month, spring/fall flag, summer months flag, historical Conservation and Demand Management ("CDM") savings, and monthly full-time employment for the Hamilton-Niagara Peninsula Region, which are all discussed in further detail in this Exhibit 3, Tab 2, Schedule 2. The resultant level of weather normalized purchases for the 2013 Bridge Year and the 2014 Test Year are then adjusted by a 5-year (2008 to 2012) historical average loss factor to produce a weather normalized billed energy (kWh) forecast.

The billed energy by customer class is developed based on a forecast of customer numbers and historical usage patterns per customer. For customer classes that have weather sensitive load, the forecasted billed energy is adjusted to ensure that the total billed energy forecast by customer class is equivalent to the total weather normalized billed energy forecast that has been determined from the regression model. A further adjustment for forecasted CDM savings in the 2013 Bridge Year and the 2014 Test Year is completed to derive consumption by customer rate class.

The forecast of customers by rate class is determined using a geometric mean analysis of historical data. The 2013 Bridge Year customer forecast was not adjusted by the geometric analysis; it is the actual customer/connection numbers for each of the customer rate classes as at July 31, 2013. The 2014 Test Year customer forecast was

then determined using the geometric analysis applied to the 2013 Bridge Year customer numbers.

For those customer rate classes that use kW for the distribution volumetric billing determinant, an adjustment factor is applied to class energy (kWh) forecast based on the historical relationship between kW and kWh.

HCHI's weather normalized load forecast has been used for all its customer rate classes excluding the Embedded Distributor - HONI rate class. HONI supplied HCHI with an existing weather normalized load forecast that has been previously used by HONI for their own purposes, including kWh and kW for all embedded points for the 2013 Bridge Year and the 2014 Test Year.

Based on HCHI's load forecast methodology, the 2014 Test Year total load forecast, including HONI, is 420,503,464 kWh or a 2.25% decrease over the 2010 Board Approved kWh forecast of 430,184,875 kWh. Table 2 summarizes the load forecast by customer rate class for the 2014 Test Year as compared to the 2010 Board Approved.

Table 2
Summary of Load Forecast kWh Growth

Customer Class	2010 Board Approved kWh	2014 Test Year kWh	kWh Change	% Change
Residential	171,936,412	169,003,519	(2,932,893)	(1.71%)
General Service Less Than 50 kW	61,801,919	53,925,141	(7,876,778)	(12.75%)
General Service 50 to 4,999 kW	110,031,720	121,879,907	11,848,187	10.77%
Street Lighting	2,328,757	2,387,575	58,818	2.53%
Sentinel Lighting	418,928	327,143	(91,785)	(21.91%)
Unmetered Scattered Load	482,264	350,238	(132,026)	(27.38%)
Total Excluding Embedded Distributor	**347,000,000**	**347,873,523**	**873,523**	**0.25%**
Embedded Distributor - Hydro One Networks Inc.	83,184,875	72,629,941	(10,554,934)	(12.69%)
Total Load Forecast	**430,184,875**	**420,503,464**	**(9,681,411)**	**(2.25%)**

Based on the geometric mean analysis, the expected number of customers/connections for the 2014 Test Year is 24,845 or a 1.02% increase over the 2010 Board Approved customers/connections of 24,594. Table 3 summarizes the customers/connections by customer class for the 2014 Test Year as compared to the 2010 Board Approved.

Table 3
Summary of Customer Growth

Customer Class	2010 Board Approved Customer/ Connection	2014 Test Year Customer/ Connection	Customer/ Connection Change	% Change
Residential	18,534	18,772	238	1.28%
General Service Less Than 50 kW	2,357	2,363	6	0.25%
General Service 50 to 4,999 kW	143	153	10	6.99%
Street Lighting	2,879	2,979	100	3.47%
Sentinel Lighting	589	502	(87)	(14.77%)
Unmetered Scattered Load	84	68	(16)	(19.05%)
Total Excluding Embedded Distributor	**24,586**	**24,837**	**251**	**1.02%**
Embedded Distributor - Hydro One Networks Inc.	8	8	-	0.00%
Total Load Forecast	**24,594**	**24,845**	**251**	**1.02%**

RATE BASE AND CAPITAL PLANNING

HCHI has calculated its 2014 Test Year rate base as $53,797,605, an increase of $13,582,392 or 34% over the 2010 Board Approved rate base of $40,215,213. This increase in rate base is attributable to an increase of $11,987,631 in the average net book value of capital assets and an increase of $1,594,761 in the working capital allowance. Table 4 provides a summary of the rate base from the 2010 Board Approved through to the 2014 Test Year inclusive.

Table 4
Summary of Rate Base

Description	2010 Board Approved	2010 Actual Year	2011 Actual Year	2012 Actual Year	2013 Bridge Year	2014 Test Year
Gross Capital Assets	58,164,822	57,445,569	62,226,258	71,205,185	75,039,623	81,018,541
Accumulated Depreciation	23,220,128	22,697,861	25,539,681	29,310,689	30,285,402	32,403,359
Net Book Value	34,944,694	34,747,708	36,686,577	41,894,496	44,754,221	48,615,182
Average Net Book Value	**34,697,070**	34,537,344	35,717,143	39,290,537	43,324,358	**46,684,701**
Working Capital	36,787,618	44,313,984	47,739,197	48,317,165	53,332,548	54,714,649
Working Capital Allowance %	15%	15%	15%	15%	15%	13%
Working Capital Allowance	**5,518,143**	6,647,098	7,160,880	7,247,575	7,999,882	**7,112,904**
Rate Base	**40,215,213**	**41,184,442**	**42,878,023**	**46,538,112**	**51,324,240**	**53,797,605**

HCHI's 2014 Test Year gross capital assets have increased by $22,853,719 or 39% from the 2010 Board Approved. This represents an average annual capital spend (net of contributed capital) of $5,500,000 for the 2011 Actual, 2012 Actual (excluding the Smart Meter disposition), 2013 Bridge Year, and 2014 Test Year.

HCHI's required annual capital expenditures are $5,501,010 for the 2013 Bridge Year and $5,978,918 for the 2014 Test Year. This compares to historical spends of $3,256,765 in 2010 Actual, $4,927,694 in 2011 Actual, and $5,359,947 in 2012 Actual, excluding Smart Meters. The 2010 Board Approved capital expenditures were $3,312,301. All capital expenditure amounts are net of contributed capital in the year. Details of HCHI's capital expenditures and Fixed Asset Continuity Schedules can be found in Exhibit 2, Tab 2 and Tab 5.

As mentioned in Tab 1, Schedule 3 of this Exhibit, HCHI has developed a DSP in accordance with the DP Filing Requirements. HCHI's DSP incorporates matters pertaining to its Distribution Asset Management Plan ("DAMP"), its Renewable Energy Generation Investment Plan ("REG Plan"), and regional infrastructure planning. The DSP is filed as Appendix A in Exhibit 2.

HCHI's DSP builds on the DAMP that formed part of HCHI's 2010 COS rate application (EB-2009-0265) and will continue to evolve over time. HCHI's main objective in managing its distribution assets is to optimize performance of the assets at a reasonable cost with due regard for system reliability, public and employee safety and customer service requirements. HCHI considers performance-related asset information including, but not limited to, data on reliability, asset age and condition, loading, customer connection requirements, and system configuration, to determine investment needs of the system.

HCHI has been, and continues to be, focused on maintaining the adequacy, reliability, and quality of service to its distribution customers through effective capital spending.

The DSP presents HCHI's approach to asset management and capital expenditure planning for a 10 year period (five historical years plus five forecast years). HCHI has categorized the capital expenditures over the 10 year period according to the following four investment categories in accordance with the DP Filing Requirements:

- System Access
- System Renewal
- System Service
- General Plant

The DSP includes a number of multi-year system renewal and system service investments, such as:

1. Lake Erie Shoreline upgrades – this area runs along approximately 60 kilometres of the north shores of Lake Erie. Customers are supplied by a distribution system that is at end of life, connected to 4.8/8 kV, which is difficult to access due to its location off of municipal roadways, and heavily treed;

2. Underground XLPE Cable replacements – the 2013 Asset Condition Assessment identified a significant quantity of underground cable (non-duct) that are "flagged for action" in the next 5 years;

3. 4.8/8.32 kV Distribution system – a large part of the distribution system (63%) is connected to a Distribution Station ("DS") or Step Down Transformer ("SD") with a voltage of 4.8/8.32 kV. The DSP and REG Plan both discuss the capacity limitations that the 8 kV system has for both load customer connections and generation customer connections; and

4. Municipal project partnerships – the municipality (i.e. Haldimand County) has completed and has planned a number of road reconstruction projects to rebuild urban municipal infrastructure. HCHI has and will continue to partner in these projects where feasible to install underground duct while the road right-of-way is under construction as part of a conversion or a conversion project in the future.

The DSP summarizes renewable generation investments that are described in more detail in the REG Plan. Investments for the five forecast years are summarized in the Table 5 below.

Table 5
REG Capital Investments – 2014 to 2018

HCHI Generator Connection Capital Projects 2014 – 2018						
Capital Cost for Renewables	**2014**	**2015**	**2016**	**2017**	**2018**	**Total**
REG Enabling Improvement Investments						
SCADA System	$246,000					$246,000
REG Expansion Investments						
Dunnville TS - New Feeder Egress & Metering		$260,000				$260,000
LDC Generator Cost Cap	$900,000	$900,000	$900,000	$900,000	$900,000	$4,500,000
Dunnville TS Breaker Position	$377,383					$377,383
Total REG Capital Investments	$1,523,383	$1,160,000	$900,000	$900,000	$900,000	$5,383,383

The REG expenditures for each year are described as follows:

1. 2014 Test Year:
    a. SCADA system investments;
    b. $900,000 for LDC obligation under the Distribution System Code for renewable energy expansion cost cap ($90,000 per MW); and
    c. Additional breaker position at Dunnville TS (REG expansion portion).
2. 2015 Forecast Year:
    a. $900,000 for LDC obligation under the Distribution System Code for renewable energy expansion cost cap ($90,000 per MW); and
    b. Dunnville TS feeder egress and make ready work (related to additional breaker position in 2014 Test Year).
3. 2016 – 2018 Forecast Years:
    a. $900,000 for LDC obligation under the Distribution System Code for renewable energy expansion cost cap ($90,000 per MW).

Per the Filing Requirements and section 79.1 of the OEB Act and Regulation 330/09 under the OEB Act, HCHI has allocated the costs of the eligible investments for the connection of qualifying generation facilities, as noted above, between its ratepayers (i.e. direct benefit portion) and all Ontario ratepayers (i.e. provincial recovery portion). HCHI has assumed the direct benefit percentages to be 17% for REG expansion

investments and 6% for REG enabling improvement investments. Table 6 details the amount HCHI is seeking to recover from the Ontario ratepayers.

Table 6
REG Capital Investments – Provincial Recovery

REG Enabling Improvement Investments	2014	2015	2016	2017	2018	Total
Provincial Recovery Portion (94%)						
SCADA System	231,240					231,240
	231,240					**231,240**
REG Expansion Investments	**2014**	**2015**	**2016**	**2017**	**2018**	**Total**
Provincial Recovery Portion (83%)						
Cost Cap - 250 kW Renewable Generator						-
Dunnville TS Breaker Position	313,325					313,325
Cost Cap - Renewable Generator	747,000	747,000	747,000	747,000	747,000	3,735,000
Dunnville TS - Feeder Egress / Metering		215,800				215,800
	1,060,325	**962,800**	**747,000**	**747,000**	**747,000**	**4,264,125**
Total Provincial Recovery Portion	**1,291,565**	**962,800**	**747,000**	**747,000**	**747,000**	**4,495,365**

Capital expenditures in the five forecast years, 2014 to 2018, total $27,534,000 across the four investment categories. The following Table 7 summarizes the expenditures across the Board's four investment categories.

Table 7
5-Year Forecast (2014 to 2018) of Capital Expenditures

Investment Category	5-Year Capital Expenditures
	($'000)
System Access	$ 7,535
System Renewal	5,400
System Service	11,831
General Plant	2,768
Total	**$ 27,534**

The DSP details the 2014 Test Year capital expenditures summarized in the OEB Appendix 2-AA "Capital Projects" and below:

System Access Expenditures: $1,978,000

- Betterments, line extensions, services and meters to accommodate the connection of new customers;
- Renewable energy generation cost cap (LDC portion as per Distribution System Code); and
- LDC portion of new breaker position and make ready work at Dunnville Transformer Station.

System Renewal Expenditures: $375,000

- End of life pole replacements.

System Service Expenditures: $2,946,000

- 4 projects that convert areas from 8 kV to 27.6 kV; and
- 2 municipal partnership projects in urban areas to install underground duct and infrastructure.

General Plant Expenditures: $680,000

- Investments in fleet replacement;
- Investments in tools, shop and measuring equipment for day to day operations;
- Investments in information technology hardware and software to maintain and enhance information system technology for security purposes, mitigating risks for disaster recovery and for day to day use to maintain business and operations; and
- Investments in data integration to optimize systems for improved operating efficiencies and improved planning.

OVERVIEW OF OPERATING, MAINTENANCE AND ADMINISTRATIVE ("OM&A") EXPENSES

For the 2014 Test Year, HCHI is proposing recovery through distribution rates of $8,706,492 in Operating, Maintenance, and Administrative ("OM&A") costs. This is an increase of $1,261,133 or 17% over the 2010 Board Approved OM&A costs of $7,445,359. Table 8 summarizes the year over year OM&A costs increases also detailed in Exhibit 4, Tab 1 and Tab 2.

Table 8
Summary of OM&A Costs

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Operating	$ 1,418,231	$ 1,454,866	$ 1,669,077	$ 2,061,484	$ 1,901,712	$ 1,926,274
Maintenance	$ 2,693,492	$ 2,187,634	$ 2,459,521	$ 2,311,614	$ 2,802,176	$ 2,751,043
Billing and Collecting	$ 1,319,423	$ 1,305,988	$ 1,154,952	$ 1,867,865	$ 1,565,594	$ 1,618,934
Community Relations	$ 46,836	$ 42,643	$ 45,426	$ 143,208	$ 64,620	$ 69,320
Administrative and General	$ 1,967,377	$ 1,883,392	$ 2,029,380	$ 2,037,455	$ 2,379,386	$ 2,340,921
Total	**$ 7,445,359**	**$ 6,874,523**	**$ 7,358,356**	**$ 8,421,626**	**$ 8,713,488**	**$ 8,706,492**
%Change (year over year)			7.0%	14.4%	3.5%	(0.1%)

The proposed 2014 Test Year OM&A costs summarized in Table 8 above and detailed in Exhibit 4 represent HCHI's integrated set of asset maintenance and customer activity needs designed to: (i) meet public and employee safety objectives; (ii) to comply with the Distribution System Code, environmental requirements and government direction; (iii) maintain electricity distribution business service quality and reliability at targeted performance levels; and (iv) provide services to customers connected to HCHI's distribution system. These costs were developed through a detailed budgeting and planning process and based on reviews of historical costs and also reasoned analysis of trends that are impacting the industry.

There has been considerable change in the electricity distribution sector since HCHI's last rebasing in 2010 including: (i) the implementation of Smart Meters; (ii) Time of Use ("TOU") pricing; (iii) mandated Conservation and Demand Management ("CDM")

programs; (iv) requirements under the Green Energy Act ("GEA") Plan with respect to renewable generation; and (v) the implementation of revised depreciation and capitalization policies for regulatory accounting purposes. These government mandated requirements, which fall under "Public Policy Responsiveness" as part of the Board's Renewed Regulatory Framework for Electricity Distributors ("RRFE"), have translated into incremental OM&A costs for HCHI since its last rebasing.

In addition to increases in OM&A costs as a result of government mandated requirements, HCHI has experienced increases in OM&A costs attributable to: (i) salaries and wages which have increased by approximately 3% per year; (ii) increases in the employee complement to support the government mandated requirements, regulatory compliance, and capacity constraints in certain key departments; (iii) increased benefit costs for the current and forecast employee complement, and in particular significant increases in OMERs pension costs; and (iv) increases in information technology costs.

HCHI's total compensation, including salaries, wages and benefits in the amount of $4,658,109 for the 2014 Test Year have increased by $955,019 or 26% over the 2010 Board Approved amount of $3,703,090. As discussed in the paragraph above, these increases are related to the salary and wage increases of approximately 3% per year, increase of six employees, and the significant increase in benefit costs, particularly with respect to OMERs contributions.

STATEMENT OF CAPITAL COST PARAMETERS

HCHI is requesting the deemed capital structure as provided for in the *"Report of the Board on the Cost of Capital for Ontario's Regulated Utilities"* (EB-2009-0084) issued December 11, 2009, comprised of 60% debt – 56% long-term and 4% short-term - and 40% equity. This is the same deemed capital structure approved in HCHI's 2010 COS rate application.

For the 2014 Test Year, HCHI's deemed debt is $1,159,231 and deemed equity is $1,932,410. HCHI is requesting a weighted average debt rate of 3.59% on total debt. The weighted average debt rate of 3.70% on the long-term debt is based on HCHI's actual long-term debt rates. HCHI has used a return on short-term debt of 2.07%, consistent with the *Cost of Capital Parameter Updates for 2013 Cost of Service Applications* issued by the Board on February 14, 2013. HCHI understands that the Board will be finalizing the return on short-term debt in early 2014 for rates effective May 1, 2014. HCHI's use of a return on short-term debt of 2.07% as a proxy in this Application is without prejudice to any revisions that may be adopted by the Board in early 2014.

HCHI is requesting a return on equity ("ROE") of 8.98% consistent with the *Cost of Capital Parameter Updates for 2013 Cost of Service Applications* issued by the Board on February 14, 2013. HCHI understands that the Board will update the return on equity rate in early 2014 for rates effective May 1, 2014. HCHI's use of a ROE of 8.98% as a proxy in this Application is without prejudice to any revised ROE that may be adopted by the Board in early 2014.

Table 9 summarizes the proposed deemed capital structure and cost of capital. Further details can be found in Exhibit 5 to this Application.

Table 9
2014 Test Year Capital Structure and Cost of Capital

	Capitalization Ratio		Cost Rate	Return
	(%)	($)	(%)	($)
Debt				
Long-term Debt	56.00%	$30,126,659	3.70%	$1,114,686
Short-term Debt	4.00%	$2,151,904	2.07%	$44,544
Total Debt	60.0%	$32,278,563	3.59%	$1,159,231
Equity				
Common Equity	40.00%	$21,519,042	8.98%	$1,932,410
Preferred Shares		$ -		$ -
Total Equity	40.0%	$21,519,042	8.98%	$1,932,410
Total	100.0%	$53,797,605	5.75%	$3,091,641

OVERVIEW OF COST ALLOCATION AND RATE DESIGN

Cost Allocation

HCHI has prepared and is filing a cost allocation study consistent with the Board's "*Cost Allocation Information Filing Guidelines for Electricity Distributors"* issued November 15, 2006 and subsequently updated on March 31, 2011 in the "*Report of the Board: Review of Electricity Distribution Cost Allocation Policy"* (EB-2010-0219). HCHI's cost allocation study is based on the Board's revised Cost Allocation Model issued on August 2, 2013 to be used by 2014 COS filers.

HCHI's cost allocation study reflects the 2014 Test Year costs and asset information, 2014 load forecast information by customer rate class, 2014 forecast customer and meter information, and the 2014 demand values based on the weather normalized load forecast used to design rates. HCHI has developed its own weighting factors based on discussions with internal staff experienced in the subject area.

The use of HCHI's weighting factors as opposed to the Board's default factors, combined with the allocation of costs related to Smart Meters, has resulted in a change in HCHI's cost allocation by customer rate class in its 2014 cost allocation study.

Table 10 compares the allocated costs by customer rate class from HCHI's 2010 COS rate application to the cost allocation study updated for this Application.

Table 10
Allocated Costs by Customer Class

Customer Class	2010 Allocated Costs	%	2014 Allocated Costs	%
Residential	$ 9,256,358	67.39%	$ 9,745,962	69.55%
General Service Less Than 50 kW	$ 2,195,844	15.99%	$ 1,865,501	13.31%
General Service 50 to 4,999 kW	$ 1,409,865	10.26%	$ 1,431,979	10.22%
Street Lighting	$ 465,608	3.39%	$ 399,236	2.85%
Sentinel Lighting	$ 204,538	1.49%	$ 176,206	1.26%
Unmetered Scattered Load	$ 30,758	0.22%	$ 24,639	0.18%
Embedded Distributor - Hydro One Networks Inc.	$ 172,921	1.26%	$ 369,092	2.63%
Total	$ 13,735,892	100.00%	$ 14,012,615	100.00%

Table 11 details the most recent Board Approved revenue-to-cost ratios from HCHI's 2011 Incentive Rate Mechanism ("IRM3") rate application (EB-2010-0086) to HCHI's proposed revenue-to-cost ratios for the 2014 Test Year. The most recent Board Approved revenue-to-cost ratios reported are from the 2011 IRM3 instead of the 2010 COS rate application as this was the last of the two rate years to move the revenue-to-cost ratios for the Street Lighting and Sentinel Lighting classes to the bottom of the range at 70%.

Table 11
Revenue to Cost Ratios

Customer Class	2011 IRM3 Board Approved	2014 Cost Allocation Study	2014 Proposed Ratios	2015 Proposed Ratios	Board Targets (Min.to Max.)
	%	%	%	%	%
Residential	99.86	96.87	100.00	100.00	85 - 115
General Service Less Than 50 kW	101.78	111.87	100.00	100.00	80 - 120
General Service 50 to 4,999 kW	112.88	128.55	105.90	105.20	80 - 120
Street Lighting	70.00	86.31	86.30	86.30	70 - 120
Sentinel Lighting	70.00	69.27	74.60	80.00	80 - 120
Unmetered Scattered Load	80.81	80.63	80.60	80.60	80 - 120
Embedded Distributor - Hydro One Networks Inc.	100.00	42.10	105.50	105.50	80 - 120

HCHI has not deviated from the Board's 2014 Cost Allocation Model. Further details with respect to HCHI's 2014 cost allocation study can be found in Exhibit 7.

Rate Design

HCHI has calculated its proposed distribution rates by customer rate class for the 2014 Test Year based on the proposed Rate Design model in Exhibit 8. Table 12 sets out HCHI's proposed 2014 electricity distribution rates based on: (i) the allocation of the base revenue requirement across the customer rate classes according to the revenue-to-cost ratios; (ii) the current fixed / variable ratios by customer class; and (iii) the current transformer ownership allowance.

Table 12
Proposed 2014 Electricity Distribution Rates

Customer Class	Unit of Measure		Proposed Volumetric Charge	Proposed Monthly Service Charge
Residential	kWh	Customer	$ 0.0275	$ 18.85
General Service Less Than 50 kW	kWh	Customer	$ 0.0182	$ 25.77
General Service 50 to 4,999 kW	kW	Customer	$ 3.9926	$ 84.98
Street Lighting	kW	Connection	$ 15.6168	$ 6.10
Sentinel Lighting	kW	Connection	$ 36.4943	$ 14.14
Unmetered Scattered Load	kWh	Connection	$ 0.0027	$ 20.87
Embedded Distributor - Hydro One Networks Inc.	kW	Customer	$ 1.4731	$ 478.04
Total				

Based upon the customer bill impacts, as summarized in Tab 1, Schedule 10, Appendix A, HCHI is not proposing rate mitigation.

HCHI is proposing to revise the 2014 Total Loss Factor ("TLF") to 1.0663 for each of its regular customer classes from the current Board Approved TLF of 1.0680; and to revise the 2014 TLF for the Embedded Distributor – HONI. rate class to 1.0288 from the current Board Approved TLF of 1.0305.

OVERVIEW OF DEFERRAL AND VARIANCE ACCOUNTS

On April 1, 2009 Board staff issued its "*Board Staff Discussion Paper on Electricity Distributors' Deferral and Variance Account Review*" for stakeholder comment. On July 31, 2009 the Board issued its "*Report on Electricity Distributors' Deferral and Variance Account Review Initiative*" ("EDDVAR Board Report"), which sets out the Board's policy for the annual review and disposition of deferral and variance accounts in a rebasing year, including filing guidelines.

In accordance with the EDDVAR Board Report, HCHI is requesting the disposition of its Group 1 and Group 2 deferral and variance accounts ("DVAs") including the closing principal and carrying charge balances as of December 31, 2012 and the projected carrying charges from January 1, 2013 to April 30, 2014 calculated on the closing principal balance as of December 31, 2012. The projected interest has been calculated using the Board's prescribed interest rates.

HCHI is seeking disposition of its Group 1 and Group 2 DVAs, the Lost Revenue Adjustment Mechanism variance account ("LRAMVA"), and the PILs and Tax Variance Sub-account OVAT/HST ITC (50%) over a one year period effective with the change in distribution rates effective May 1, 2014. The Group 1 account for the Global Adjustment has been allocated to the non-RPP customers based on consumption.

HCHI is also seeking disposition of the 1576 Account, "Accounting Changes under CGAAP", (including the rate of return calculated on this account), over a five year period effective May 1, 2014. Carrying charges are not applicable to this account.

HCHI accounts for the DVAs separately for each of its regular customer rate classes from the Embedded Distributor – HONI rate class and therefore, has requested separate DVA rate riders in this Application. Details have been provided in Exhibit 9. The following Table 13 summarizes the DVA disposition amounts.

Table 13
Deferral and Variance Accounts Requested For Disposition

		All Rate Classes Excluding Embedded Distributor			Embedded Distributor - Hydro One Networks Inc.			**TOTAL All Rate Classes**		
Deferral and Variance Accounts	Account No.	Principal & Interest as at Dec. 31, 2012	Interest Projected 2013 and 2014	Total Claim	Principal & Interest as at Dec. 31, 2012	Interest Projected 2013 and 2014	Total Claim	**Principal & Interest as at Dec. 31, 2012**	**Interest Projected 2013 and 2014**	**Total Claim**
Group 1 Accounts										
Low Voltage Charges	1550	$ (21,058)	$ (407)	$ (21,465)	$ -	$ -	$ -	**$ (21,058)**	**$ (407)**	**$ (21,465)**
Wholesale Market Service Charge	1580	$ (625,365)	$ (12,175)	$ (637,540)	$ (120,104)	$ (2,336)	$ (122,440)	**$ (745,469)**	**$ (14,511)**	**$ (759,980)**
Retail Transmission Network Charge	1584	$ (111,382)	$ (2,176)	$ (113,558)	$ 139,060	$ 2,703	$ 141,763	**$ 27,678**	**$ 527**	**$ 28,205**
Retail Transmission Connection Charge	1586	$ (94,329)	$ (1,821)	$ (96,150)	$ 90,273	$ 1,756	$ 92,029	**$ (4,056)**	**$ (65)**	**$ (4,121)**
Power	1588	$ (60,479)	$ (1,200)	$ (61,679)	$ (16,791)	$ (323)	$ (17,114)	**$ (77,270)**	**$ (1,523)**	**$ (78,793)**
Global Adjustment	1589	$ 609,609	$ 11,977	$ 621,586	$ (10,402)	$ (187)	$ (10,589)	**$ 599,207**	**$ 11,790**	**$ 610,997**
Disposition and Recovery/Refund of Regulatory Balances	1595	$ (20,995)	$ (15)	$ (21,010)	$ 35,672	$ 540	$ 36,212	**$ 14,677**	**$ 525**	**$ 15,202**
Total Group 1 Accounts		$ (323,998)	$ (5,818)	$ (329,816)	$ 117,708	$ 2,153	$ 119,861	**$ (206,290)**	**$ (3,665)**	**$ (209,955)**
Group 2 Accounts										
Other Regulatory Assets - Incremental Capital Charges	1508	$ 6,168	$ 116	$ 6,285	$ -	$ -	$ -	**$ 6,168**	**$ 116**	**$ 6,285**
Retail Cost Variance Account - Retail	1518	$ 325,151	$ 6,214	$ 331,365	$ -	$ -	$ -	**$ 325,151**	**$ 6,214**	**$ 331,365**
Retail Cost Variance Account - STR	1548	$ 6,118	$ 117	$ 6,235	$ -	$ -	$ -	**$ 6,118**	**$ 117**	**$ 6,235**
Total Group 2 Accounts		$ 337,438	$ 6,447	$ 343,885	$ -	$ -	$ -	**$ 337,438**	**$ 6,447**	**$ 343,885**
Other Accounts										
LRAM Variance Account	1568	$ 82,207	$ 1,611	$ 83,818	$ -	$ -	$ -	**$ 82,207**	**$ 1,611**	**$ 83,818**
Accounting Changes Under CGAAP - Balance plus Return Component	1576	$ (1,878,699)	$ -	$(1,878,699)	$ -	$ -	$ -	**$ (1,878,699)**	**$ -**	**$ (1,878,699)**
PILs and Tax Variance Sub-account - HST/OVAT Input Tax Credits (50%)	1592	$ (152,541)	$ (2,339)	$ (154,880)	$ -	$ -	$ -	**$ (152,541)**	**$ (2,339)**	**$ (154,880)**
Total Other Accounts		$ (1,949,033)	$ (727)	$(1,949,760)	$ -	$ -	$ -	**$ (1,949,033)**	**$ (727)**	**$ (1,949,760)**
Total Deferral & Variance Accounts Request for Disposition		$ (1,935,593)	$ (99)	$(1,935,692)	$ 117,708	$ 2,153	$ 119,861	**$ (1,817,885)**	**$ 2,054**	**$ (1,815,831)**

Also as part of this Application, HCHI is requesting disposition of its Stranded Meters in the amount of $479,441 and proposing a Stranded Meter rate rider for the Residential, General Service Less Than 50 kW, and the General Service 50 to 4,999 kW customer rate classes.

HCHI's REG Plan provides for forecast eligible investments for the period 2014 to 2018 as described in Tab 1, Schedule 5 of this Exhibit, and in Exhibit 2, Exhibit 9, and HCHI's DSP. HCHI has allocated the costs of the eligible investments for the connection of qualifying generation facilities between its ratepayers (i.e. direct benefit portion) and all Ontario ratepayers (i.e. provincial recovery portion). HCHI has assumed the direct benefit percentages to be 17% for REG expansion investments and 6% for REG enabling improvement investments.

HCHI is proposing to record REG capital investments for 2013 through to 2018 inclusive in the deferral account 1531 - "Renewable Connection Capital Deferral Account". The total amount to be recorded to deferral account 1531 is $4,960,165. This represents the proposed provincial recovery portion for the years 2013 to 2018 inclusive and the proposed direct benefit portion for the years 2015 to 2018 inclusive. The direct benefit portion of 2013 and 2014 REG capital investments has been recorded directly to HCHI's regular capital. HCHI is proposing a REG funding adder for the direct benefit portion of these REG Investments to be recovered over a five year period.

Table 14 summarizes all proposed rate riders and the funding adder.

Table 14
2014 Test Year Proposed Rate Riders and Funding Adder

CUSTOMER CLASS	Billing Determinant	Deferral & Variance Rate Rider	Global Adjustment Rate Rider	PP&E Adjustment Rate Rider	Stranded Meter Rate Rider	REG Funding Adder
		(1 year)	(1 year)	(5 year)	(1 year)	(5 year)
Residential	kWh	$ (0.0014)	$ 0.0042	$ (0.0016)	$ 0.0021	$ 0.0002
General Service Less Than 50 kW	kWh	$ (0.0020)	$ 0.0042	$ (0.0010)	$ 0.0019	$ 0.0001
General Service 50 to 4,999 kW	kW	$ (0.9630)	$ 1.4815	$ (0.1257)	$ 0.0571	$ 0.0188
Street Lighting	kW	$ (1.5513)	$ 1.4944	$ (1.4566)		$ 0.2194
Sentinel Lighting	kW	$ 5.9957	$ 1.4975	$ (3.9156)		$ 0.5553
Unmetered Scattered Load	kWh	$ (0.0003)	$ 0.0042	$ (0.0015)		$ 0.0002
Embedded Distributor - Hydro One	kW	$ 0.5729	$ (0.0465)			

OVERVIEW OF BILL IMPACTS

In preparing this Application, HCHI has considered the impacts on its customers, with a goal of minimizing those impacts. Table 15 summarizes the customer bill impacts by customer class, for typical consumption levels based on the proposed distribution rates, load forecast, proposed loss factors, and disposition of deferral and variance accounts provided for in this Application.

Table 15
Summary of Total Monthly Bill Impacts

Rate Class	% Distribution	% Retail Transmission	% Delivery	$ Delivery	% TOTAL BILL
Residential (800 kWh)	(3.3)	0.7	(2.6)	$(1.49)	(1.1)
General Service Less than 50 kW (2,000 kWh)	(13.8)	0.8	(10.8)	$(11.53)	(3.8)
General Service 50 to 4,999 kW (50,000 kWh / 75 kW)	5.6	6.6	5.9	$59.34	1.0
Unmetered Scattered Load (500 kWh)	6.0	0.8	5.0	$1.42	1.9
Sentinel Lighting (1 connection; 77 kWh / 0.21 kW)	16.4	0.8	15.9	$3.21	11.7
Street Lighting (2,973 connections; 170,000 kWh / 550 kW)	3.6	0.8	3.5	$964.17	2.1
Embedded Distributor - Hydro One Networks (6,055,000 kWh / 18,970 kW)	210.0	7.7	39.0	$44,131.37	5.9

Note: Bill Impacts for the following customer classes include the Rate Rider for Global Adjustment - applicable only to non-RPP customers:
- General Service 50 to 4,999 kW
- Street Lighting
- Embedded Distributor - Hydro One Networks

Appendix A provides detailed calculations of the bill impacts provided in Table 15.

CUSTOMER ENGAGEMENT

HCHI actively communicates with its customers regarding ongoing business elements, accomplishments and changes in regulatory matters. Specific communication to HCHI's customers regarding this 2014 COS rate application has been limited to the Haldimand County Utilities Inc. 2012 Annual Report reported at the Annual General Meeting on June 17, 2013 and published on HCHI's corporate website at the end of June 2013 as part of the "*Message from the Chair*".

> *"Every five years, Haldimand County Hydro Inc., is required to file with the OEB a comprehensive Cost of Service Rate Application. The next application is due before the OEB in the Fall of 2013. This process is a major undertaking. Our team has begun to prepare this application and anticipates it being a major focus for the remainder of 2013. In addition to being mandated, this rate setting process provides predictable revenue to our distribution company and allows us to both fulfil our mandate and to provide Haldimand County, our shareholder, with regular income."*

Haldimand County Hydro utilizes several mediums to communicate with its customers:

Corporate Website – A one stop location for HCHI's customers to gain access to important information on the day-to-day aspects of their distribution services, rates, regulatory matters and decisions, customer initiatives, conservation and demand management programs and their participation. HCHI's corporate website also provides customers a mechanism to reach HCHI.

Bill Inserts – including: *The Wire*, a customer newsletter that provides customers with information regarding current customer-specific initiatives; Specific safety messages; and *Powered Up*, a Corporate newsletter update to customers on capital programs, business strategies and community contributions.

Social Media – to establish real time access to our customers to start and remain engaged in a conversation through *Twitter*.

Mobile Applications- primarily to promote an easy access to customers to report outages and provide easy access to time sensitive messages to customers. HCHI's Mobile Application also provides customers a convenient mechanism to reach HCHI anytime anywhere.

Local Press – promote key issues via press releases, radio coverage and news advertisements.

Large Customer Meetings – at least annually, a face to face meeting is offered to customers to review key initiatives such as conservation opportunities, capital plans, standard billing processes and updates on regulatory proceedings underway.

Participation on the Hospital Green Group – HCHI sits on the committee as an active member. An important opportunity to participate and support a "culture of conservation" at the community level.

Individual Customer Meetings – review specific customer plans and needs to better understand long-term requirements for power supply, growth, interest in renewable and non-renewable generation and impact on long term rates. These meetings tend to be focused around our large customers.

HCHI utilizes current customer's feedback and experiences to shape our business direction where practical and with regard to its long-term strategy of improved reliability, service quality and capacity.

Building upon our past efforts to engage our customers, HCHI is commencing a change in strategy to include more in-depth engagement tools, metrics and a feedback loop.

HCHI proactively informs and invites open dialogue with its customers. Annually we invite our large general service customers to meet with us to review opportunities to

explore conservation initiatives and opportunities as well learn more about changes in the industry and our efforts to address the changes. HCHI's customer engagement channels are focused around direct mails, bill inserts, updated website, use of social media and mobile applications. Meeting with its Residential customers in a formal manner has been less frequent. In 2009 and 2010 public sessions were held to introduce Smart Meters and TOU pricing. Attendance at the three sessions averaged 35 persons per session. Ongoing efforts include bill inserts such as "*The Wire*" and "*Powered Up*", which promote local customers in their conservation and demand management initiatives and utilize the same forum to broadcast regulatory changes. HCHI does proactively find ways to connect with its customers through community events.

Along with formal meetings with its large General Service customers, HCHI meets regularly with many of its large users to review outage statistics, capacity, conservation, billing and their future requirements.

HCHI staff received over 172,462 customer phone calls between January 1, 2009 and July 31, 2013. Every call was received via a direct line to our customer which is captured and managed and responded to. Each opportunity to speak with our customer to promote, educate and extend feedback to better enhance business is used. The voice of HCHI's customer has significance in how it builds and refines its business processes and strategies.

In 2013, HCHI conducted a small focus group to determine what they knew about the electricity business and the service it provides in the community. HCHI feels strongly that the voice of tomorrow requires attention if we have any hope in changing culture and outcomes. Here's what they told us:

- 50% of those surveyed know that HCHI distributes electricity (compared to generating electricity or installing wind turbines).

- 68% knew about TOU rates and that it is more expensive to watch TV after school than on the weekend.
- 41% said they have looked at a hydro bill.
- 86% knew about "phantom power" and that some electronic devices still use electricity even when they are just plugged in.

During 2014, HCHI plans further expand both its formal and informal communications with customers and stakeholders to keep the conversation going. Plans include:

1. Continuing with regular meetings with its General Service customers.
2. Personally meeting with its top 25 electricity users to share mutual goals.
3. Exploring working with the Niagara Erie Power Alliance ("NEPA"), a group of local LDCs of which HCHI is a member, on a joint effort to formally survey customers. Generically this could produce more global regional results.
4. Continuing to utilize social media tools including expanding their use to directly engage with meaningful updates. HCHI is very prepared to hear what its customers are saying.
5. Utilizing an email blast newsletter to communicate real time issues with customers segmented by customer type. Proactively keeping them in the loop on HCHI's activities such as outage updates, conservation initiatives, celebrating great moments and conservation community leaders. Conducting focus groups each year across HCHI's customer rate classes.
6. Continuing to work with the future electricity users and leaders to educate them on safety, conservation and the value of electricity in the community and across Ontario.

FINANCIAL INFORMATION

AUDITED FINANCIAL STATEMENTS

HCHI's Audited Financial Statements for each of the year ended December 31, 2010, 2011 and 2012, accompany this Schedule as Appendix B, C, and D, respectively.

RECONCILIATION OF AUDITED FINANCIAL STATEMENTS TO FINANCIAL RESULTS FILED

No reconciliation is required between the Audited Financial Statements filed as Appendix B, C, and D and the financial results found in this Application as there has been no non-utility business included in this Application.

HCHI, however, has included its "Mapping of Audited Financial Statements to Regulatory Reporting Requirements ("RRR") 2.1.7 Trial Balance" information as previously filed as 2.1.13 of the Annual Filing due April 30th for each of 2010, 2011, and 2012 as Tables 15, 16, and 17, respectively.

Each of Tables 15, 16, and 17 includes a mapping of the "Statement of Financial Position" and the "Statement of Income" on the pages that follow.

Table 15
2010 Audited Financial Statements Mapped to RRR 2.1.7 Trial Balance

	Per Audited Financial Statements			Per Trial Balance (2.1.7)		
ASSETS						
Current Assets						
Cash and bank	1005	$ 2,493,237.61	$ 2,494,212.61	Cash	1005	$ 2,494,212.61
	1010	$ 975.00				
Unbilled revenue	1120	$ 5,259,992.67	$ 5,259,992.67			
Accounts receivable	1100	$ 2,949,909.93	$ 3,192,916.17	Customer Accounts Receivable	1100	$ 2,949,909.93
	1130	$ (202,152.98)		Accumulated Provision for Uncollectible Accounts	1130	$ (202,152.98)
	1104	$ (362,459.53)		Accounts Receivable - Recoverable Work	1104	$ (362,459.53)
	1105	$ 776,431.77				
	1110	$ 31,186.98		Other Accounts Receivable	1110	$ 915,117.28
OPA conservation program	1117	$ 107,498.53	$ 107,498.53			
				Accrued Utility Revenues	1120	$ 5,259,992.67
				Prepayments	1180	$ 212,360.43
				Accounts Receivable from Associated Companies	1200	$ (582,405.27)
				Current Assets		$ 10,684,575.14
Inventory	1330	$ 1,113,623.15	$ 1,113,623.15	Plant Materials and Operating Supplies	1330	$ 1,113,623.15
Income taxes recoverable	2294	$ 33,073.00	$ 33,073.00			
Prepaid expenses	1180	$ 212,360.43	$ 212,360.43			
			$ 12,413,676.56			
Property, Plant and Equipment	1820	$ 466,496.41	$ 37,843,169.34	Distribution Station Equipment - Primary below 50 kV	1820	$ 466,496.41
	1830	$ 17,784,446.24		Poles, Towers and Fixtures	1830	$ 17,784,446.24
	1835	$ 10,250,947.52		Overhead Conductor and Devices	1835	$ 10,250,947.52
	1840	$ 515,162.56		Underground Conduit	1840	$ 515,162.56
	1845	$ 7,130,436.77		Underground Conductor and Devices	1845	$ 7,130,436.77
	1850	$ 10,962,028.89		Line Transformers	1850	$ 10,962,028.89
	1855	$ 2,379,216.55		Services	1855	$ 2,379,216.55
	1860	$ 2,949,488.17		Meters	1860	$ 2,949,488.17
	1905	$ 139,071.47		Land	1905	$ 139,071.47
	1906	$ 695,389.04		Land Rights	1906	$ 695,389.04
	1908	$ 2,029,926.31		Buildings and Fixtures	1908	$ 2,029,926.31
	1915	$ 346,626.14		Office Furniture and Equipment	1915	$ 346,626.14
	1920	$ 538,922.56		Computer Equipment - Hardware	1920	$ 538,922.56
	1925	$ 1,302,694.26		Computer Software	1925	$ 2,460,020.70
	1926	$ 1,157,326.44				
	1930	$ 1,870,373.45		Transportation Equipment	1930	$ 1,870,373.45
	1940	$ 649,121.84		Tools, Shop and Garage Equipment	1940	$ 649,121.84
	1955	$ 64,709.73		Communication Equipment	1955	$ 64,709.73
				Contributions and Grants - Credit	1995	$ (3,786,814.94)
				Other Capital Assets		$ 57,445,569.41
	2105	$ (19,431,224.60)		Accumulated Amortization - Utility Plant - PP&E	2105	$ (22,479,466.68)
	2106	$ (3,739,596.93)				
	2120	$ (218,393.48)		Accumulated Amortization - Utility Plant - Intangibles	2120	$ (218,393.48)
				Accumulated Amortization		$ (22,697,860.16)
Regulatory Assets	1508	$ 5,993.64	$ 2,576,730.30	Other Regulatory Assets	1508	$ 5,993.64
	1518	$ 159,339.12		RCVA Retail	1518	$ 159,339.12
	1521	$ 68,910.75		Special Purpose Charge Assessment Variance	1521	$ 68,910.75
	1548	$ 2,939.10		RCVA STR	1548	$ 2,939.10
	1550	$ (252,960.41)		LV Variance Account	1550	$ (252,960.41)
	1555	$ 2,703,306.05		Smart Meter Capital and Recovery Offset Variance	1555	$ 2,703,306.05
	1556	$ 646,733.05		Smart Meter OM&A Variance	1556	$ 646,733.05
	1562	$ 1,000,669.13		Deferred Payments in Lieu of Taxes	1562	$ 1,000,669.13
	1565	$ 16,284.38		CDM Expenditures and Recoveries	1565	$ 16,284.38
	1566	$ (16,284.38)		CDM Contra	1566	$ (16,284.38)
	1580	$ (901,187.87)		RSVA WMS	1580	$ (901,187.87)
	1584	$ 228,407.52		RSVA NW	1582	$ 228,407.52
	1586	$ (120,938.21)		RSVA CN	1584	$ (120,938.21)
	1588	$ (815,924.69)		RSVA Power	1588	$ (815,924.69)
	1595	$ (148,556.88)		Sub-Account Disposition of Account Balances - 2010	1595	$ (148,556.88)
				Other Assets and Deferred Charges		$ 2,576,730.30
Future Tax Asset	2296	$ 1,182,173.00	$ 1,182,173.00			
			$ 54,015,749.20	*Net Assets*		$ 49,122,637.84

	Per Audited Financial Statements			Per Trial Balance (2.1.7)		
LIABILITIES						
Current Liabilities						
Accounts payable and accrued expenses	2205	$ (818,793.55)	$ (7,051,106.69)	Accounts Payable	2205	$ (818,793.55)
	2206	$ (894,078.72)				
	2220	$ (4,880,868.37)		Miscellaneous Current and Accrued Liabilities	2220	$ (5,774,947.09)
	2250	$ (191,432.08)		Debt Retirement Charges (DRC) Payable	2250	$ (191,432.08)
	2290	$ (42,439.50)		Commodity Taxes	2290	$ (42,439.50)
	2292	$ (223,494.47)		Payroll Deductions / Expenses Payable	2292	$ (223,494.47)
Due to Haldimand County Energy Inc.	1200	$ (563,271.16)	$ (563,271.16)			
Due to Haldimand County Utilities Inc.	1200	$ (19,134.11)	$ (19,134.11)			
Current portion of long term liabilities	2210	$ (356,444.04)	$ (1,555,851.45)	Current Portion of Customer Deposits	2210	$ (356,444.04)
	2260	$ (1,188,495.46)		Current Portion of Long Term Debt	2260	$ (1,188,495.46)
				Accrual for Taxes Payments in Lieu of Taxes, etc.	2294	$ 33,073.00
				Future Income Taxes - Current	2296	$ 1,182,173.00
			$ (9,189,363.41)	*Current Liabilities*		$ (7,380,800.19)
Long Term Liabilities	2335	$ (280,533.46)	$ (9,093,432.30)	Long Term Customer Deposits	2335	$ (333,740.44)
	2336	$ (19,499.72)				
	2337	$ (33,707.26)				
	2505	$ (8,770,603.81)		Debentures Outstanding - Long Term Portion	2505	$ (8,770,603.81)
			$ (18,282,795.71)			
Deferred Credits						
Contributions in aid of construction	1995	$ (3,786,814.94)	$ (3,786,814.94)			
Less: Amortization to date	2105	$ 691,354.85	$ 691,354.85			
			$ (3,095,460.09)			
SHAREHOLDER'S EQUITY						
Capital	3005	$ (17,144,795.77)	$ (19,880,704.45)	Common Shares Issued	3005	$ (17,144,795.77)
	3030	$ (2,735,908.68)		Miscellaneous Paid-In Capital	3030	$ (2,735,908.68)
Retained Earnings	3045	$ (10,659,825.22)	$ (12,756,788.95)	Unappropriated Retained Earnings	3045	$ (10,659,825.22)
	3046	$ (2,788,408.73)		Balance Transferred From Income	3046	$ (2,788,408.73)
	3049	$ 691,445.00		Dividends Payable - Common Shares	3049	$ 691,445.00
			$ (32,637,493.40)	*Shareholders' Equity*		$ (32,637,493.40)
			$ (54,015,749.20)	*Net Liabilities and Equity*		$ (49,122,637.84)

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	Per Audited Financial Statements			Per Trial Balance (2.1.7)		
Service Revenue						
Residential	4006	$ (10,145,714.97)	$ (10,311,194.44)	Residential Energy Sales	4006	$ (10,145,714.97)
	4050	$ (165,479.47)				
General	4035	$ (9,600,703.54)	$ (8,941,376.92)	General Energy Sales	4035	$ (14,726,037.40)
	4050	$ 659,326.62				
Street lighting	4025	$ (148,749.69)	$ (160,799.18)	Street Lighting Energy Sales	4025	$ (148,749.69)
	4050	$ (12,049.49)				
Sentinel lighting	4030	$ (23,191.44)	$ (23,322.99)	Sentinel Lighting Energy Sales	4030	$ (23,191.44)
	4050	$ (131.55)				
Embedded Distributor	4035	$ (5,125,333.86)	$ (5,530,280.36)			
	4050	$ (404,946.50)		Revenue Adjustment	4050	$ (109,433.49)
Retailer	4055	$ (4,361,324.49)	$ (4,593,215.29)	Energy Sales for Resale	4055	$ (4,361,324.49)
	4050	$ (231,890.80)				
Retail transmission and low voltage	4066	$ (2,507,740.89)	$ (4,969,885.59)	Billed NW	4066	$ (2,507,740.89)
	4068	$ (2,314,334.78)		Billed CN	4068	$ (2,314,334.78)
	4075	$ (208,430.56)		Billed - LV	4075	$ (208,430.56)
	4050	$ 60,620.64				
Regulatory	4062	$ (2,894,502.86)	$ (2,909,385.80)	Billed WMS	4062	$ (2,894,502.86)
	4050	$ (14,882.94)				
				Sales of Electricity		$ (37,439,460.57)
Distribution services	4080	$ (13,024,494.40)	$ (13,024,494.40)	Distribution Services Revenue	4080	$ (13,024,494.40)
			$ (50,463,954.97)			
Cost of Power	4705	$ 29,560,189.18	$ 37,439,460.57			
	4708	$ 2,909,385.80				
	4714	$ 2,490,966.04				
	4716	$ 2,287,906.29				
	4750	$ 191,013.26				
Gross Margin on Service Revenue			$ (13,024,494.40)			
Other Operating Revenue	4082	$ (31,747.00)	$ (1,283,684.93)	Retail Services Revenue	4082	$ (31,747.00)
	4084	$ (1,044.75)		Service Transaction Requests (STR) Revenue	4084	$ (1,044.75)
				Revenue from Services		$ (13,057,286.15)
	4210	$ (80,922.76)		Rent from Electric Property	4210	$ (80,922.76)
	4225	$ (349,416.21)		Late Payment Charges	4225	$ (349,416.21)
	4235	$ (136,246.69)		Miscellaneous Service Revenues	4235	$ (136,246.69)
				Other Operating Revenues		$ (566,585.66)
	4324	$ (94,691.94)		Special Purpose Charge Recovery	4324	$ (94,691.94)
	4325	$ (18,976.31)		Revenues from Merchandising, Jobbing, Etc.	4325	$ (18,976.31)
	4355	$ (12,203.30)		Gain on Disposition of Utility and Other Property	4355	$ (12,203.30)
	4360	$ 6,684.69		Loss on Disposition of Utility and Other Property	4360	$ 6,684.69
	4375	$ (426,735.07)		Revenues from Non-Utility Operations	4375	$ (426,735.07)
	4380	$ 1.44		Expenses of Non-Utility Operations	4380	$ 1.44
	4390	$ (68,196.38)		Miscellaneous Non-Operating Income	4390	$ (68,196.38)
				Other Income / Deductions		$ (614,116.87)
	4405	$ (70,190.65)		Interest and Dividend Income	4405	$ (70,190.65)
				Total Revenues		$ (51,747,639.90)
				Power Purchased	4705	$ 29,560,189.18
				Charges - WMS	4708	$ 2,909,385.80
				Charges - NW	4714	$ 2,490,966.04
				Charges - CN	4716	$ 2,287,906.29
				Charges - LV	4750	$ 191,013.26
				Other Power Supply Expenses		$ 37,439,460.57
			$ (14,308,179.33)			

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	Per Audited Financial Statements			Per Trial Balance (2.1.7)		
Expenses						
Distribution, operation and maintenance	5005	$ 468,918.09	$ 3,642,500.45	Operation Supervision and Engineering	5005	$ 468,918.09
	5012	$ 18,504.47		Distribution Station Equipment - Operation Supplies and Expenses	5017	$ 18,504.47
	5016	$ 19,726.82		Distribution Station Equipment - Operation Labour	5016	$ 19,726.82
	5020	$ 140,890.52		Overhead Distribution Lines and Feeders - Operation Labour	5020	$ 140,890.52
	5035	$ 201,041.40		Overhead Distribution Transformers - Operation	5035	$ 201,041.40
	5040	$ 80,920.00		Underground Distribution Lines and Feeders - Operation Labour	5040	$ 80,920.00
	5055	$ 13,295.06		Underground Distribution Transformers - Operation	5055	$ 13,295.06
	5065	$ 243,038.35		Meter Expense	5065	$ 243,038.35
	5070	$ 13,684.28		Customer Premises - Operation Labour	5070	$ 13,684.28
	5085	$ 250,048.26		Miscellaneous Distribution Expense	5085	$ 250,048.26
	5105	$ 129,855.79		Maintenance Supervision and Engineering	5105	$ 129,855.79
	5110	$ 1,943.49				
	5114	$ 106,108.59		Maintenance of Distribution Station Equipment	5114	$ 108,052.08
	5120	$ 399,964.63		Maintenance of Poles, Towers and Fixtures	5120	$ 399,964.63
	5125	$ 643,301.19		Maintenance of Overhead Conductors and Devices	5125	$ 643,301.19
	5130	$ 164,876.41		Maintenance of Overhead Services	5130	$ 164,876.41
	5135	$ 312,680.35		Overhead Distribution Lines and Feeders - Right of Way	5135	$ 312,680.35
	5145	$ 5,357.94		Maintenance of Underground Conduit	5145	$ 5,357.94
	5150	$ 26,972.72		Maintenance of Underground Conductor and Devices	5150	$ 26,972.72
	5155	$ 152,675.75		Maintenance of Underground Services	5155	$ 152,675.75
	5160	$ 231,181.76		Maintenance of Line Transformers	5160	$ 231,181.76
	5175	$ 12,715.46		Maintenance of Meters	5175	$ 12,715.46
	5195	$ 4,799.12		Maintenance of Other Installations on Customer Premises	5195	$ 4,799.12
				Distribution Expenses		$ 3,642,500.45
Billing and collecting	5305	$ 142,674.24	$ 1,305,987.68	Supervision	5305	$ 142,674.24
	5310	$ 272,679.94		Meter Reading Expense	5310	$ 272,679.94
	5315	$ 528,226.50		Customer Billing	5315	$ 528,226.50
	5320	$ 258,457.74		Collecting	5320	$ 258,457.74
	5325	$ 0.30		Collecting - Cash Over and Short	5325	$ 0.30
	5335	$ 39,404.66		Bad Debt Expense	5335	$ 39,404.66
	5340	$ 143,285.18				
	5350	$ (78,740.88)		Miscellaneous Customer Accounts Expenses	5340	$ 64,544.30
				Billing Collecting		$ 1,305,987.68
Community Relations	5410	$ 22,022.73	$ 42,642.63	Community Relations - Sundry	5410	$ 22,022.73
	5415	$ 20,619.90		Energy Conservation	5415	$ 20,619.90
				Community Relations		$ 42,642.63
Directors	5605	$ 48,831.75	$ 48,831.75	Executive Salaries and Expenses	5605	$ 48,831.75
General Administration	5610	$ 600,034.19	$ 1,854,560.57	Management Salaries and Expenses	5610	$ 600,034.19
	5615	$ 489,221.80		General Administrative Salaries and Expenses	5615	$ 489,221.80
	5620	$ 93,266.78		Office Supplies and Expenses	5620	$ 93,266.78
	5630	$ 254,845.85		Outside Services Employed	5630	$ 254,845.85
	5635	$ 21,858.12		Property Insurance	5635	$ 21,858.12
	5655	$ 199,669.01		Regulatory Expenses	5655	$ 199,669.01
	5665	$ 29,833.03		Miscellaneous General Expenses	5665	$ 29,833.03
	5681	$ 94,691.94		Special Purpose Charge Expense	5681	$ 94,691.94
				Administration General Expenses		$ 1,832,252.47
	6105	$ 71,139.85				
			$ 6,894,523.08			
Amortization	5705	$ 2,280,743.59	$ 2,973,031.81	Amortization Expense - Property, Plant and Equipment	5705	$ 2,807,745.68
	5706	$ 671,567.73				
	5715	$ 20,720.49		Amortization of Intangibles and Other Electric Plant	5715	$ 20,720.49
Less: Amortization of contributions in aid of construction	5715	$ (144,565.64)	$ (144,565.64)			
			$ 2,828,466.17	*Amortization Expenses*		$ 2,828,466.17
			$ 9,722,989.25			
Income Before Interest and Income Taxes						
Interest Expense	6005	$ 538,899.08	$ 563,732.35	Interest on Long Term Debt	6005	$ 538,899.08
	6035	$ 24,833.27		Other Interest Expense	6035	$ 24,833.27
				Interest Expenses		$ 563,732.35
Income Before Taxes			$ (4,021,457.73)			
Income taxes						
Current	6110	$ 1,574,922.00	$ 1,574,922.00	Income Taxes	6110	$ 1,574,922.00
Future	6115	$ (341,873.00)	$ (341,873.00)	Provision for Future Income Taxes	6115	$ (341,873.00)
				Taxes Other Than Income Taxes	6105	$ 71,139.85
			$ 1,233,049.00	*Taxes*		$ 1,304,188.85
				Total Expenses		$ 48,959,231.17
Net Income			**$ (2,788,408.73)**	*Profit / Loss*		$ (2,788,408.73)

Table 16
2011 Audited Financial Statements Mapped to RRR 2.1.7 Trial Balance

	Per Audited Financial Statements			Per Trial Balance (2.1.7)		
ASSETS						
Current Assets						
Cash and bank	1005	$ 3,940,785.70	$ 3,941,760.70	Cash	1005	$ 3,941,760.70
	1010	$ 975.00				
Unbilled revenue	1120	$ 5,422,771.85	$ 5,422,771.85			
Accounts receivable	1100	$ 3,407,872.69	$ 3,331,451.90	Customer Accounts Receivable	1100	$ 3,407,872.69
	1130	$ (207,144.86)		Accumulated Provision for Uncollectible Accounts	1130	$ (207,144.86)
	1104	$ (327,863.34)		Accounts Receivable - Recoverable Work	1104	$ (327,863.34)
	1105	$ 424,942.10				
	1110	$ 21,888.96		Other Accounts Receivable	1110	$ 636,636.23
	1115	$ 11,756.35				
				Accrued Utility Revenues	1120	$ 5,422,771.85
				Prepayments	1180	$ 270,855.34
				Current Assets		$ 13,144,888.61
Inventory	1330	$ 1,254,483.81	$ 1,254,483.81	Plant Materials and Operating Supplies	1330	$ 1,254,483.81
Income taxes recoverable	2294	$ 585,578.00	$ 585,578.00	*Inventory*		
Prepaid expenses	1180	$ 270,855.34	$ 270,855.34			
			$ 14,806,901.60			
Property, Plant and Equipment	1820	$ 466,496.41	$ 39,793,679.51	Distribution Station Equipment - Primary below 50 kV	1820	$ 466,496.41
	1830	$ 19,408,683.08		Poles, Towers and Fixtures	1830	$ 19,408,683.08
	1835	$ 11,757,487.96		Overhead Conductor and Devices	1835	$ 11,757,487.96
	1840	$ 633,780.53		Underground Conduit	1840	$ 633,780.53
	1845	$ 7,292,190.11		Underground Conductor and Devices	1845	$ 7,292,190.11
	1850	$ 11,614,067.55		Line Transformers	1850	$ 11,614,067.55
	1855	$ 2,551,800.89		Services	1855	$ 2,551,800.89
	1860	$ 3,131,705.83		Meters	1860	$ 3,131,705.83
	1905	$ 131,279.77		Land	1905	$ 131,279.77
	1906	$ 695,389.04		Land Rights	1906	$ 695,389.04
	1908	$ 2,168,015.94		Buildings and Fixtures	1908	$ 2,168,015.94
	1915	$ 363,141.26		Office Furniture and Equipment	1915	$ 363,141.26
	1920	$ 517,536.62		Computer Equipment - Hardware	1920	$ 517,536.62
	1925	$ 1,349,368.73		Computer Software	1925	$ 2,584,483.98
	1926	$ 1,235,115.25				
	1930	$ 2,087,568.97		Transportation Equipment	1930	$ 2,087,568.97
	1940	$ 707,839.33		Tools, Shop and Garage Equipment	1940	$ 707,839.33
	1955	$ 68,075.09		Communication Equipment	1955	$ 68,075.09
				Contributions and Grants - Credit	1995	$ (3,953,284.41)
				Other Capital Assets		$ 62,226,257.95
	2105	$ (21,828,986.37)		Accumulated Amortization - Utility Plant - PP&E	2105	$ (25,300,568.42)
	2106	$ (4,317,762.50)				
	2120	$ (239,113.98)		Accumulated Amortization - Utility Plant - Intangibles	2120	$ (239,113.98)
				Accumulated Amortization		$ (25,539,682.40)
Regulatory Assets	1508	$ 6,081.00	$ 2,284,827.93	Other Regulatory Assets	1508	$ 6,081.00
	1518	$ 240,878.74		RCVA Retail	1518	$ 240,878.74
	1521	$ 22,846.66		Special Purpose Charge Assessment Variance	1521	$ 22,846.66
	1548	$ 4,360.38		RCVA STR	1548	$ 4,360.38
	1550	$ (113,364.35)		LV Variance Account	1550	$ (113,425.84)
	1555	$ 2,260,703.95		Smart Meter Capital and Recovery Offset Variance	1555	$ 2,260,703.95
	1556	$ 1,248,084.45		Smart Meter OM&A Variance	1556	$ 1,248,084.45
	1562	$ 1,011,900.65		Deferred Payments in Lieu of Taxes	1562	$ 1,011,900.65
	1565	$ 16,284.38		CDM Expenditures and Recoveries	1565	$ 16,284.38
	1566	$ (16,284.38)		CDM Contra	1566	$ (16,284.38)
	1580	$ (1,238,045.21)		RSVA WMS	1580	$ (1,252,069.79)
	1584	$ (3,825.57)		RSVA NW	1584	$ (16,004.08)
	1586	$ (218,322.75)		RSVA CN	1586	$ (228,651.43)
	1588	$ (591,118.54)		RSVA Power	1588	$ (747,611.10)
	1595	$ (345,351.48)		Sub-Account Disposition of Account Balances - 2010	1595	$ (345,351.48)
				Other Assets and Deferred Charges		$ 2,091,742.11
Future Tax Asset	2296	$ 1,271,300.00	$ 1,271,300.00			
			$ 58,156,709.04	*Net Assets*		$ 53,177,690.08

	Per Audited Financial Statements			Per Trial Balance (2.1.7)		
LIABILITIES						
Current Liabilities						
Accounts payable and accrued expenses	2205	$ (1,486,300.45)	$ (7,696,115.21)	Accounts Payable	2205	$ (1,486,300.45)
	2206	$ (840,142.23)				
	2220	$ (4,954,275.34)		Miscellaneous Current and Accrued Liabilities	2220	$ (5,794,417.57)
	2250	$ (183,846.14)		Debt Retirement Charges (DRC) Payable	2250	$ (183,846.14)
	2290	$ -		Commodity Taxes	2290	$ 11,756.35
	2292	$ (231,551.05)		Payroll Deductions / Expenses Payable	2292	$ (231,551.05)
OPA conservation program	1117	$ (3,280.65)	$ (3,280.65)			
Due to Haldimand County Energy Inc.	1200	$ (623,474.48)	$ (623,474.48)	Accounts Payable to Associated Companies	2240	$ (640,964.08)
Due to Haldimand County Utilities Inc.	1200	$ (17,489.60)	$ (17,489.60)			
Current portion of long term liabilities	2210	$ (35,160.45)	$ (1,023,661.91)	Current Portion of Customer Deposits	2210	$ (35,160.45)
	2260	$ (988,501.46)		Current Portion of Long Term Debt	2260	$ (988,501.46)
				Accrual for Taxes Payments in Lieu of Taxes, etc.	2294	$ 585,578.00
				Future Income Taxes - Current	2296	$ 1,271,300.00
			$ (9,364,021.85)	*Current Liabilities*		$ (7,492,106.85)
Long Term Liabilities	2335	$ (314,222.31)	$ (11,386,158.05)	Long Term Customer Deposits	2335	$ (438,320.70)
	2336	$ (9,817.99)		*Non-Current Liabilities*		
	2337	$ (114,280.40)				
	2505	$ (10,947,837.35)		Debentures Outstanding - Long Term Portion	2505	$ (10,947,837.35)
				Other Liabilities Deferred Credit		
			$ (20,750,179.90)			
Deferred Credits						
Contributions in aid of construction	1995	$ (3,953,284.41)	$ (3,953,284.41)			
Less: Amortization to date	2105	$ 846,180.45	$ 846,180.45			
			$ (3,107,103.96)			
SHAREHOLDER'S EQUITY						
Capital	3005	$ (17,144,795.77)	$ (19,880,704.45)	Common Shares Issued	3005	$ (17,144,795.77)
	3030	$ (2,735,908.68)		Miscellaneous Paid-In Capital	3030	$ (2,735,908.68)
Retained Earnings	3045	$ (12,756,788.95)	$ (14,418,720.73)	Unappropriated Retained Earnings	3045	$ (12,756,788.95)
	3046	$ (2,378,681.78)		Balance Transferred From Income	3046	$ (2,378,681.78)
	3049	$ 716,750.00		Dividends Payable - Common Shares	3049	$ 716,750.00
			$ (34,299,425.18)	*Shareholders' Equity*		$ (34,299,425.18)
			$ (58,156,709.04)	*Net Liabilities and Equity*		$ (53,177,690.08)

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	Per Audited Financial Statements			Per Trial Balance (2.1.7)		
Service Revenue						
Residential	4006	$ (11,122,783.75)	$ (11,240,325.32)	Residential Energy Sales	4006	$ (11,122,783.75)
	4050	$ (117,541.57)				
General	4035	$ (10,524,258.83)	$ (10,434,534.89)	General Energy Sales	4035	$ (15,912,226.58)
	4050	$ 89,723.94				
Street lighting	4025	$ (158,975.23)	$ (160,903.98)	Street Lighting Energy Sales	4025	$ (158,975.23)
	4050	$ (1,928.75)				
Sentinel lighting	4030	$ (23,996.77)	$ (24,383.06)	Sentinel Lighting Energy Sales	4030	$ (23,996.77)
	4050	$ (386.29)				
Embedded Distributor	4035	$ (5,387,967.75)	$ (5,398,453.56)			
	4050	$ (10,485.81)		Revenue Adjustment	4050	$ (222,705.80)
Retailer	4055	$ (4,668,866.49)	$ (4,816,832.62)	Energy Sales for Resale	4055	$ (4,668,866.49)
	4050	$ (147,966.13)				
Retail transmission and low voltage	4066	$ (2,754,532.05)	$ (5,379,871.25)	Billed NW	4066	$ (2,754,532.05)
	4068	$ (2,444,072.19)		Billed CN	4068	$ (2,444,072.19)
	4075	$ (136,999.21)		Billed - LV	4075	$ (136,999.21)
	4050	$ (44,267.80)				
Regulatory	4062	$ (2,935,683.32)	$ (2,925,536.71)	Billed WMS	4062	$ (2,935,683.32)
	4050	$ 10,146.61				
				Sales of Electricity		$ (40,380,841.39)
Distribution services	4080	$ (12,875,587.92)	$ (12,875,587.92)	Distribution Services Revenue	4080	$ (12,875,587.92)
			$ (53,256,429.31)			
Cost of Power	4705	$ 32,075,433.42	$ 40,380,841.38			
	4708	$ 2,925,536.71				
	4714	$ 2,788,019.73				
	4716	$ 2,455,299.15				
	4750	$ 136,552.37				
Gross Margin on Service Revenue			$ (12,875,587.93)			
Other Operating Revenue	4082	$ (29,584.00)	$ (1,279,957.55)	Retail Services Revenue	4082	$ (29,584.00)
	4084	$ (841.25)		Service Transaction Requests (STR) Revenue	4084	$ (841.25)
				Revenue from Services		$ (12,906,013.17)
	4210	$ (86,986.81)		Rent from Electric Property	4210	$ (86,986.81)
	4225	$ (289,018.38)		Late Payment Charges	4225	$ (289,018.38)
	4235	$ (109,528.53)		Miscellaneous Service Revenues	4235	$ (109,528.53)
				Other Operating Revenues		$ (485,533.72)
	4324	$ (46,517.20)		Special Purpose Charge Recovery	4324	$ (46,517.20)
	4325	$ (22,402.42)		Revenues from Merchandising, Jobbing, Etc.	4325	$ (22,402.42)
	4355	$ (24,427.15)		Gain on Disposition of Utility and Other Property	4355	$ (24,427.15)
	4360	$ 3,077.55		Loss on Disposition of Utility and Other Property	4360	$ 3,077.55
	4375	$ (423,802.47)		Revenues from Non-Utility Operations	4375	$ (423,802.47)
	4380	$ -		Expenses of Non-Utility Operations	4380	$ -
	4390	$ (144,190.31)		Miscellaneous Non-Operating Income	4390	$ (144,190.31)
				Other Income / Deductions		$ (658,262.00)
	4405	$ (105,736.58)		Interest and Dividend Income	4405	$ (105,736.58)
				Total Revenues		$ (54,536,386.86)
				Power Purchased	4705	$ 32,075,433.42
				Charges - WMS	4708	$ 2,925,536.71
				Charges - NW	4714	$ 2,788,019.73
				Charges - CN	4716	$ 2,455,299.15
				Charges - LV	4750	$ 136,552.37
				Other Power Supply Expenses		$ 40,380,841.38
			$ (14,155,545.48)			

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	Per Audited Financial Statements			Per Trial Balance (2.1.7)		
Expenses						
Distribution, operation and maintenance	5005	$ 556,881.03	$ 4,128,598.38	Operation Supervision and Engineering	5005	$ 556,881.03
	5012	$ 16,802.70		Distribution Station Equipment - Operation Supplies and Expenses	5017	$ 16,802.70
	5016	$ 17,180.62		Distribution Station Equipment - Operation Labour	5016	$ 17,180.62
	5020	$ 171,848.78		Overhead Distribution Lines and Feeders - Operation Labour	5020	$ 171,848.78
	5035	$ 203,736.44		Overhead Distribution Transformers - Operation	5035	$ 203,736.44
	5040	$ 75,942.06		Underground Distribution Lines and Feeders - Operation Labour	5040	$ 75,942.06
	5055	$ 17,611.23		Underground Distribution Transformers - Operation	5055	$ 17,611.23
	5065	$ 234,766.64		Meter Expense	5065	$ 234,766.64
	5070	$ 5,474.17		Customer Premises - Operation Labour	5070	$ 5,474.17
	5085	$ 366,366.55		Miscellaneous Distribution Expense	5085	$ 366,366.55
	5105	$ 127,417.25		Maintenance Supervision and Engineering	5105	$ 127,417.25
	5110	$ 1,979.35				
	5114	$ 235,177.89		Maintenance of Distribution Station Equipment	5114	$ 237,157.24
	5120	$ 298,067.05		Maintenance of Poles, Towers and Fixtures	5120	$ 298,067.05
	5125	$ 960,875.09		Maintenance of Overhead Conductors and Devices	5125	$ 960,875.09
	5130	$ 189,621.58		Maintenance of Overhead Services	5130	$ 189,621.58
	5135	$ 191,905.58		Overhead Distribution Lines and Feeders - Right of Way	5135	$ 191,905.58
	5145	$ 158.34		Maintenance of Underground Conduit	5145	$ 158.34
	5150	$ 17,569.77		Maintenance of Underground Conductor and Devices	5150	$ 17,569.77
	5155	$ 137,098.00		Maintenance of Underground Services	5155	$ 137,098.00
	5160	$ 275,482.18		Maintenance of Line Transformers	5160	$ 275,482.18
	5175	$ 24,169.00		Maintenance of Meters	5175	$ 24,169.00
	5195	$ 2,467.08		Maintenance of Other Installations on Customer Premises	5195	$ 2,467.08
				Distribution Expenses		$ 4,128,598.38
Billing and collecting	5305	$ 143,307.23	$ 1,154,951.63	Supervision	5305	$ 143,307.23
	5310	$ 140,028.55		Meter Reading Expense	5310	$ 140,028.55
	5315	$ 523,652.85		Customer Billing	5315	$ 523,652.85
	5320	$ 225,144.50		Collecting	5320	$ 225,144.50
	5325	$ 10.10		Collecting - Cash Over and Short	5325	$ 10.10
	5335	$ 57,029.28		Bad Debt Expense	5335	$ 57,029.28
	5340	$ 145,825.83				
	5350	$ (80,046.71)		Miscellaneous Customer Accounts Expenses	5340	$ 65,779.12
				Billing Collecting		$ 1,154,951.63
Community Relations	5410	$ 28,493.03	$ 45,425.52	Community Relations - Sundry	5410	$ 28,493.03
	5415	$ 16,932.49		Energy Conservation	5415	$ 16,932.49
				Community Relations		$ 45,425.52
Directors	5605	$ 57,206.87	$ 57,206.87	Executive Salaries and Expenses	5605	$ 57,206.87
General Administration	5610	$ 660,504.98	$ 1,972,173.53	Management Salaries and Expenses	5610	$ 660,504.98
	5615	$ 543,625.81		General Administrative Salaries and Expenses	5615	$ 543,625.81
	5620	$ 122,130.96		Office Supplies and Expenses	5620	$ 122,130.96
	5630	$ 405,836.15		Outside Services Employed	5630	$ 405,836.15
	5635	$ 22,125.68		Property Insurance	5635	$ 22,125.68
	5655	$ 112,522.51		Regulatory Expenses	5655	$ 112,522.51
	5665	$ (5,285.25)		Miscellaneous General Expenses	5665	$ (5,285.25)
	5681	$ 46,517.20		Special Purpose Charge Expense	5681	$ 46,517.20
				Administration General Expenses		$ 1,965,184.91
	6205	$ 16,500.00				
	6105	$ 47,695.49				
			$ 7,358,355.93			
Amortization	5705	$ 2,397,761.77	$ 3,129,016.44	Amortization Expense - Property, Plant and Equipment	5705	$ 2,953,470.34
	5706	$ 710,534.17				
	5715	$ 20,720.50		Amortization of Intangibles and Other Electric Plant	5715	$ 20,720.50
Less: Amortization of contributions in aid of construction	5715	$ (154,825.60)	$ (154,825.60)			
			$ 2,974,190.84	*Amortization Expenses*		$ 2,974,190.84
			$ 10,332,546.77			
Income Before Interest and Income Taxes			$ (3,822,998.71)			
Interest Expense	6005	$ 437,845.72	$ 485,500.93	Interest on Long Term Debt	6005	$ 437,845.72
	6035	$ 47,655.21		Other Interest Expense	6035	$ 47,655.21
				Interest Expenses		$ 485,500.93
Income Before Taxes			$ (3,337,497.78)			
Income taxes						
Current	6110	$ 1,047,943.00	$ 1,047,943.00	Income Taxes	6110	$ 1,047,943.00
Future	6115	$ (89,127.00)	$ (89,127.00)	Provision for Future Income Taxes	6115	$ (89,127.00)
				Taxes Other Than Income Taxes	6105	$ 47,695.49
			$ 958,816.00	*Taxes*		$ 1,006,511.49
				Donations - LEAP Funding	6205	$ 16,500.00
				Other Deductions		
				Total Expenses		$ 52,157,705.08
Net Income			**$ (2,378,681.78)**	*Profit / Loss*		$ (2,378,681.78)

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Table 17
2012 Audited Financial Statements Mapped to RRR 2.1.7 Trial Balance

	Per Audited Financial Statements			Per Trial Balance (2.1.7)		
ASSETS						
Current Assets						
Cash and bank	1005	$ 5,732,912.53	$ 5,733,887.53	Cash	1005	$ 5,733,887.53
	1010	$ 975.00				
Unbilled revenue	1120	$ 5,589,541.69	$ 5,589,541.69			
Accounts receivable	1100	$ 4,690,064.90	$ 4,509,455.90	Customer Accounts Receivable	1100	$ 4,690,064.90
	1130	$ (200,171.62)		Accumulated Provision for Uncollectible Accounts	1130	$ (200,171.62)
	1104	$ (406,122.02)		Accounts Receivable - Recoverable Work	1104	$ (406,122.02)
	1105	$ 405,661.67				
	1110	$ 20,022.97		Other Accounts Receivable	1110	$ 425,844.61
OPA conservation program	1117	$ 159.97	$ 159.97	Accrued Utility Revenues	1120	$ 5,589,541.69
				Prepayments	1180	$ 276,993.51
				Current Assets		$ 16,110,038.60
Inventory	1330	$ 1,334,138.87	$ 1,334,138.87	Plant Materials and Operating Supplies	1330	$ 1,334,138.87
Income taxes recoverable	2294	$ 588,086.00	$ 588,086.00	*Inventory*		
Prepaid expenses	1180	$ 276,993.51	$ 276,993.51			
			$ 18,032,263.47	Other Regulatory Assets	1508	$ 6,168.36
				RCVA Retail	1518	$ 325,151.28
				Special Purpose Charge Assessment Variance	1521	$ -
				RCVA STR	1548	$ 6,118.06
				LV Variance Account	1550	$ (52,744.37)
				Smart Meter Capital and Recovery Offset Variance	1555	$ (4,491.34)
				Smart Meter OM&A Variance	1556	$ -
				Deferred Payments in Lieu of Taxes	1562	$ -
				CDM Expenditures and Recoveries	1565	$ 16,284.38
				CDM Contra	1566	$ (16,284.38)
				RSVA WMS	1580	$ (1,386,219.11)
				RSVA NW	1584	$ (46,447.10)
				RSVA CN	1586	$ (39,049.53)
				RSVA Power	1588	$ (207,306.99)
				RSVA Global Adjustment	1589	$ 489,658.18
				Sub-Account Disposition of Account Balances - 2010	1595	$ (1,197,158.15)
				Other Assets and Deferred Charges		$ (2,106,320.71)
Property, Plant and Equipment	1820	$ 466,496.41	$ 45,030,722.63	Distribution Station Equipment - Primary below 50 kV	1820	$ 466,496.41
	1830	$ 20,627,452.14		Poles, Towers and Fixtures	1830	$ 20,627,452.14
	1835	$ 13,556,975.01		Overhead Conductor and Devices	1835	$ 13,556,975.01
	1840	$ 1,366,195.59		Underground Conduit	1840	$ 1,366,195.59
	1845	$ 7,702,253.91		Underground Conductor and Devices	1845	$ 7,702,253.91
	1850	$ 12,387,904.21		Line Transformers	1850	$ 12,387,904.21
	1855	$ 2,683,091.60		Services	1855	$ 2,683,091.60
	1860	$ 6,758,882.22		Meters	1860	$ 6,758,882.22
	1905	$ 127,140.02		Land	1905	$ 127,140.02
	1612	$ 695,389.04		Land Rights	1906	$ 695,389.04
	1908	$ 2,190,517.84		Buildings and Fixtures	1908	$ 2,190,517.84
	1915	$ 365,635.02		Office Furniture and Equipment	1915	$ 365,635.02
	1920	$ 585,094.04		Computer Equipment - Hardware	1920	$ 585,094.04
	1611	$ 2,765,070.33		Computer Software	1925	$ 2,765,070.33
	1930	$ 2,207,644.86		Transportation Equipment	1930	$ 2,207,644.86
	1940	$ 795,038.16		Tools, Shop and Garage Equipment	1940	$ 795,038.16
	1955	$ 68,075.09		Communication Equipment	1955	$ 68,075.09
				Contributions and Grants - Credit	1995	$ (4,143,672.05)
				Capital Assets		$ 71,205,183.44
	2105	$ (25,138,711.64)		Accumulated Amortization - Utility Plant - PP&E	2105	$ (29,050,797.79)
	2106	$ (4,919,529.98)				
	2120	$ (259,891.24)		Accumulated Amortization - Utility Plant - Intangibles	2120	$ (259,891.24)
				Accumulated Amortization		$ (29,310,689.03)
Future Tax Asset	1495	$ 1,615,829.00	$ 1,615,829.00			
			$ 64,678,815.10	*Net Assets*		$ 57,232,351.17

	Per Audited Financial Statements			Per Trial Balance (2.1.7)		
LIABILITIES						
Current Liabilities						
Accounts payable and accrued expenses	2205	$ (792,336.15)	$ (9,148,217.54)	Accounts Payable	2205	$ (792,336.15)
	2206	$ (933,954.15)				
	2220	$ (6,903,285.98)		Miscellaneous Current and Accrued Liabilities	2220	$ (7,837,240.13)
	2250	$ (184,020.23)		Debt Retirement Charges (DRC) Payable	2250	$ (184,020.23)
	2290	$ (90,710.06)		Commodity Taxes	2290	$ (90,710.06)
	2292	$ (243,910.97)		Payroll Deductions / Expenses Payable	2292	$ (243,910.97)
Due to Haldimand County Energy Inc.	1200	$ (738,282.96)	$ (738,282.96)	Accounts Payable to Associated Companies	2240	$ (765,108.58)
Due to Haldimand County Utilities Inc.	1200	$ (26,825.62)	$ (26,825.62)			
Current portion of long term liabilities	2210	$ (55,346.00)	$ (1,354,948.04)	Current Portion of Customer Deposits	2210	$ (55,346.00)
	2260	$ (1,299,602.04)		Current Portion of Long Term Debt	2260	$ (1,299,602.04)
				Accrual for Taxes Payments in Lieu of Taxes, etc.	2294	$ 588,086.00
				Future Income Taxes - Current	2296	$ 1,615,829.00
			$ (11,268,274.16)	*Current Liabilities*		$ (9,064,359.16)
Regulatory Liabilities	1508	$ 6,168.36	$ (2,106,320.71)			
	1518	$ 325,151.28				
	1521	$ -				
	1548	$ 6,118.06				
	1550	$ (52,744.37)				
	1555	$ (4,491.34)				
	1556	$ -				
	1562	$ -				
	1565	$ 16,284.38				
	1566	$ (16,284.38)				
	1580	$ (1,386,219.11)				
	1584	$ (46,447.10)				
	1586	$ (39,049.53)				
	1588	$ (207,306.99)				
	1589	$ 489,658.18				
	1595	$ (1,197,158.15)				
Long Term Liabilities	2335	$ (320,442.01)	$ (13,698,310.24)	Long Term Customer Deposits	2335	$ (448,875.43)
	2336	$ (3,395.17)				
	2337	$ (125,038.25)		Collateral Funds Liability	2340	$ (40,290.50)
	2340	$ (40,290.50)		*Non-Current Liabilities*		$ (489,165.93)
	2505	$ (13,209,144.31)				
				Debentures Outstanding - Long Term Portion	2505	$ (13,209,144.31)
			$ (27,072,905.11)	*Other Liabilities Deferred Credit & Long term debt*		
Deferred Credits						
Contributions in aid of construction	1995	$ (4,143,672.05)	$ (4,143,672.05)			
Less: Amortization to date	2105	$ 1,007,443.83	$ 1,007,443.83			
			$ (3,136,228.22)			
SHAREHOLDER'S EQUITY						
Capital	3005	$ (17,144,795.77)	$ (19,880,704.45)	Common Shares Issued	3005	$ (17,144,795.77)
	3030	$ (2,735,908.68)		Miscellaneous Paid-In Capital	3030	$ (2,735,908.68)
Retained Earnings	3045	$ (14,418,720.73)	$ (14,588,977.32)	Unappropriated Retained Earnings	3045	$ (14,418,720.73)
	3046	$ (781,585.59)		Balance Transferred From Income	3046	$ (781,585.59)
	3049	$ 611,329.00		Dividends Payable - Common Shares	3049	$ 611,329.00
			$ (34,469,681.77)	*Shareholders' Equity*		$ (34,469,681.77)
			$ (64,678,815.10)	*Net Liabilities and Equity*		$ (57,232,351.17)

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	Per Audited Financial Statements			Per Trial Balance (2.1.7)		
Service Revenue						
Residential	4006	$ (12,316,503.91)	$ (12,420,909.68)	Residential Energy Sales	4006	$ (12,316,503.91)
	4050	$ (104,405.77)				
General	4035	$ (8,898,959.14)	$ (8,843,891.08)	General Energy Sales	4035	$ (14,173,689.01)
	4050	$ 55,068.06				
Street lighting	4025	$ (37,930.03)	$ (18,911.40)	Street Lighting Energy Sales	4025	$ (37,930.03)
	4050	$ 19,018.63				
Sentinel lighting	4030	$ (23,770.48)	$ (23,492.98)	Sentinel Lighting Energy Sales	4030	$ (23,770.48)
	4050	$ 277.50				
Embedded Distributor	4035	$ (5,274,729.87)	$ (5,258,987.86)			
	4050	$ 15,742.01		Revenue Adjustment	4050	$ (38,620.88)
Retailer	4055	$ (6,166,971.25)	$ (6,216,878.46)	Energy Sales for Resale	4055	$ (6,166,971.25)
	4050	$ (49,907.21)				
Retail transmission and low voltage	4066	$ (2,707,206.46)	$ (5,038,538.98)	Billed NW	4066	$ (2,707,206.46)
	4068	$ (2,260,991.23)		Billed CN	4068	$ (2,260,991.23)
	4075	$ (82,506.56)		Billed - LV	4075	$ (82,506.56)
	4050	$ 12,165.27				
Regulatory	4062	$ (2,087,350.60)	$ (2,073,929.97)	Billed WMS	4062	$ (2,087,350.60)
	4050	$ 13,420.63				
				Sales of Electricity		$ (39,895,540.41)
Distribution services	4080	$ (14,285,046.47)	$ (14,343,230.41)	Distribution Services Revenue	4080	$ (14,285,046.47)
SSS Administration Revenue	4086	$ (58,183.94)		SSS Administration Revenue	4086	$ (58,183.94)
			$ (54,238,770.82)			
Cost of Power	4705	$ 22,231,490.98	$ 39,895,540.41			
	4707	$ 10,551,580.48				
	4708	$ 2,073,929.97				
	4714	$ 2,703,950.60				
	4716	$ 2,252,196.15				
	4750	$ 82,392.23				
Gross Margin on Service Revenue			$ (14,343,230.41)			
Other Operating Revenue	4082	$ (26,639.20)	$ (1,218,855.80)	Retail Services Revenue	4082	$ (26,639.20)
	4084	$ (497.75)		Service Transaction Requests (STR) Revenue	4084	$ (497.75)
				Revenue from Services		$ (14,370,367.36)
	4210	$ (76,396.15)		Rent from Electric Property	4210	$ (76,396.15)
	4225	$ (319,382.76)		Late Payment Charges	4225	$ (319,382.76)
	4235	$ (122,565.48)		Miscellaneous Service Revenues	4235	$ (122,565.48)
				Other Operating Revenues		$ (518,344.39)
	4324	$ 0.11		Special Purpose Charge Recovery	4324	$ 0.11
	4325	$ (19,646.07)		Revenues from Merchandising, Jobbing, Etc.	4325	$ (19,646.07)
	4355	$ (114,494.98)		Gain on Disposition of Utility and Other Property	4355	$ (114,494.98)
	4360	$ 1,959.02		Loss on Disposition of Utility and Other Property	4360	$ 1,959.02
	4375	$ (403,902.13)		Revenues from Non-Utility Operations	4375	$ (403,902.13)
	4380	$ 3,944.22		Expenses of Non-Utility Operations	4380	$ 3,944.22
	4390	$ (154,276.69)		Miscellaneous Non-Operating Income	4390	$ (154,276.69)
				Other Income / Deductions		$ (686,416.52)
	4405	$ 13,042.06		Interest and Dividend Income	4405	$ 13,042.06
				Investment Income		
				Total Revenues		$ (55,457,626.62)
				Power Purchased	4705	$ 32,783,071.46
				Charges - WMS	4708	$ 2,073,929.97
				Charges - NW	4714	$ 2,703,950.60
				Charges - CN	4716	$ 2,252,196.15
				Charges - LV	4750	$ 82,392.23
				Other Power Supply Expenses		$ 39,895,540.41
			$ (15,562,086.21)			

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	Per Audited Financial Statements			Per Trial Balance (2.1.7)		
Expenses						
Distribution, operation and maintenance	5005	$ 630,949.29	$ 4,373,097.86	Operation Supervision and Engineering	5005	$ 630,949.29
	5012	$ 17,248.47		Distribution Station Equipment - Operation Supplies and Expenses	5017	$ 17,248.47
	5016	$ 15,682.52		Distribution Station Equipment - Operation Labour	5016	$ 15,682.52
	5020	$ 145,023.63		Overhead Distribution Lines and Feeders - Operation Labour	5020	$ 145,023.63
	5035	$ 264,367.63		Overhead Distribution Transformers - Operation	5035	$ 264,367.63
	5040	$ 90,536.37		Underground Distribution Lines and Feeders - Operation Labour	5040	$ 90,536.37
	5055	$ 43,361.32		Underground Distribution Transformers - Operation	5055	$ 43,361.32
	5065	$ 487,418.21		Meter Expense	5065	$ 487,418.21
	5070	$ 13,123.23		Customer Premises - Operation Labour	5070	$ 13,123.23
	5085	$ 350,018.22		Miscellaneous Distribution Expense	5085	$ 350,018.22
	5105	$ 125,696.86		Maintenance Supervision and Engineering	5105	$ 125,696.86
	5110	$ 7,233.79				
	5114	$ 23,702.91		Maintenance of Distribution Station Equipment	5114	$ 30,936.70
	5120	$ 417,704.54		Maintenance of Poles, Towers and Fixtures	5120	$ 417,704.54
	5125	$ 735,702.80		Maintenance of Overhead Conductors and Devices	5125	$ 735,702.80
	5130	$ 156,072.89		Maintenance of Overhead Services	5130	$ 156,072.89
	5135	$ 302,523.04		Overhead Distribution Lines and Feeders - Right of Way	5135	$ 302,523.04
	5145	$ 22,822.60		Maintenance of Underground Conduit	5145	$ 22,822.60
	5150	$ 98,244.55		Maintenance of Underground Conductor and Devices	5150	$ 98,244.55
	5155	$ 130,587.57		Maintenance of Underground Services	5155	$ 130,587.57
	5160	$ 268,807.74		Maintenance of Line Transformers	5160	$ 268,807.74
	5175	$ 22,514.71		Maintenance of Meters	5175	$ 22,514.71
	5195	$ 3,754.97		Maintenance of Other Installations on Customer Premises	5195	$ 3,754.97
				Distribution Expenses		$ 4,373,097.86
Billing and collecting	5305	$ 150,888.25	$ 1,867,865.32	Supervision	5305	$ 150,888.25
	5310	$ 606,167.23		Meter Reading Expense	5310	$ 606,167.23
	5315	$ 733,133.76		Customer Billing	5315	$ 733,133.76
	5320	$ 248,697.99		Collecting	5320	$ 248,697.99
	5325	$ (0.19)		Collecting - Cash Over and Short	5325	$ (0.19)
	5335	$ 63,472.73		Bad Debt Expense	5335	$ 63,472.73
	5340	$ 147,429.91				
	5350	$ (81,924.36)		Miscellaneous Customer Accounts Expenses	5340	$ 65,505.55
				Billing Collecting		$ 1,867,865.32
Community Relations	5410	$ 43,987.21	$ 143,208.38	Community Relations - Sundry	5410	$ 43,987.21
	5415	$ 99,221.17		Energy Conservation	5415	$ 99,221.17
				Community Relations		$ 143,208.38
Directors	5605	$ 102,864.75	$ 102,864.75	Executive Salaries and Expenses	5605	$ 102,864.75
General Administration	5610	$ 709,368.93	$ 1,934,589.95	Management Salaries and Expenses	5610	$ 709,368.93
	5615	$ 555,459.96		General Administrative Salaries and Expenses	5615	$ 555,459.96
	5620	$ 121,890.31		Office Supplies and Expenses	5620	$ 121,890.31
	5630	$ 411,932.70		Outside Services Employed	5630	$ 411,932.70
	5635	$ 24,096.20		Property Insurance	5635	$ 24,096.20
	5655	$ 87,382.02		Regulatory Expenses	5655	$ 87,382.02
	5665	$ (39,569.92)		Miscellaneous General Expenses	5665	$ (39,569.92)
	5681	$ 330.30		Special Purpose Charge Expense	5681	$ 330.30
				Administration General Expenses		$ 1,973,755.25
	6205	$ 16,500.00				
	6105	$ 47,199.45				
			$ 8,421,626.26			
Amortization	5705	$ 3,310,439.59	$ 4,097,539.62	Amortization Expense - Property, Plant and Equipment	5705	$ 3,915,498.98
	5706	$ 766,322.77				
	5715	$ 20,777.26		Amortization of Intangibles and Other Electric Plant	5715	$ 20,777.26
Less: Amortization of contributions in aid of construction	5715	$ (161,263.38)	$ (161,263.38)			
			$ 3,936,276.24	*Amortization Expenses*		$ 3,936,276.24
			$ 12,357,902.50			
Income Before Interest and Income Taxes			$ (3,204,183.71)			
Interest Expense	6005	$ 485,724.78	$ 535,592.67	Interest on Long Term Debt	6005	$ 485,724.78
	6035	$ 49,867.89		Other Interest Expense	6035	$ 49,867.89
				Interest Expenses		$ 535,592.67
Income Before Taxes			$ (2,668,591.04)			
Income taxes						
Current	6110	$ 507,107.00	$ 507,107.00	Income Taxes	6110	$ 507,107.00
Future	6115	$ 179,738.00	$ 179,738.00	Provision for Future Income Taxes	6115	$ 179,738.00
				Taxes Other Than Income Taxes	6105	$ 47,199.45
			$ 686,845.00	*Taxes*		$ 734,044.45
				Donations - LEAP Funding	6205	$ 16,500.00
				Other Deductions		
Income Before Regulatory Adjustment			**$ (1,981,746.04)**			
Regulatory Adjustment - payment in lieu of taxes	6310	$ 1,724,427.45	$ 1,724,427.45	Extraordinary Deductions	6310	$ 1,724,427.45
- future tax impact of adjustment	6315	$ (524,267.00)	$ (524,267.00)	Income Taxes: Extraordinary Item	6315	$ (524,267.00)
			$ 1,200,160.45	*Extraordinary Items*		$ 1,200,160.45
				Total Expenses		$ 54,676,041.03
Net Income			**$ (781,585.59)**	*Profit / Loss*		$ (781,585.59)

ANNUAL REPORT – PARENT COMPANY

HCHI is a subsidiary of the parent company, Haldimand County Utilities Inc. ("HCUI") which is 100% owned by the Corporation of Haldimand County. The corporate relationship is provided in this Exhibit at Tab 5, Schedules 7, 8, and 9.

A copy of HCUI's 2012 Annual Report is included as Appendix E to this schedule.

MATERIALITY THRESHOLD

The Board's Filing Requirements suggest a default materiality threshold for rate base, capital expenditures, OM&A and other items, and that it be determined based on a distributor's Revenue Requirement. HCHI's distribution Revenue Requirement falls into the category of greater than $10 million and less than or equal to $200 million; resulting in HCHI's materiality threshold calculated as 0.5% of its distribution Revenue Requirement. The calculation for the 2014 Test Year is summarized in Table 18 below.

Table 18
Materiality Threshold

	2014 Test Year
Distribution Revenue Requirement	12,874,552
	0.50%
Calculated Materiality Threshold	64,373
Materiality Threshold Used	**64,000**

ADMINISTRATION

OVERVIEW OF APPLICATION

In preparing this Application, HCHI has considered the impact on its customers, with the goal of minimizing those impacts. Customer bill impacts are set out in Tab 1, Schedule 10, Appendix A of this Exhibit and in Exhibit 8, Tab 4, Schedule 1. The monthly bill impact includes the effect of updated distribution rates, including the monthly service charge and volumetric rate, updated low voltage and retail transmission service rates, revised loss factors, the new REG Funding Adder, disposition of the DVAs and associated rate riders inclusive of the LRAMVA, disposition of the Stranded Meters and calculated rate rider, and the new rate rider for account 1576, Accounting Changes under CGAAP.

The proposed distribution rates and other charges are just and reasonable on the following grounds:

1. The proposed rates for the distribution of electricity have been prepared in accordance with the Filing Requirements and reflect traditional rate making and cost of service principles;

2. The proposed rates are necessary to ensure the Applicant has sufficient funds to meet its capital expenditure obligations, fund OM&A costs, provide for a reasonable Market Based Rate of Return, and to meet the Applicant's Payments in Lieu of Taxes ("PILs") requirements;

3. There are no impacts to any of the customer rate classes at any of the tested consumption levels that are so significant as to warrant the deferral of any adjustments being requested by the Applicant or the implementation of any other mitigation measures;

4. The other specific service charges proposed by the Applicant are the same as those previously approved by the Board; and

5. Such other grounds as may be set out in the material accompanying this Application Summary.

The increase in rates is required in order that: (i) HCHI maintain its current capital investment levels in infrastructure to ensure a safe and reliable distribution system; (ii) manage human and financial resources at a level which will ensure regulatory compliance, Electrical Safety Authority compliance, promote conservation programs, and effectively support its customers' needs; (iii) ensure that the HCHI is able to accommodate new load and generation connections and that new assets related to the new development are included in its rate base; and (iv) earn a reasonable rate of return.

Proposed Effective Date of Rate Order

HCHI is requesting the Board make its Rate Order effective May 1, 2014 in accordance with the Filing Requirements. In the event that the Board is unable to issue its Final Rate Order for implementation by HCHI effective May 1, 2014, HCHI requests that the Board issue an Order authorizing its existing rates as interim effective May 1, 2014.

Form of Hearing Requested

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

Relief Sought

HCHI applies for an Order or Orders approving the proposed distribution rates and charges set out in Exhibit 8 to this Application and proposed rate riders / funding adders set out in Exhibit 9 to this Application as just and reasonable rates and charges pursuant to Section 78 of the OEB Act, to be effective May 1, 2014, or as soon as possible thereafter; and

The Applicant seeks approval of its 5 year DSP as part of this Application in accordance with its deemed Conditions of License. The Applicant's 5 year DSP has been prepared in accordance with the Board's DS Filing Requirements.

Contact Information

HALDIMAND COUNTY HYDRO INC.
1 Greendale Drive
Caledonia, ON
N3W 2J3

PRESIDENT & CHIEF EXECUTIVE OFFICER:

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The "Table of Contents" to this Application has been provided at the beginning of this Exhibit along with the "Certification of Evidence" and legal and consultant representation information.

SPECIFIC APPROVALS REQUESTED

In this proceeding, HCHI is requesting the following:

1. Approval to charge rates effective May 1, 2014 to recover a Service Revenue Requirement of $14,012,613 as set out in Exhibit 8, Tab 1, Schedule 1. The schedule of proposed rates is set out in Exhibit 8, Tab 2, Schedule 2, and Appendix D;

2. Approval of the proposed loss factors as set out in Exhibit 8, Tab 1, Schedule 4;

3. Approval to continue to charge Wholesale Market and Rural Rate Protection Charges, and the microFIT monthly service charge approved in the Board's Decision and Order in the matter of HCHI's 2013 Electricity Distribution Rates (EB-2012-0129);

4. Approval of the updated low voltage ("LV") charge rates as proposed and described in Exhibit 8, Tab 1, Schedule 3;

5. Approval of the proposed changes to the Retail Transmission Service Rates ("RTSRs"), including Network and Connection charges, as set out in Exhibit 8, Tab 1, Schedule 3, including the harmonization of the existing RTSR's for the General Service 50 to 4,999 kW customer class currently different for an interval and non-interval metered customer of that class;

6. Approval to continue the Specific Service Charges and Transformer Ownership Allowance approved in the Board's Decision and Order in the matter of HCHI's 2013 Electricity Distribution Rates (EB-2012-0129);

7. Approval of HCHI's approach to cost allocation, and the associated proposed adjustments to rates in aligning the revenue-to-cost ratios, as identified in Exhibit 7 with specific adjustments to rates effective May 1, 2014, as set out in Exhibit 8 Tab 1 Schedules 1 and 2;

8. Approval to dispose of specific Deferral and Variance Account ("DVA") principal balances as at December 31, 2012 with projected carrying charges to April 30, 2014, and the associated rate riders effective May 1, 2014 for recovery over a one-year period as set out in Exhibit 9, Tab 2, Schedules 3 and 4;

9. Approval of the forecast Renewable Energy Generation investments and the amount requested for provincial recovery from all of Ontario rate payers;

10. Approval of the forecast Renewable Energy Generation investments and the amount requested for direct benefit recovery from its own rate payers and for a utility specific Renewable Energy Generation Funding Adder effective May 1, 2014 as set out in Exhibit 9, Tab 5;

11. Approval of disposition of its stranded meters net book value as at December 31, 2013 net of any recovery and a Stranded Meter rate rider effective May 1, 2014 as set out in Exhibit 9, Tab 3;

12. Approval to dispose of Account 1576 – Accounting Changes under CGAAP and the associated rate riders calculated inclusive of a rate of return as set out in Exhibit 9, Tab 4, to be effective May 1, 2014;

13. Approval for the recovery of LRAM recorded in the LRAM Variance account included in the calculated DVA rate riders effective May 1, 2014 for recovery over a one-year period as set out in Exhibit 9, Tab 6;

14. Approval of the Distribution System Plan ("DSP") as set out in Exhibit 2; and

15. Approval to discontinue recording the incremental Input Tax Credit on non-pass through items that were previously subject to PST and become subject to HST as instructed to do so in the Board's Decision and Order in the matter of HCHI's 2010 COS rate application (EB-2009-0265).

STATEMENT OF PUBLICATION

HCHI's customers in its service territory and its Embedded Distributor – Hydro One Networks Inc. will be affected by this Application. HCHI will immediately arrange to have the Notice of Application published in the local newspapers upon receiving it and the Board's Letter of Direction. The newspaper publications where the Notice of Application will appear are as follows:

- The Haldimand Press; Paid Publication; Circulation – 2,860 per week
- The Sachem & Gazette; Non-paid Publication; Circulation – 21,000 per week

Interested parties can also view the Application on HCHI's website at www.haldimandcountyhydro.ca.

DISTRIBUTION SERVICE TERRITORY AND DISTRIBUTION SYSTEM

Distribution Service Territory

In accordance with HCHI's Electricity Distribution Licence (ED-2002-0539), the Distribution Service area is defined as "*The Corporation of Haldimand County as defined in the Town of Haldimand Act, 1999, excluding the consumer located at 2330 Regional Road 3*".

Haldimand County is located on the north shore of Lake Erie, situated between Norfolk County, Six Nations of the Grand River Territory, County of Brant, City of Hamilton, and Niagara Region.

The total service territory for HCHI is 1,252 square kilometres ("$km^{2)}$, consisting of rural area of 1,216 km^2 and six urban communities totalling an area of 36 km^2 including Caledonia, Cayuga, Dunnville, Hagersville, Jarvis, and Townsend. The population density of Haldimand County is 35.9 persons per square km based on the County's area, including 19,108 private dwellings, as indicated in the 2011 Census. The service area population is represented by the municipal population of 44,876 as indicated in the 2011 Census.

A map of the HCHI's Distribution Service Territory accompanies this Schedule as Appendix F.

Distribution System

HCHI owns and operates the electricity distribution system in its licensed service area in Haldimand County, serving approximately 21,265 Residential, General Service, Street Lighting, Sentinel Lighting and Unmetered Scattered Load customers and one Embedded Distributor, as at September 30, 2013.

HCHI is supplied through the Hydro One Networks Inc. ("HONI") transmission system from 3 transformer stations at a primary voltage of 27.6 kV. Electricity is then

distributed through HCHI's service area, over 96 road km of underground cable and 1,652 road km of overhead primary conductor. HONI also owns 87 road km of distribution line in Haldimand County that serves HCHI's customers. Primary voltage is stepped down through 5 HCHI-owned distribution stations and 2 HONI-owned distribution stations to service General Service and Residential customers. Voltage is stepped down from the 27.6 kV, 8.32 kV, and 4.16 kV primary feeders through approximately 7,259 HCHI-owned distribution transformers.

HCHI load peaks are as follows:

- 2012 Utility Winter Max Monthly Peak Load - 78,706 kW
- 2012 Utility Summer Max Monthly Peak Load - 97,028 kW

HCHI's service territory is bordered by HONI to the North and East of Haldimand County and by Norfolk Power Distribution Inc. to the West of Haldimand County.

A schematic diagram of HCHI's Distribution System accompanies this schedule as Appendix G.

LIST OF NEIGHBOURING UTILITIES

The following distributors are located adjacent to HCHI's service area:

1. Norfolk Power Distribution Inc.
2. Hydro One Networks Inc.
3. Niagara Peninsula Energy Inc.

EXPLANATION OF HOST AND EMBEDDED UTILITIES

HCHI is supplied electricity from HONI through three HONI-owned transformer stations ("TS"), or delivery points, that are registered in the Independent Electricity System Operator (" IESO")-controlled grid. The three transformer stations are Jarvis TS, Dunnville TS and Caledonia TS.

The following Table 19 illustrates the feeder ownership at the three HONI TS's that deliver power to customers in Haldimand County. The feeders connected to each of the transformer stations are of mixed ownership between HONI and HCHI.

Table 19
Ownership of Feeders at HONI Transformer Stations

TS Name	Feeder	Owner	Notes
Caledonia	27M3	HONI	HCHI/HONI Customers Connected
	27M4	HCHI	HCHI Customers
	27M5	HCHI	HCHI Customers
	27M6	HONI	HCHI/HONI Customers Connected
Jarvis	57M1	HCHI	HCHI and one HONI Customer
	57M2	HONI	HONI Only
	57M3	HONI	HCHI/HONI Customers Connected
	57M4	HCHI	HCHI Customers
	57M5	HCHI	HCHI Customers
	57M6	HCHI	HCHI Customers
Dunnville	31M1	HCHI	HCHI Customers
	31M2	HONI	HCHI/HONI Customers Connected

Each TS supplies electricity to customers that are not part of the HCHI service territory. The HONI feeders pass through HCHI territory and serve HONI customers outside of Haldimand County's boundaries.

These situations result in scenarios where HCHI is embedded to HONI, and HONI is embedded to HCHI. Both scenarios will be described in more detail.

HCHI as Host Distributor to HONI Scenarios

Scenario 1

HONI has a customer (i.e. Air Products) that resides within HCHI's service territory. HONI has requested a second connection or supply for this customer. This second connection is to the HCHI-owned 57M1 feeder connected to Jarvis TS. This connection point is metered with an IESO-registered wholesale meter because Air Products is a Market Participant.

Scenario 2

At Caledonia TS, HONI has de-registered the following meter points (i.e. primary metering units or "PMUs") from the IESO Wholesale Market:

- 3rd Line PMU
- 4th Line PMU
- 5th Line PMU
- Canadian Gypsum Company PMU
- 6th Line PMU
- Georgia Pacific PMU
- Greens Rd PMU

The electricity that flows through these meter points is settled using the HCHI retail billing process. Each of the HONI-owned feeders (i.e. the 27M3 and the 27M6 at the Caledonia TS) has a HCHI-owned Wholesale IESO-registered Feeder meter installation. HCHI pays all IESO commodity related charges. HONI is the IESO-transmission connected customer and pays to the IESO all transmission and network connection related charges.

A map depicting HONI Embedded to HCHI accompanies this Schedule as Appendix H.

HCHI as Embedded Distributor to HONI

At Jarvis TS, Caledonia TS and Dunnville TS, HONI and HCHI each own feeders. HCHI has load connected to the following HONI feeders:

- Jarvis 57M3
- Caledonia 27M3
- Caledonia 27M6
- Dunnville 31M2

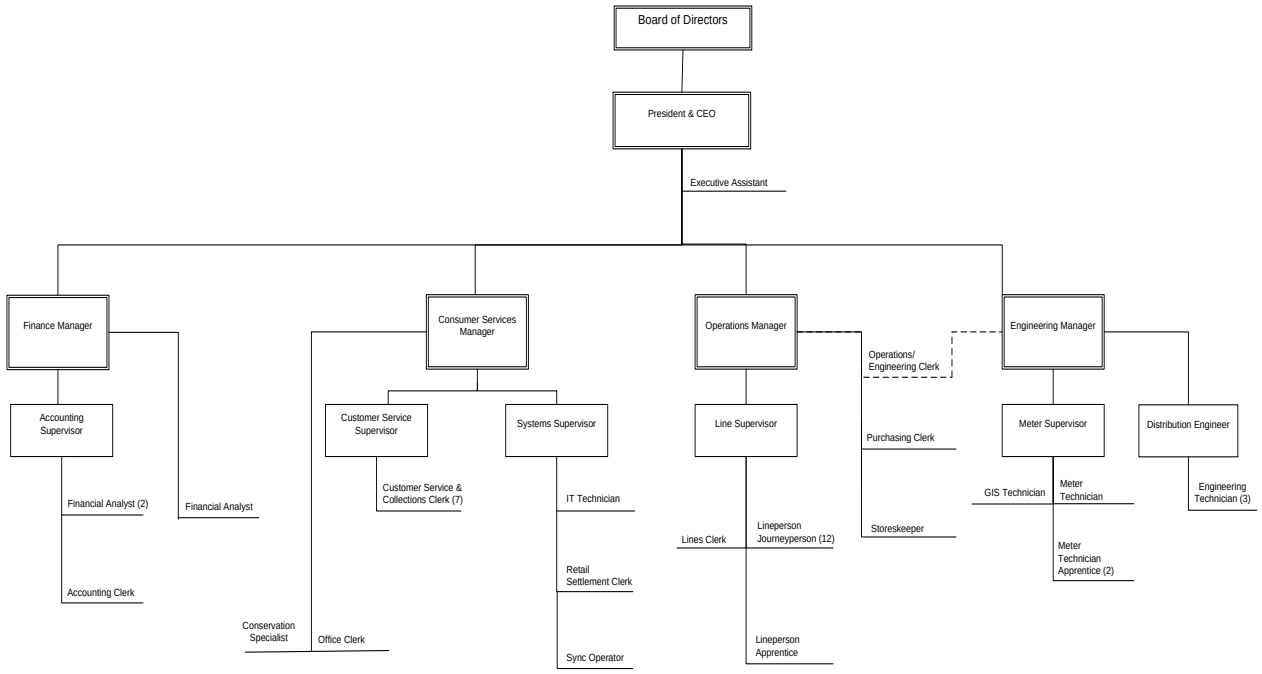
The Totalization Tables are set up to calculate the HCHI electricity that flows through these HONI feeders.

A map depicting HCHI Embedded to HONI accompanies this Schedule as Appendix I.

UTILITY ORGANIZATION STRUCTURE

The chart below depicts HCHI's existing organizational structure of 52 full-time positions. HCHI added an additional lineperson apprentice to this structure for the 2014 Test Year.

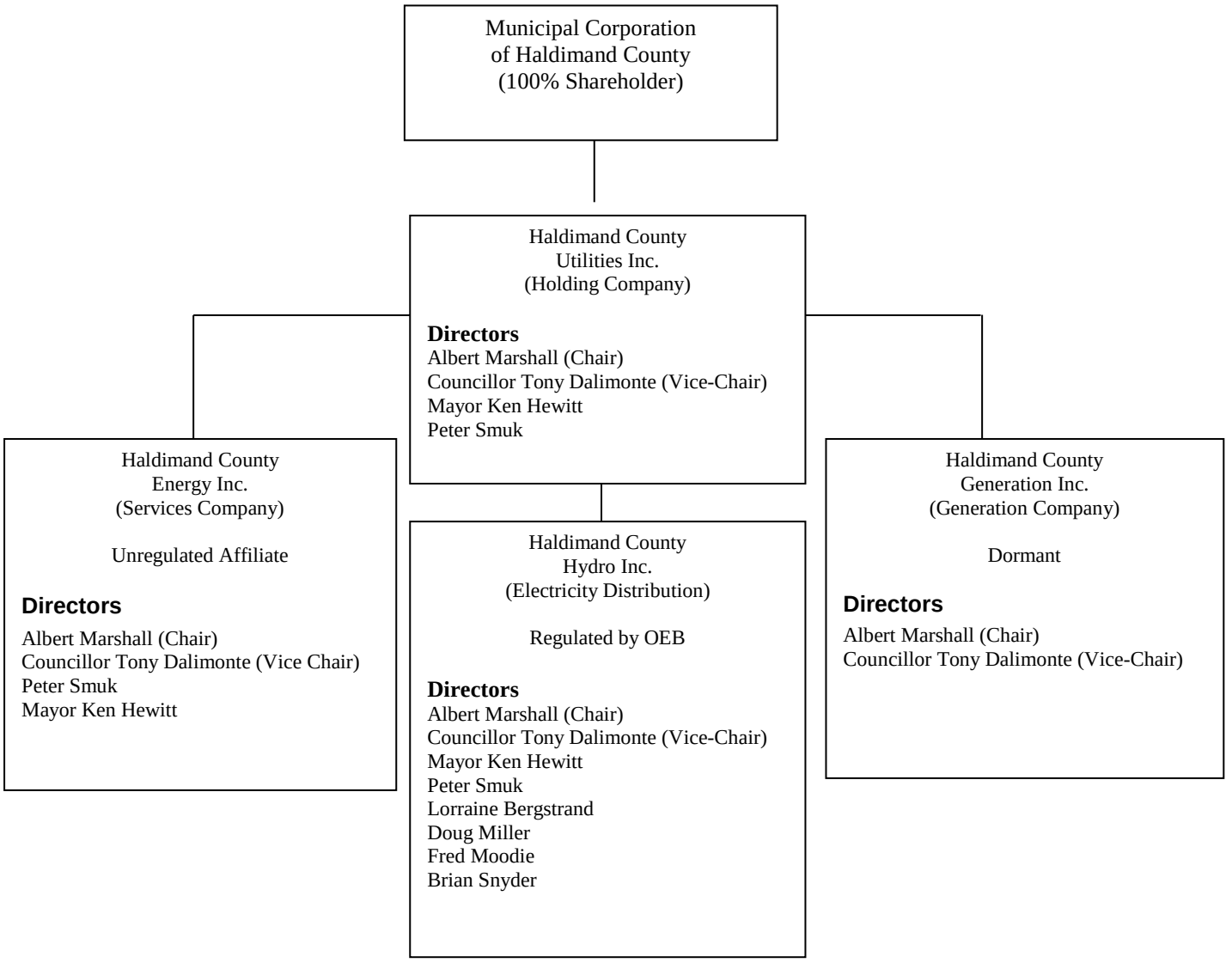
Organizational Structure



CORPORATE ENTITIES RELATIONSHIP CHART

HCHI is a wholly-owned subsidiary of Haldimand County Utilities Inc. which is 100% owned by the municipal Corporation of Haldimand County. A chart depicting HCHI's corporate structure is provided below:

Corporate Structure



Haldimand County Utilities Inc.

Haldimand County Utilities Inc. is a wholly-owned corporation of the municipal Corporation of Haldimand County and was incorporated October 13, 2000 under the laws of the Province of Ontario. The principal activity of the Company is to act as a Holding Company for the Distribution, Services, and Generation Companies.

Haldimand County Hydro Inc.

Haldimand County Hydro Inc. is a wholly owned subsidiary of Haldimand County Utilities Inc. and was incorporated October 13, 2000 under the laws of the Province of Ontario. The principle activity of the Company is to provide electrical power distribution throughout the Municipality of Haldimand County.

Haldimand County Energy Inc.

Haldimand County Energy Inc. is wholly owned subsidiary of Haldimand County Utilities Inc. and was incorporated October 13, 2000 under the laws of the Province of Ontario. The principle activities of the Company are to provide sentinel light rentals, streetlight maintenance, and water and waste water billing and collecting services for the Corporation of Haldimand County.

Haldimand County Generation Inc.

Haldimand County Generation Inc. is wholly owned subsidiary of Haldimand County Utilities Inc. and was incorporated October 13, 2000 under the laws of the Province of Ontario. The principle activity of the Company is to develop generation projects. Currently, there is no activity in the Company.

PLANNED CHANGES IN CORPORATE AND ORGANIZATIONAL STRUCTURE

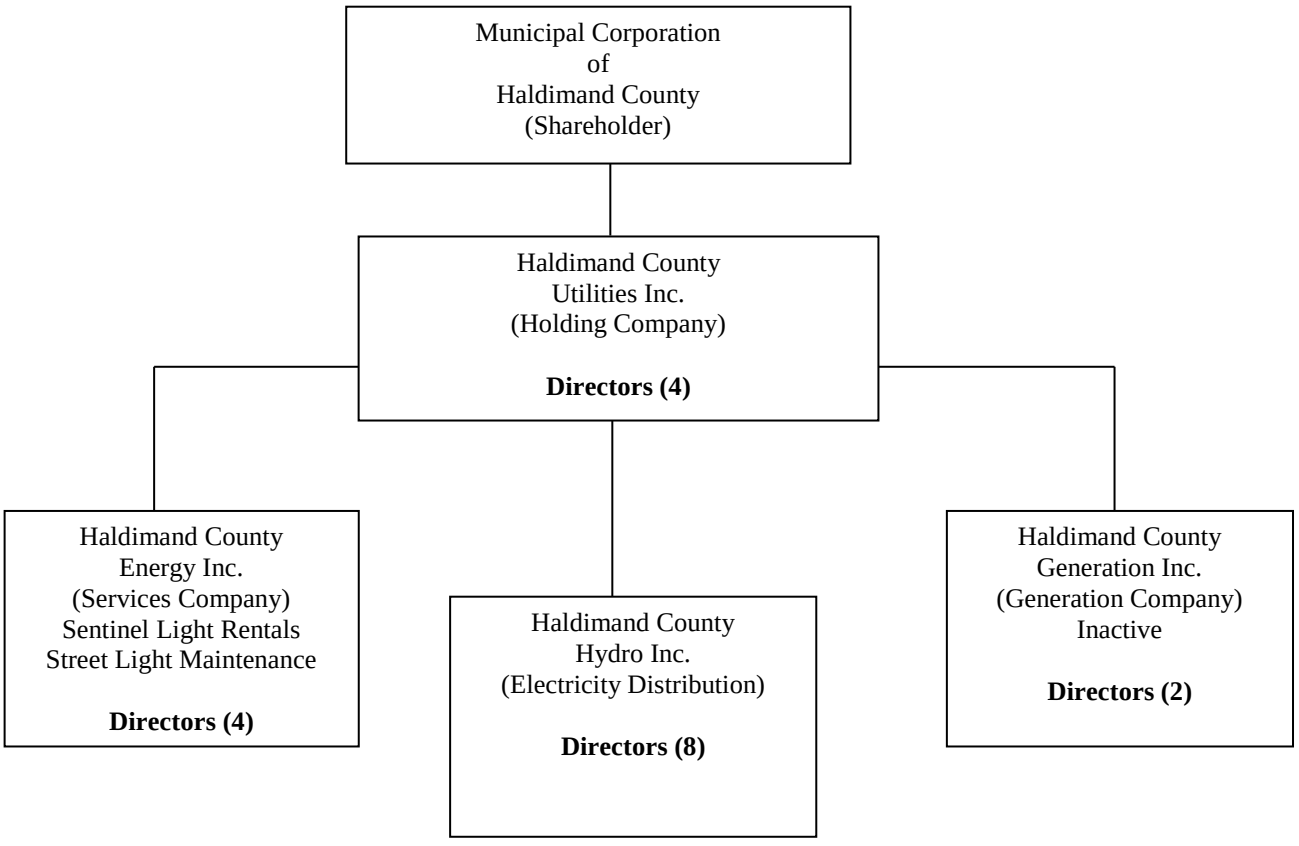
There are no changes planned to HCHI's corporate and organizational structures at the present time.

CORPORATE GOVERANCE

HCHI follows a formal process to manage business decisions and corporate direction. At the heart of process is the involvement of its Shareholder and Board Members.

The chart below depicts Haldimand County Utilities Inc.'s Corporate Structure, as of June 17, 2013, which notes the number of Board Members that reside on each of the Board of Directors:

Haldimand County Utilities Inc.
CORPORATE STRUCTURE
(June 17, 2013)



The Boards for Haldimand County Utilities Inc. and its subsidiary companies are formed to comply with Haldimand County Utilities Inc. *Shareholders Direction and Unanimous*

Shareholder Declaration which is consistent with the requirements of the Ontario Energy Board's Affiliate Relationships Code for Electricity Distributors and Transmitters, revised May 16, 2008,which includes under subsection *2.1.2 "A utility shall ensure that a least one-third of its Board of Directors is independent from any affiliate"*

Accordingly, Haldimand County Utilities Inc. *Shareholders Direction and Unanimous Shareholder Declaration* states:

"4.2 Board of Directors

The Corporation shall be managed by the Board, which shall consist of five (5) directors effective January 1, 2003 and shall consist of four (4) directors effective January 1, 2004, including as many as two designates from the Shareholder, who may be the Mayor or Councillors of the Shareholder, and the directors are to be appointed by the Shareholder. At least one-third of the directors of the Distribution Company are to be independent from the Corporation and the other Subsidiaries (for this purpose, independent means an individual who is not a councillor or employee of the Shareholder or an officer, director or employee of the Corporation or any of the other Subsidiaries).

4.3 Board of Directors of Subsidiaries

Subject to any matters requiring approval of the Shareholder pursuant to this Direction and Declaration and subject to matters to be approved by the Board of the Corporation pursuant to Section 4.1, the business and affairs of the Subsidiaries will be managed or supervised by their respective boards of directors. The Corporation will appoint the directors of the Subsidiaries. Subject to the requirement of Section 4.2, above, two (2) directors of the Distribution Corporation shall be the Mayor and/or Councilors of the Shareholder. Prior to the appointment of Subsidiary directors, the Shareholder shall be provided with

copies of applications for appointments to the Subsidiary Boards and be given the opportunity to provide input into the selection process."

As of August 12, 2013, the Board for Haldimand County Utilities Inc. and its subsidiary companies are comprised as follows:

Haldimand County Utilities Inc. (Holding)	**Haldimand County Hydro Inc. (Distribution)**	**Haldimand County Energy Inc. (Services)**	**Haldimand County Generation Inc. (Generation)**
Director A (06/15) Director B (06/14) Mayor Councillor	Director A (06/15) Director C (06/15) (I) Director D (06/14) (I) Director E (06/14) (I) Director B (06/14) Director F (06/15) (I) Mayor Councillor	Director A (06/15) Director B (06/14) Mayor Councillor	Director A (06/15) Councillor
		(Date of expiry of term – month/year) (I) – Independent Directors	

The Board of Directors for Haldimand County Utilities Inc. and its subsidiary companies schedule separate meetings in order to exercise independent judgment and responsibilities are delegated in accordance with the business of the Corporation as stipulated in Haldimand County Utilities Inc. *Shareholders Direction and Unanimous Shareholder Declaration.*

The Board of Directors mandate for Haldimand County Utilities Inc. and its subsidiary companies is formally outlined in the May 12, 2008 Haldimand County Utilities *Shareholders Direction and Unanimous Shareholder Declaration* and the 2006 Strategic Plan for the Corporation.

The Board's primary mandate is to meet and exceed the expectations of its Shareholder and align its principles with its Shareholder as outlined in Haldimand County Utilities Inc. *Shareholders Direction and Unanimous Shareholder Declaration*.

Accordingly, Haldimand County Utilities Inc. *Shareholders Direction and Unanimous Shareholder Declaration* states:

"2.3 Principles

The following principles will govern the operations of the Corporations:

(a) The Business is integral to the well-being and the infrastructure of Haldimand County. The Corporation recognizes that it is in the best interests of the Corporations and the community of stakeholders whom the Business affects that the Corporations conduct its affairs:

(i) on a commercially prudent basis;

(ii) in a manner consistent with the energy policies as may be established by the Shareholder from time to time;

(iii) on a for-profit basis and in accordance with the financial performance objectives of the Shareholder as set out herein.

(b) The Distribution Company will provide, a reliable, effective and efficient electricity distribution system.

(c) Distribution rates applicable to customers of the Distribution Company will be approved by the Board to be fair to all classes of customers and to achieve the returns permitted by the Ontario Energy Board.

(d) The Business is at all times subject to such licences, codes, policies, rules, orders, interim orders, approvals, consents and other actions of any Regulator.

(e) The Distribution Company will provide its services with an emphasis on customer satisfaction, addressing the customer service indicators and service reliability indicators accepted from time to time by the Ontario Energy Board.

(f) The Corporations will operate in a safe and environmentally responsible manner.

(g) The Distribution Company will promote energy conservation and environmental responsibility.

(h) The Board is responsible for determining and implementing the appropriate balance among the foregoing principles and for causing the Corporations to conduct its affairs in accordance with the same."

Accordingly, Haldimand County Utilities Inc. 2006 Strategic Plan states:

"HCUI's vision is:

To become recognized as a leading participant in the electricity distribution and related business sector in Ontario known particularly for high quality service, resilience and adaptability and continuous improvement and efficiency.

Its mission is:

To provide efficient, reliable and safe electricity distribution and other related services to customers and to contribute to the development of our jurisdiction's economy and our employees and the protection of the environment while enhancing the value of Haldimand County Utilities Inc."

The Board of Directors for Haldimand County Utilities Inc. and Haldimand County Hydro Inc. are scheduled to meet on a monthly basis as a minimum. Haldimand County

Energy Inc. and Haldimand County Generation Inc. meet as required. No change in meeting frequency is anticipated in the near term.

By-law No.1, a by-law relating generally to the transaction of the business and affairs of Haldimand County Utilities Inc. includes:

"*4.2* ***Calling of Meetings****. The Board may appoint a day or days in any month or months for regular meetings at a place and hour to be named.*

(a) Regular meetings of the Board shall be held at least once per quarter in the calendar year.

(b) Regular meetings of the Board shall be held on the dates prescribed by the CEO as directed by the Board.

(c) The Board may, by resolution, alter the date and/or time of a regular meeting."

-and-

"*4.3* ***Notice****. Subject as hereinafter provided, notice of every meeting of the Board shall be given to each Director at least 48 hours prior to the meeting. Notwithstanding the foregoing:*

(b) A copy of any resolution by the Board fixing the time and place of regular meetings of the Board shall be sent to each Director forthwith after being passed, but no other notice shall be required for any such regular meeting. The accidental failure to give notice of a meeting of the Board to a Director or any error in such notice not affecting the substance thereof shall not invalidate any action taken at the meeting."

The Board of Directors for Haldimand County Utilities Inc. passed by resolution that their regular meetings shall be held at 5:00 p.m. on the fourth Wednesday of every month at 1 Greendale Drive, Caledonia, ON.

Similar, the Board of Directors for Haldimand County Hydro Inc. passed by resolution that their regular be held at 6:00 p.m. on the fourth Wednesday of every month at 1 Greendale Drive, Caledonia, ON.

The meetings of the Board of Directors for Haldimand County Energy Inc. are scheduled on an "as required" basis but have consistently been held in March/April of each year for review and approval of financial statements for the prior year.

There have been no meetings scheduled for the Board of Directors of Haldimand County Generation Inc. as a result of no business activity in this Corporation to date.

Maintaining abreast of ongoing matters within the electrical industry does require ongoing exposure. The Board Members maintain their skill and knowledge through comprehensive monthly meetings with Senior Management, remaining active in industry events and participating in customer events hosted by Haldimand County Hydro Inc.

A policy entitled "*Expense Reimbursement Policy – Board Members & Staff for Attendance at Conference, Seminars & Other Business Events*", issued May 25, 2005 and last revised January 1, 2013, provides for *"… each Board Member be allowed to attend two multi-day conferences up to 3 days in length and 3 single day seminar/workshops/events per year provided these have been appropriately budgeted.*"

All Board Members are made aware of upcoming events on an ongoing basis.

The Board of Directors for Haldimand County Utilities Inc. and its subsidiary companies adhere to a formal process detailed in the Haldimand County Utilities Inc. *Shareholders Direction and Unanimous Shareholder Declaration*, which includes the following:

"4.10 Conflict of Interest Policy

The directors and officers of the Corporation and the Subsidiaries will strictly abide by the requirements of the OBCA and the Corporation in respect of conflicts of interest, including any requirements in respect of disclosure and abstention from voting. A detailed conflict of interest policy will be established by the Corporation within six (6) months of the date hereof and will form a part of the Bylaws of the Corporation.

4.11 Confidentiality

The Shareholder and the directors and officers of the Corporation and the Subsidiaries (each a "Receiving Party") will ensure that no confidential information of the Shareholder or the Corporations is disclosed or otherwise made available to any person, except to the extent that:

(a) disclosure to a Receiving Party's employees or agents is necessary for the performance of any Receiving Party's duties and obligations under this Direction and Declaration;

(b) disclosure is required in the course of judicial proceedings or pursuant to law; or

(c) the confidential information becomes part of the public domain (other than through unauthorized disclosure by the Receiving Party).

A detailed confidentiality policy consistent with the practices of corporate governance will be established by the Corporation within six (6) months of the date hereof and will form a part of the Bylaws of the Corporation."

By-law No.1, a by-law relating generally to the transaction of the business and affairs of Haldimand County Utilities Inc. includes:

3. DIRECTORS AND OFFICERS

"3.1 ***Conflict of Interest.*** *The directors and officers of the Corporation will strictly abide by the requirements of the OBCA and the Corporation's Conflict of Interest Policy including any requirements in respect of disclosure and abstention from voting.*

3.2 ***Confidentiality.*** *The directors and officers of the Corporation (each a "Receiving Party") will abide by the Confidentiality Policy and ensure that no confidential information of the Shareholder or the Corporations is disclosed or otherwise made available to any person, except to the extent that:*

(a) disclosure to a Receiving Party's employees or agents is necessary for the performance of any Receiving Party's duties and obligations under this Direction and Declaration;

(b) disclosure is required in the course of judicial proceedings or pursuant to law; or

(c) the confidential information becomes part of the public domain (other than through unauthorized disclosure by the Receiving Party)."

The Board of Directors for Haldimand County Hydro Inc. considered a proposed Confidentiality Policy and Conflict of Interest Policy but to-date has not approved either policy. The Board of Directors for Haldimand County Utilities Inc. and its subsidiary companies comply with their obligations under the *Shareholders Direction and Unanimous Shareholder Declaration*, By-law No. 1, and the *Ontario Business Corporations Act* (the "OBCA"), and are aware of their responsibilities under section 134 of the OBCA which states:

"Standards of care, etc., of directors, etc.

134. *(1) Every director and officer of a corporation in exercising his or her powers and discharging his or her duties to the corporation shall,*

(a) act honestly and in good faith with a view to the best interests of the corporation; and

(b) exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. R.S.O. 1990, c. B.16, s. 134 (1); 2006, c. 34, Sched. B, s. 24.

Duty to comply with Act, etc.

(2) Every director and officer of a corporation shall comply with this Act, the regulations, articles, by-laws and any unanimous shareholder agreement. R.S.O. 1990, c. B.16, s. 134 (2).

Cannot contract out of liability

(3) Subject to subsection 108 (5), no provision in a contract, the articles, the by-laws or a resolution relieves a director or officer from the duty to act in accordance with this Act and the regulations or relieves him or her from liability for a breach thereof. R.S.O. 1990, c. B.16, s. 134 (3)."

All Boards and Committees for Haldimand County Utilities Inc. and its subsidiary companies monitor their compliance to ethical business conduct, including at the start of each meeting which includes "Disclosure of Pecuniary Interest" as the first item of business.

At its meeting held May 23, 2012, the Board for Haldimand County Utilities Inc. passed the following:

> *"WHEREAS the following resolution was approved at the Board meeting held February 23, 2005:*
>
> > *"THAT the Minutes of the Meetings of the Boards for Haldimand County Utilities Inc. and its subsidiary companies be forwarded to Haldimand County Council following their approval with deletions as necessary to ensure compliance with any applicable privacy legislation and marked "Confidential" to be considered in closed session."*
>
> *AND WHEREAS the Board and all of its subsidiary Boards have reasons to periodically sign Confidentiality Agreements with third parties in order to facilitate investigation of business opportunities.*
>
> *AND WHEREAS Confidentiality Agreements typically impose restrictions on the distribution of confidential information, or even the existence of such an agreement, and provide penalties for violation.*
>
> *THEREFORE BE IT RESOLVED THAT resolution number 2 approved on February 23, 2005 be amended to read as follows:*
>
> > *THAT the Minutes of the Meetings of the Boards for Haldimand County Utilities Inc. and its subsidiary companies be forwarded to Haldimand County Council following their approval with deletions as necessary to ensure compliance with any applicable privacy legislation or Confidentiality Agreement with a third party and marked "Confidential" to be considered in closed session."*

The Nomination of Directors takes place to coincide with either end of term or resignation of a Director.

Prior to expiry of a Director's term, the Board for Haldimand County Utilities Inc. activates the Nominating Committee to deal with replacement or reappointment of the Director.

The Nominating Committee includes the Board of Directors for Haldimand County Utilities Inc. with the exception of any directors with an upcoming term expiring.

The Board of Directors for Haldimand County Utilities passed the following motion on October 23, 2002:

> *"THAT, the Nominating Committee use a consistent process of publicly advertising for potential candidates at the expiry of any Director's term of office for the holding company and its subsidiaries."*

Accordingly, a public advertisement for Board Member(s) required for Haldimand County Utilities Inc. or its subsidiary companies is placed in the local newspapers and on Haldimand County Hydro Inc.'s website.

All applications received are distributed to members of the Nominating Committee and candidates for interview are selected amongst the applications. Qualifications of Directors are considered in accordance with Section 4.4 of Haldimand County Utilities Inc. *Shareholders Direction and Unanimous Shareholder Declaration*, which includes:

> ***"4.4 Qualifications of Directors***
>
> *The Board and the board of directors of each Subsidiary will be residents of Canada. In appointing directors to the Board the Shareholder will give due regard to the qualifications of candidates, including experience or knowledge with respect to:*
>
> *(a) public utility commissions or boards of major corporations or other commercial enterprises;*
>
> *(b) corporate finance and financial services;*

(c) corporate governance;

(d) market development;

(e) large system operation and management;

(f) urban energy industries;

(g) information services;

(h) engineering;

(g) public policy issues and laws relating to the Corporations and the electricity industry; and

(i) environmental matters, labour relations and occupational health and safety issues.

Preference will be given to candidates for the Board who are residents and/or taxpayers of Haldimand County."

The Nominating Committee conducts the interviews of the selected candidates. A less detailed interview process is established for current Board Members but provides the opportunity for the current Board Members with term expiring to update qualifications, experience, and knowledge and disclose any reason that would restrict him/her from serving on the Board of Directors for Haldimand County Utilities Inc. or one of its subsidiary companies.

The Nominating Committee identifies, evaluates and recommends Board Member candidates to the Board of Directors for Haldimand County Utilities Inc. and the Shareholder in accordance with Haldimand County Utilities Inc. *Shareholders Direction and Unanimous Shareholder Declaration*, and in particular Sections 4.2 and 4.3 as described above.

The Board of Directors for Haldimand County Utilities Inc. and its subsidiary companies do form Committees as required to deal with specialized requirements.

Haldimand County Utilities Inc. *Shareholders Direction and Unanimous Shareholder Declaration* states:

> *"**4.9 Committees***
>
> *The Board may establish committees of the Board in the Board's discretion. It is anticipated that the Board may establish the following committees:*
>
> *(a) Audit and Finance Committee to review the financial results of the Corporation and the Subsidiaries;*
>
> *(b) Compensation Committee to determine senior management and directors' compensation."*
>
> *Notwithstanding the above, the Board will endeavour to use Committees prudently and not to delegate to committee's functions that should property be handled by the Board in full.*

In addition, the Board of Directors for Haldimand County Utilities Inc. establishes a Nominating Committee to identify, evaluate and recommend Board Member candidates to the Board for Haldimand County Utilities Inc. and the Shareholder as well as other Committees on an "as required" basis.

The Audit and Finance Committee is comprised of the Board of Directors for Haldimand County Utilities Inc. The Audit and Finance Committee reviews the audited financial statements of the Boards of Directors for Haldimand County Utilities Inc. and its subsidiaries with an external auditor and recommends approval to the respective Boards of Directors. The Audit and Finance Committee includes independent members and deals with matters within their scope of knowledge. Questions or concerns are referred to internal or external experts to form part of the decision making process as deemed required.

CHANGE IN TAX STATUS

HCHI is a corporation incorporated pursuant to the OBCA with its head office in Caledonia, ON. HCHI has not had a change in tax status since its last COS application.

PROCEDURAL ORDERS / MOTIONS / NOTICES

By letter dated December 11, 2012 the Board issued its list of distributors that are scheduled to apply to have their rates rebased for 2014 under the Fourth Generation Incentive Regulation regime for rates effective May 1, 2014. HCHI is one of the twenty distributors listed in Appendix A to that letter.

ACCOUNTING ORDERS REQUESTED

HCHI has no existing Accounting Orders and is not requesting any new Accounting Orders in this 2014 COS rate application proceeding.

COMPLIANCE WITH UNIFORM SYSTEM OF ACCOUNTS AND FILING REQUIREMENTS

Uniform System of Accounts

HCHI has followed the accounting principles and main categories of accounts as stated in the Board's *Accounting Procedures Handbook* (the "APH") and the *Uniform System of Accounts* ("USoA") contained therein, issued January 1, 2012 in the preparation of this Application.

Filing Requirements

HCHI has followed Chapter 2 and Chapter 5 of the Board's *Filing Requirements for Electricity Distribution Rate Applications* updated July 17, 2013 in order to prepare this Application.

ACCOUNTING STANDARDS FOR REGULATORY AND FINANCIAL REPORTING

In accordance with the Board's letter issued July 17, 2012 entitled *"Regulatory Accounting Policy Direction Regarding Changes to Depreciation and Capitalization Policies in 2012 and 2013"*, this Application has been prepared using Canadian Generally Accepted Accounting Principles ("CGAAP"), modified with the new depreciation rates ("new CGAAP"). In accordance with the Filing Requirements, HCHI has provided information for the historic years including 2010 Actual, 2011 Actual, and 2012 Actual in CGAAP, the 2013 Bridge Year in CGAAP and new CGAAP and the 2014 Test Year in new CGAAP.

The change in depreciation rates has impacted the calculation of the net book value of capital assets and depreciation expense. These changes have impacted the 2014 rate base and the 2014 distribution Revenue Requirement. HCHI has provided detailed explanation of this change in the applicable sections of this Application and filed OEB Appendix 2-YB "CGAAP Summary Impacts".

CHANGES IN ACCOUNTING METHODOLOGY

HCHI has not made any changes to the methodologies used in previous applications. In its Application, HCHI has, however, amended its depreciation rates effective January 1, 2013.

On July 17, 2012, the Board issued a letter entitled *"Regulatory Accounting Policy Direction Regarding Changes to Depreciation and Capitalization Policies in 2012 and 2013"*. In its letter, the Board provided direction on the option to defer the International Financial Reporting Standards ("IFRS") changeover in 2012. The Board advised distributors that changes to depreciation rates and capitalization policies that would have been implemented under IFRS could be made in 2012 under CGAAP and must be made no later than 2013 regardless of whether the Accounting Standards Board permits further deferrals beyond 2012 for the changeover to IFRS.

HCHI has elected to continue to prepare its financial statements under CGAAP, deferring its full IFRS implementation until January 1, 2015. In accordance with the Board's guidelines published July 17, 2012, HCHI has implemented the regulatory accounting change to its depreciation rates effective January 1, 2013. HCHI has no changes to implement with regards to capitalization policies.

HCHI allocated its Property, Plant, and Equipment ("PP&E") into components utilizing the Asset Depreciation Study prepared for the Board by Kinectrics Inc. and its own Asset Condition Assessment prepared by Kinectrics Inc. on HCHI's behalf. HCHI's PP&E components and revised estimated useful lives are as set out in Table 20.

HCHI reclassified its capital assets to the new PP&E components and applied the new useful lives effective January 1, 2013. The impact of the change to depreciation rates is a decrease in depreciation expense and accumulated depreciation of $1,459,184 in 2013 as compared to the previous depreciation expense under CGAAP prior to the useful lives regulatory accounting change.

Table 20
HCHI's Components and Useful Lives

Asset Type and APH Account	Prior Useful Life	Kinectrics Asset Depreciation Study			Adjusted Useful Life	
		Useful Life Min	Useful Life Typical	Useful Life Max		
Account 1820 - Distribution Station Equipment	30					
Substation Transformers		30	45	60	**45**	
Vacuum Station Breakers		35	45	65	**45**	
Account 1830 - Poles / Towers / Fixtures	25					
Concrete Poles		50	60	80	**60**	
Metal Poles		60	60	80	**60**	
Wood Poles		35	45	75	**50**	[1]
Account 1835 - Overhead Conductor & Devices	25					
Conductor		50	60	75	**50**	[2]
Gang-Operated Line Switches		30	45	55	**45**	
Reclosers		25	40	55	**40**	
Account 1840 - Underground Conduit	25					
U/G Conduit - Duct		30	50	85	**50**	
Account 1845 - Underground Conductor	25					
U/G XLPE Cable – Direct Buried (Non-Duct)		25	30	35	**30**	
U/G XLPE Cable – In Duct		35	40	55	**40**	
Pad-Mounted Switch Gear		20	30	45	**30**	
Account 1850 - Transformers	25					
Pole-Top		30	40	60	**40**	
Pad-Mount		25	40	45	**40**	
Step-Down(Rabbits)		30	40	60	**40**	
Account 1855 - Distribution Services	25					
O/H Conductor (Secondary)		50	60	75	**60**	
U/G Cable Direct Buried (Secondary)		25	35	40	**35**	
Account 1860 - Meters						
Primary Metering Units	25	15		30	**20**	
Smart Meters	15	5		15	**15**	
Interval Meters & Other Metering Equipment	25	25		50	**15**	[3]
General Plant						
Account 1908 - Buildings and Fixtures	50	50		75	**50**	
Account 1915 - Office Furniture and Equipment	10	5		15	**10**	
Account 1920 - Computer Hardware	5	3		5	**5**	
Account 1925 - Computer Software	5	2		5	**5**	
Account 1930 - Transportation Equipment - Buckets	8	5		15	**12**	
Account 1930 - Transportation Equipment - Pickups / Vans	8	5		10	**8**	
Account 1930 - Transportation Equipment - Trailers	8	5		20	**20**	
Account 1940 - Tools, Shop and Garage Equipment	10	5		10	**10**	
Account 1955 - Communication Equipment	5	2		10	**5**	

Notes:

1. HCHI experiences an average replacement on wood poles at 49 years. ACA report shows 20% failure rate at 45 years and 90% failure rate at 75 years. Assign a typical useful life of 50 years.
2. Overhead conductor is typically replaced at the same time as the wood pole and attracts the same typical useful life of 50 years.
3. Interval meters, CTs and PTs, and Meter Cabinets assigned the same typical useful life as the Smart Meter. Not part of the Kinectrics ACA report.

ACCOUNTING TREATMENT OF NON-UTILITY BUSINESS

HCHI is not currently engaged in renewable generation activities. HCHI is engaged in the delivery of the Ontario Power Authority's conservation and demand management programs. The accounting for these activities is segregated from HCHI's rate regulated activities in accordance with the Board's *Accounting Procedures Handbook for Electricity Distributors*.

STATUS OF BOARD DIRECTIVES FROM PREVIOUS BOARD DECISIONS

Directive from Smart Meter Cost Recovery Application (EB-2012-0272)

In its Decision and Order issued November 1, 2012 on HCHI's disposition of Smart Meter costs related to its Smart Meter deployment (EB-2012-0272), the Board agreed with HCHI's proposal to not dispose of its Stranded Meters at that time and directed HCHI to deal with the disposition in its next COS rate application. HCHI is requesting disposal of its Stranded Meters with this Application and calculated rate riders as set out in Exhibit 9, Tab 3.

HCHI does not have any other Board directives from previous Board decisions.

OTHER ITEMS

TRANSMISSION ASSETS

HCHI does not have any transmission assets.

CONDITIONS OF SERVICE

A copy of HCHI's latest (i.e. current) version of its Conditions of Service (Revision 4.1, dated July 10, 2006) was filed separately with the Board on August 14, 2006, and again to the Board's Compliance Office on June 13, 2007 as requested in accordance with their letter dated June 5, 2007.

HCHI's current Conditions of Service can be found on its website at www.haldimandcountyhydro.ca.

There are no changes contemplated to HCHI's Conditions of Service that would be required as a result of approval of this Application.

LETTERS OF COMMENT

HCHI will respond to any matters that are raised in letters of comment filed with the Board during the course of this proceeding and file those responses as additional evidence.

ONTARIO ENERGY BOARD 2014 COST OF SERVICE CHECKLIST

As set out in Chapter 1 of the Filing Requirements, the Board expects applications to be accurate, complete and internally consistent. If an application is incomplete or deficient then the Board may decline to process it until the deficiencies have been addressed.

The Board's "2014 COS Checklist" draws directly from the Board's Filing Requirements and has been developed as a tool to be used by the Board as part of its assessment as to whether or not an application is complete.

The checklist for 2014 COS filers was posted on the Board's website August 2, 2014. HCHI has used this checklist as a tool in preparation of its Application to ensure it has filed all information as per the Filing Requirements.

HCHI has attached a printed version of its 2014 checklist as Appendix J to this Exhibit and submitted an Excel version as part of the Application.

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Appendix 2-W
Bill Impacts

Customer Class: RESIDENTIAL (800 kWh)

TOU / non-TOU: TOU

Consumption 800 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 18.1700	1	$ 18.17	$ 18.8500	1	$ 18.85	$ 0.68	3.74%
Smart Meter Rate Adder	Monthly	$ 5.8900	1	$ 5.89		1	$ -	-$ 5.89	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0265	800	$ 21.20	$ 0.0275	800	$ 22.00	$ 0.80	3.77%
Smart Meter Disposition Rider			800	$ -		800	$ -	$ -	
LRAM & SSM Rate Rider			800	$ -		800	$ -	$ -	
Shared Tax Savings Rate Rider	per kWh	-$ 0.0003	800	-$ 0.24		800	$ -	$ 0.24	-100.00%
PILs a/c 1562 Disposition Rate Rider	per kWh	-$ 0.0018	800	-$ 1.44		800	$ -	$ 1.44	-100.00%
Stranded Meter Rate Rider	per kWh		800	$ -	$ 0.0021	800	$ 1.68	$ 1.68	
PPE Adjustment a/c 1576 Rate Rider	per kWh		800	$ -	-$ 0.0016	800	-$ 1.28	-$ 1.28	
REG Investment Rate Funding Adder	per kWh		800	$ -	$ 0.0002	800	$ 0.16	$ 0.16	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Sub-Total A (excluding pass through)				$ 43.58			$ 41.41	**-$ 2.17**	**-4.98%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0023	800	-$ 1.84	-$ 0.0014	800	-$ 1.12	$ 0.72	39.13%
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0004	800	$ 0.32	$ 0.0004	800	$ 0.32	$ -	0.00%
Line Losses on Cost of Power	per kWh	$ 0.0839	54.4	$ 4.57	$ 0.0839	53.04	$ 4.45	-$ 0.11	-2.50%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 47.42**			**$ 45.85**	**-$ 1.56**	**-3.30%**
RTSR - Network	per kWh	$ 0.0065	854	$ 5.55	$ 0.0065	853	$ 5.54	-$ 0.01	-0.16%
RTSR - Line and Transformation Connection	per kWh	$ 0.0048	854	$ 4.10	$ 0.0049	853	$ 4.18	$ 0.08	1.92%
Sub-Total C - Delivery (including Sub-Total B)				**$ 57.07**			**$ 55.58**	**-$ 1.49**	**-2.62%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	854	$ 3.76	$ 0.0044	853	$ 3.75	-$ 0.01	-0.16%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	854	$ 1.03	$ 0.0012	853	$ 1.02	-$ 0.00	-0.16%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	512	$ 34.30	$ 0.0670	512	$ 34.30	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	144	$ 14.98	$ 0.1040	144	$ 14.98	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	144	$ 17.86	$ 0.1240	144	$ 17.86	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 134.84**			**$ 133.34**	**-$ 1.50**	**-1.11%**
HST		13%		$ 17.53	13%		$ 17.33	-$ 0.20	-1.11%
Total Bill (including HST)				$ 152.37			$ 150.67	-$ 1.70	-1.11%
Ontario Clean Energy Benefit [1]				-$ 15.24			-$ 15.07	$ 0.17	-1.12%
Total Bill on TOU (including OCEB)				**$ 137.13**			**$ 135.60**	**-$ 1.53**	**-1.11%**
Loss Factor (%)		6.8000%			6.6300%				

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Appendix 2-W
Bill Impacts

Customer Class: GENERAL SERVICE LESS THAN 50 KW (2,000 kWh)

TOU / non-TOU: TOU

Consumption 2,000 **kWh** ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 29.0400	1	$ 29.04	$ 25.7700	1	$ 25.77	-$ 3.27	-11.26%
Smart Meter Rate Adder	Monthly	$ 9.1500	1	$ 9.15		1	$ -	-$ 9.15	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0205	2,000	$ 41.00	$ 0.0182	2,000	$ 36.40	-$ 4.60	-11.22%
Smart Meter Disposition Rider			2,000	$ -		2,000	$ -	$ -	
LRAM & SSM Rate Rider			2,000	$ -		2,000	$ -	$ -	
Shared Tax Savings Rate Rider	per kWh	-$ 0.0002	2,000	-$ 0.40		2,000	$ -	$ 0.40	-100.00%
PILs a/c 1562 Disposition Rate Rider	per kWh	-$ 0.0012	2,000	-$ 2.40		2,000	$ -	$ 2.40	-100.00%
Stranded Meter Rate Rider	per kWh		2,000	$ -	$ 0.0019	2,000	$ 3.80	$ 3.80	
PPE Adjustment a/c 1576 Rate Rider	per kWh		2,000	$ -	-$ 0.0010	2,000	-$ 2.00	-$ 2.00	
REG Investment Rate Funding Adder	per kWh		2,000	$ -	$ 0.0001	2,000	$ 0.20	$ 0.20	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 76.39			$ 64.17	**-$ 12.22**	**-16.00%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0023	2,000	-$ 4.60	-$ 0.0020	2,000	-$ 4.00	$ 0.60	13.04%
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0003	2,000	$ 0.60	$ 0.0004	2,000	$ 0.80	$ 0.20	33.33%
Line Losses on Cost of Power	per kWh	$ 0.0839	136.00	$ 11.41	$ 0.0839	132.60	$ 11.13	-$ 0.29	-2.50%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 84.59**			**$ 72.89**	**-$ 11.71**	**-13.84%**
RTSR - Network	per kWh	$ 0.0058	2136	$ 12.39	$ 0.0058	2133	$ 12.37	-$ 0.02	-0.16%
RTSR - Line and Transformation Connection	per kWh	$ 0.0044	2136	$ 9.40	$ 0.0045	2133	$ 9.60	$ 0.20	2.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 106.38**			**$ 94.85**	**-$ 11.53**	**-10.84%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2136	$ 9.40	$ 0.0044	2133	$ 9.38	-$ 0.01	-0.16%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	2136	$ 2.56	$ 0.0012	2133	$ 2.56	-$ 0.00	-0.16%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	1280	$ 85.76	$ 0.0670	1280	$ 85.76	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	360	$ 37.44	$ 0.1040	360	$ 37.44	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	360	$ 44.64	$ 0.1240	360	$ 44.64	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 300.43**			**$ 288.89**	**-$ 11.55**	**-3.84%**
HST		13%		$ 39.06	13%		$ 37.56	-$ 1.50	-3.84%
Total Bill (including HST)				$ 339.49			$ 326.44	-$ 13.05	-3.84%
Ontario Clean Energy Benefit [1]				-$ 33.95			-$ 32.64	$ 1.31	-3.86%
Total Bill on TOU (including OCEB)				**$ 305.54**			**$ 293.80**	**-$ 11.74**	**-3.84%**
Loss Factor (%)		6.8000%			6.6300%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

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Appendix 2-W
Bill Impacts

Customer Class: GENERAL SERVICE 50 TO 4,999 KW (50,000 kWh; 75 kW)

TOU / non-TOU: non-TOU

Consumption 50,000 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

75 kW

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 104.0600	1	$ 104.06	$ 84.9800	1	$ 84.98	-$ 19.08	-18.34%
Smart Meter Rate Adder	Monthly	$ 12.2400	1	$ 12.24		1	$ -	-$ 12.24	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 4.8286	75	$ 362.15	$ 3.9926	75	$ 299.45	-$ 62.70	-17.31%
Smart Meter Disposition Rider			75	$ -		75	$ -	$ -	
LRAM & SSM Rate Rider			75	$ -		75	$ -	$ -	
Shared Tax Savings Rate Rider	per kW	-$ 0.0271	75	-$ 2.03		75	$ -	$ 2.03	-100.00%
PILs a/c 1562 Disposition Rate Rider	per kW	-$ 0.1995	75	-$ 14.96		75	$ -	$ 14.96	-100.00%
Stranded Meter Rate Rider	per kW		75	$ -	$ 0.0571	75	$ 4.28	$ 4.28	
PPE Adjustment a/c 1576 Rate Rider	per kW		75	$ -	-$ 0.1257	75	-$ 9.43	-$ 9.43	
REG Investment Rate Funding Adder	per kW		75	$ -	$ 0.0188	75	$ 1.41	$ 1.41	
			75	$ -		75	$ -	$ -	
			75	$ -		75	$ -	$ -	
Sub-Total A (excluding pass through)				$ 461.45			$ 380.69	**-$ 80.76**	**-17.50%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 1.1866	75	-$ 89.00	$ 0.5185	75	$ 38.89	$ 127.88	143.70%
			75	$ -		75	$ -	$ -	
			75	$ -		75	$ -	$ -	
			75	$ -		75	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.1502	75	$ 11.27	$ 0.1439	75	$ 10.79	-$ 0.47	-4.19%
Line Losses on Cost of Power	per kWh	$ 0.0910	3,400.00	$ 309.40	$ 0.0910	3,315.00	$ 301.67	-$ 7.74	-2.50%
Smart Meter Entity Charge		$ 0.7900		$ -	$ 0.7900		$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 693.12**			**$ 732.04**	**$ 38.92**	**5.61%**
RTSR - Network	per kW	$ 2.3783	75	$ 178.37	$ 2.4800	75	$ 186.00	$ 7.63	4.28%
RTSR - Line and Transformation Connection	per kW	$ 1.7325	75	$ 129.94	$ 1.9031	75	$ 142.73	$ 12.80	9.85%
Sub-Total C - Delivery (including Sub-Total B)				**$ 1,001.43**			**$ 1,060.77**	**$ 59.34**	**5.93%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	53400	$ 234.96	$ 0.0044	53315	$ 234.59	-$ 0.37	-0.16%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	53400	$ 64.08	$ 0.0012	53315	$ 63.98	-$ 0.10	-0.16%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	50000	$ 350.00	$ 0.0070	50000	$ 350.00	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0780	600	$ 46.80	$ 0.0780	600	$ 46.80	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0910	49400	$ 4,495.40	$ 0.0910	49400	$ 4,495.40	$ -	0.00%
Total Bill on RPP (before Taxes)				**$ 6,192.92**			**$ 6,251.78**	**$ 58.86**	**0.95%**
HST		13%		$ 805.08	13%		$ 812.73	$ 7.65	0.95%
Total Bill (including HST)				$ 6,998.00			$ 7,064.51	$ 66.51	0.95%
Ontario Clean Energy Benefit [1]								$ -	
Total Bill on RPP (including OCEB)				**$ 6,998.00**			**$ 7,064.51**	**$ 66.51**	**0.95%**
Loss Factor (%)		6.8000%			6.6300%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

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Appendix 2-W
Bill Impacts

Customer Class: GENERAL SERVICE 50 TO 4,999 KW - "*Former*" INTERVAL METERED (500,000 kWh; 1,000 kW)

TOU / non-TOU: non-TOU

Consumption 500,000 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)
1,000 kW

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 104.0600	1	$ 104.06	$ 84.9800	1	$ 84.98	-$ 19.08	-18.34%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 4.8286	1,000	$ 4,828.60	$ 3.9926	1,000	$ 3,992.60	-$ 836.00	-17.31%
Smart Meter Disposition Rider			1,000	$ -		1,000	$ -	$ -	
LRAM & SSM Rate Rider			1,000	$ -		1,000	$ -	$ -	
Shared Tax Savings Rate Rider	per kW	-$ 0.0271	1,000	-$ 27.10		1,000	$ -	$ 27.10	-100.00%
PILs a/c 1562 Disposition Rate Rider	per kW	-$ 0.1995	1,000	-$ 199.50		1,000	$ -	$ 199.50	-100.00%
Stranded Meter Rate Rider	per kW		1,000	$ -	$ 0.0571	1,000	$ 57.10	$ 57.10	
PPE Adjustment a/c 1576 Rate Rider	per kW		1,000	$ -	-$ 0.1257	1,000	-$ 125.70	-$ 125.70	
REG Investment Rate Funding Adder	per kW		1,000	$ -	$ 0.0188	1,000	$ 18.80	$ 18.80	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 4,706.06			$ 4,027.78	**-$ 678.28**	**-14.41%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 1.1866	1,000	-$ 1,186.60	$ 0.5185	1,000	$ 518.50	$ 1,705.10	143.70%
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.1502	1,000	$ 150.20	$ 0.1439	1,000	$ 143.90	-$ 6.30	-4.19%
Line Losses on Cost of Power	per kWh	$ 0.0910	34,000	$ 3,094.00	$ 0.0910	33,150	$ 3,016.65	-$ 77.35	-2.50%
Smart Meter Entity Charge		$ 0.7900		$ -	$ 0.7900		$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 6,763.66**			**$ 7,706.83**	**$ 943.17**	**13.94%**
RTSR - Network	per kW	$ 2.5228	1000	$ 2,522.80	$ 2.4800	1000	$ 2,480.00	-$ 42.80	-1.70%
RTSR - Line and Transformation Connection	per kW	$ 1.9149	1000	$ 1,914.90	$ 1.9031	1000	$ 1,903.10	-$ 11.80	-0.62%
Sub-Total C - Delivery (including Sub-Total B)				**$ 11,201.36**			**$ 12,089.93**	**$ 888.57**	**7.93%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	534000	$ 2,349.60	$ 0.0044	533150	$ 2,345.86	-$ 3.74	-0.16%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	534000	$ 640.80	$ 0.0012	533150	$ 639.78	-$ 1.02	-0.16%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	500000	$ 3,500.00	$ 0.0070	500000	$ 3,500.00	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0780	600	$ 46.80	$ 0.0780	600	$ 46.80	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0910	499400	$ 45,445.40	$ 0.0910	499400	$ 45,445.40	$ -	0.00%
Total Bill on RPP (before Taxes)				**$ 63,184.21**			**$ 64,068.02**	**$ 883.81**	**1.40%**
HST		13%		$ 8,213.95	13%		$ 8,328.84	$ 114.90	1.40%
Total Bill (including HST)				$ 71,398.16			$ 72,396.86	$ 998.71	1.40%
Ontario Clean Energy Benefit [1]								$ -	
Total Bill on RPP (including OCEB)				**$ 71,398.16**			**$ 72,396.86**	**$ 998.71**	**1.40%**
Loss Factor (%)		6.8000%			6.6300%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

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Appendix 2-W
Bill Impacts

Customer Class: UNMETERED SCATTERED LOAD (500 kWh)

TOU / non-TOU: non-TOU

Consumption 500 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 20.8300	1	$ 20.83	$ 20.8700	1	$ 20.87	$ 0.04	0.19%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0027	500	$ 1.35	$ 0.0027	500	$ 1.35	$ -	0.00%
Smart Meter Disposition Rider			500	$ -		500	$ -	$ -	
LRAM & SSM Rate Rider			500	$ -		500	$ -	$ -	
Shared Tax Savings Rate Rider	per kWh	-$ 0.0002	500	-$ 0.10		500	$ -	$ 0.10	-100.00%
PILs a/c 1562 Disposition Rate Rider	per kWh	-$ 0.0016	500	-$ 0.80		500	$ -	$ 0.80	-100.00%
PPE Adjustment a/c 1576 Rate Rider	per kWh		500	$ -	-$ 0.0015	500	-$ 0.75	-$ 0.75	
REG Investment Rate Funding Adder	per kWh		500	$ -	$ 0.0002	500	$ 0.10	$ 0.10	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Sub-Total A (excluding pass through)				$ 21.28			$ 21.57	**$ 0.29**	**1.36%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0025	500	-$ 1.25	-$ 0.0003	500	-$ 0.15	$ 1.10	88.00%
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0003	500	$ 0.15	$ 0.0004	500	$ 0.20	$ 0.05	33.33%
Line Losses on Cost of Power	per kWh	$ 0.0780	34.00	$ 2.65	$ 0.0780	33.15	$ 2.59	-$ 0.07	-2.50%
Smart Meter Entity Charge		$ 0.7900		$ -	$ 0.7900		$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 22.83**			**$ 24.21**	**$ 1.37**	**6.02%**
RTSR - Network	per kWh	$ 0.0058	534	$ 3.10	$ 0.0058	533	$ 3.09	-$ 0.00	-0.16%
RTSR - Line and Transformation Connection	per kWh	$ 0.0044	534	$ 2.35	$ 0.0045	533	$ 2.40	$ 0.05	2.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 28.28**			**$ 29.70**	**$ 1.42**	**5.02%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	534	$ 2.35	$ 0.0044	533	$ 2.35	-$ 0.00	-0.16%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	534	$ 0.64	$ 0.0012	533	$ 0.64	-$ 0.00	-0.16%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	500	$ 3.50	$ 0.0070	500	$ 3.50	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0780	500	$ 39.00	$ 0.0780	500	$ 39.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0910	0	$ -	$ 0.0910	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 74.02**			**$ 75.43**	**$ 1.41**	**1.91%**
HST		13%		$ 9.62	13%		$ 9.81	$ 0.18	1.91%
Total Bill (including HST)				$ 83.64			$ 85.24	$ 1.60	1.91%
Ontario Clean Energy Benefit [1]				-$ 8.36			-$ 8.52	-$ 0.16	1.91%
Total Bill on TOU (including OCEB)				**$ 75.28**			**$ 76.72**	**$ 1.44**	**1.91%**
Loss Factor (%)		6.8000%			6.6300%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

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Appendix 2-W
Bill Impacts

Customer Class: SENTINEL LIGHTING (77 kWh; 0.21 kW)

TOU / non-TOU: non-TOU

Consumption 77 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

0.21 kW

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 12.9900	1	$ 12.99	$ 14.1400	1	$ 14.14	$ 1.15	8.85%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 33.5294	0.21	$ 7.04	$ 36.4943	0.21	$ 7.66	$ 0.62	8.84%
Smart Meter Disposition Rider			0.21	$ -		0.21	$ -	$ -	
LRAM & SSM Rate Rider			0.21	$ -		0.21	$ -	$ -	
Shared Tax Savings Rate Rider	per kW	-$ 0.5613	0.21	-$ 0.12		0.21	$ -	$ 0.12	-100.00%
PILs a/c 1562 Disposition Rate Rider	per kW	-$ 2.2663	0.21	-$ 0.48		0.21	$ -	$ 0.48	-100.00%
PPE Adjustment a/c 1576 Rate Rider	per kW		0.21	$ -	-$ 3.9156	0.21	-$ 0.82	-$ 0.82	
REG Investment Rate Funding Adder	per kW		0.21	$ -	$ 0.5553	0.21	$ 0.12	$ 0.12	
			0.21	$ -		0.21	$ -	$ -	
			0.21	$ -		0.21	$ -	$ -	
			0.21	$ -		0.21	$ -	$ -	
Sub-Total A (excluding pass through)				$ 19.44			$ 21.10	**$ 1.66**	**8.54%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 1.3863	0.21	-$ 0.29	$ 5.9957	0.21	$ 1.26	$ 1.55	532.50%
			0.21	$ -		0.21	$ -	$ -	
			0.21	$ -		0.21	$ -	$ -	
			0.21	$ -		0.21	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.1103	0.21	$ 0.02	$ 0.1210	0.21	$ 0.03	$ 0.00	9.70%
Line Losses on Cost of Power	per kWh	$ 0.0780	5.24	$ 0.41	$ 0.0780	5.11	$ 0.40	-$ 0.01	-2.50%
Smart Meter Entity Charge		$ 0.7900		$ -	$ 0.7900		$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 19.58**			**$ 22.78**	**$ 3.20**	**16.36%**
RTSR - Network	per kW	$ 1.8025	0.21	$ 0.38	$ 1.8003	0.21	$ 0.38	-$ 0.00	-0.12%
RTSR - Line and Transformation Connection	per kW	$ 1.3675	0.21	$ 0.29	$ 1.3957	0.21	$ 0.29	$ 0.01	2.06%
Sub-Total C - Delivery (including Sub-Total B)				**$ 20.24**			**$ 23.45**	**$ 3.21**	**15.85%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	82	$ 0.36	$ 0.0044	82	$ 0.36	-$ 0.00	-0.16%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	82	$ 0.10	$ 0.0012	82	$ 0.10	-$ 0.00	-0.16%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	77	$ 0.54	$ 0.0070	77	$ 0.54	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0780	77	$ 6.01	$ 0.0780	77	$ 6.01	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0910	0	$ -	$ 0.0910	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 27.50**			**$ 30.71**	**$ 3.21**	**11.66%**
HST		13%		$ 3.57	13%		$ 3.99	$ 0.42	11.66%
Total Bill (including HST)				$ 31.07			$ 34.70	$ 3.62	11.66%
Ontario Clean Energy Benefit [1]				-$ 3.11			-$ 3.47	-$ 0.36	11.58%
Total Bill on TOU (including OCEB)				**$ 27.96**			**$ 31.23**	**$ 3.26**	**11.67%**
Loss Factor (%)		6.8000%			6.6300%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

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Appendix 2-W
Bill Impacts

Customer Class: STREET LIGHTING (170,000 kWh; 550 kW)

TOU / non-TOU: non-TOU

Consumption 170,000 kWh ○ May 1 - October 31 ◉ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

550.00 kW

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 6.0900	2973	$ 18,105.57	$ 6.1000	2973	$ 18,135.30	$ 29.73	0.16%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 15.5853	550.00	$ 8,571.92	$ 15.6168	550.00	$ 8,589.24	$ 17.32	0.20%
Smart Meter Disposition Rider			550.00	$ -		550.00	$ -	$ -	
LRAM & SSM Rate Rider			550.00	$ -		550.00	$ -	$ -	
Shared Tax Savings Rate Rider	per kW	-$ 0.2405	550.00	-$ 132.28		550.00	$ -	$ 132.28	-100.00%
PILs a/c 1562 Disposition Rate Rider	per kW	-$ 1.0803	550.00	-$ 594.17		550.00	$ -	$ 594.17	-100.00%
PPE Adjustment a/c 1576 Rate Rider	per kW		550.00	$ -	-$ 1.4566	550.00	-$ 801.13	-$ 801.13	
REG Investment Rate Funding Adder	per kW		550.00	$ -	$ 0.2194	550.00	$ 120.67	$ 120.67	
			550.00	$ -		550.00	$ -	$ -	
			550.00	$ -		550.00	$ -	$ -	
			550.00	$ -		550.00	$ -	$ -	
Sub-Total A (excluding pass through)				$ 25,951.05			$ 26,044.08	**$ 93.03**	**0.36%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 1.6598	550.00	-$ 912.89	-$ 0.0569	550.00	-$ 31.30	$ 881.60	96.57%
			550.00	$ -		550.00	$ -	$ -	
			550.00	$ -		550.00	$ -	$ -	
			550.00	$ -		550.00	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.1081	550.00	$ 59.46	$ 0.1115	550.00	$ 61.33	$ 1.87	3.15%
Line Losses on Cost of Power	per kWh	$ 0.0910	11,560.00	$ 1,051.96	$ 0.0910	11,271.00	$ 1,025.66	-$ 26.30	-2.50%
Smart Meter Entity Charge		$ 0.7900		$ -	$ 0.7900		$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 26,149.57**			**$ 27,099.77**	**$ 950.20**	**3.63%**
RTSR - Network	per kW	$ 1.7934	550	$ 986.37	$ 1.7912	550	$ 985.16	-$ 1.21	-0.12%
RTSR - Line and Transformation Connection	per kW	$ 1.3395	550	$ 736.73	$ 1.3671	550	$ 751.91	$ 15.18	2.06%
Sub-Total C - Delivery (including Sub-Total B)				**$ 27,872.67**			**$ 28,836.84**	**$ 964.17**	**3.46%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	181560	$ 798.86	$ 0.0044	181271	$ 797.59	-$ 1.27	-0.16%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	181560	$ 217.87	$ 0.0012	181271	$ 217.53	-$ 0.35	-0.16%
Standard Supply Service Charge	Monthly	$ 0.2500	2973	$ 743.25	$ 0.2500	2973	$ 743.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	170000	$ 1,190.00	$ 0.0070	170000	$ 1,190.00	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0780	600	$ 46.80	$ 0.0780	600	$ 46.80	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0910	169400	$ 15,415.40	$ 0.0910	169400	$ 15,415.40	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 46,284.85**			**$ 47,247.40**	**$ 962.55**	**2.08%**
HST		13%		$ 6,017.03	13%		$ 6,142.16	$ 125.13	2.08%
Total Bill (including HST)				$ 52,301.88			$ 53,389.57	$ 1,087.68	2.08%
Ontario Clean Energy Benefit [1]								$ -	
Total Bill on TOU (including OCEB)				**$ 52,301.88**			**$ 53,389.57**	**$ 1,087.68**	**2.08%**
Loss Factor (%)		6.8000%			6.6300%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

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Appendix 2-W
Bill Impacts

Customer Class: EMBEDDED DISTRIBUTOR - HYDRO ONE NETWORKS INC.

TOU / non-TOU: non-TOU

Consumption 6,055,000 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

18,970.00 kW

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 184.3200	1	$ 184.32	$ 478.0400	1	$ 478.04	$ 293.72	159.35%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 0.5680	18,970.00	$ 10,774.96	$ 1.4731	18,970.00	$ 27,944.71	$ 17,169.75	159.35%
Smart Meter Disposition Rider			18,970.00	$ -		18,970.00	$ -	$ -	
LRAM & SSM Rate Rider			18,970.00	$ -		18,970.00	$ -	$ -	
			18,970.00	$ -		18,970.00	$ -	$ -	
			18,970.00	$ -		18,970.00	$ -	$ -	
			18,970.00	$ -		18,970.00	$ -	$ -	
			18,970.00	$ -		18,970.00	$ -	$ -	
			18,970.00	$ -		18,970.00	$ -	$ -	
			18,970.00	$ -		18,970.00	$ -	$ -	
			18,970.00	$ -		18,970.00	$ -	$ -	
Sub-Total A (excluding pass through)				$ 10,959.28			$ 28,422.75	**$ 17,463.47**	**159.35%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.5405	18,970.00	-$ 10,253.29	$ 0.5264	18,970.00	$ 9,985.81	$ 20,239.09	197.39%
			18,970.00	$ -		18,970.00	$ -	$ -	
			18,970.00	$ -		18,970.00	$ -	$ -	
			18,970.00	$ -		18,970.00	$ -	$ -	
Low Voltage Service Charge	per kW		18,970.00	$ -		18,970.00	$ -	$ -	
Line Losses on Cost of Power	per kWh	$ 0.0910	184,677.50	$ 16,805.65	$ 0.0910	174,384.00	$ 15,868.94	-$ 936.71	-5.57%
Smart Meter Entity Charge		$ 0.7900		$ -	$ 0.7900		$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 17,511.65**			**$ 54,277.50**	**$ 36,765.85**	**209.95%**
RTSR - Network	per kW	$ 2.5638	19549	$ 50,118.66	$ 2.8960	19516	$ 56,519.31	$ 6,400.65	12.77%
RTSR - Line and Transformation Connection	per kW	$ 2.3365	19549	$ 45,675.27	$ 2.3898	19516	$ 46,640.14	$ 964.87	2.11%
Sub-Total C - Delivery (including Sub-Total B)				##########			**$ 157,436.95**	**$ 44,131.37**	**38.95%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	6239678	$ 27,454.58	$ 0.0044	6229384	$ 27,409.29	-$ 45.29	-0.16%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	6239678	$ 7,487.61	$ 0.0012	6229384	$ 7,475.26	-$ 12.35	-0.16%
Standard Supply Service Charge	Monthly	$ 0.2500	2973	$ 743.25	$ 0.2500	2973	$ 743.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	6055000	$ 42,385.00	$ 0.0070	6055000	$ 42,385.00	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0780	600	$ 46.80	$ 0.0780	600	$ 46.80	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0910	6054400	##########	$ 0.0910	6054400	$ 550,950.40	$ -	0.00%
Total Bill on TOU (before Taxes)				##########			**$ 786,446.95**	**$ 44,073.73**	**5.94%**
HST		13%		$ 96,508.52	13%		$ 102,238.10	$ 5,729.58	5.94%
Total Bill (including HST)				##########			$ 888,685.05	$ 49,803.31	5.94%
Ontario Clean Energy Benefit [1]								$ -	
Total Bill on TOU (including OCEB)				##########			**$ 888,685.05**	**$ 49,803.31**	**5.94%**

Loss Factor (%) 3.0500% 2.8800%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

HALDIMAND COUNTY HYDRO INC.

FINANCIAL STATEMENTS

For the year ended December 31, 2010

Millard, Rouse & Rosebrugh LLP
Chartered Accountants

HALDIMAND COUNTY HYDRO INC.

For the year ended December 31, 2010

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Millard, Rouse & Rosebrugh LLP
Chartered Accountants
P.O. Box 57, 91 Main Street South
Hagersville, Ontario N0A 1H0
Telephone: (905) 768-5883
Facsimile: (905) 768-5843

INDEPENDENT AUDITORS' REPORT

To the Shareholder of
Haldimand County Hydro Inc.

We have audited the accompanying financial statements of Haldimand County Hydro Inc., which comprise the statement of financial position as at December 31, and the statements of income, retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

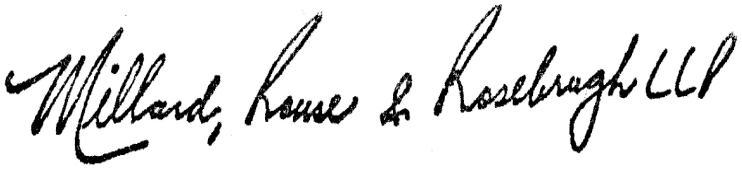
Management's Responsibility for the Financial Statements
Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility
Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgement, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the financial statements present fairly, in all material respects, the financial position of Haldimand County Hydro Inc. as at December 31, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.



March 23, 2011

CHARTERED ACCOUNTANTS
Licensed Public Accountants

HALDIMAND COUNTY HYDRO INC.

STATEMENT OF FINANCIAL POSITION

As at December 31	2010	2009
ASSETS		
Current Assets		
Cash and bank	2,494,213	7,513,910
Unbilled revenue	5,259,993	5,163,885
Accounts receivable	3,192,917	2,920,869
OPA conservation program	107,499	13,532
Inventory	1,113,623	843,516
Income taxes recoverable	33,073	-
Prepaid expenses	212,360	101,420
	12,413,678	16,557,132
Property, Plant and Equipment (Note 5)	37,843,168	37,236,507
Deferred Financing Costs	-	3,235
Regulatory Assets (Note 6)	2,576,731	3,043,000
Future Tax Asset	1,182,173	840,300
	54,015,750	57,680,174
LIABILITIES		
Current Liabilities		
Accounts payable and accrued expenses	7,051,105	7,671,043
Due to Haldimand County Energy Inc.	563,271	480,706
Due to Haldimand County Utilities Inc.	19,134	12,328
Income taxes payable	-	773,352
Deposit advance for recoverable work	-	2,561,017
Current portion of long term liabilities	1,555,851	8,359,998
	9,189,361	19,858,444
Long Term Liabilities (Note 7)	9,093,433	4,371,672
	18,282,794	24,230,116
Deferred Credits		
Contributions in aid of construction	3,786,815	3,456,315
Less: Amortization to date	691,355	546,789
	3,095,460	2,909,526
SHAREHOLDER'S EQUITY		
Capital (Note 8)	19,880,705	19,880,705
Retained Earnings (Page 3)	12,756,791	10,659,827
	32,637,496	30,540,532
	54,015,750	57,680,174

See accompanying notes

HALDIMAND COUNTY HYDRO INC.

STATEMENT OF RETAINED EARNINGS

For the year ended December 31	2010	2009
Retained Earnings - Beginning of Year	10,659,827	8,473,801
Net income	2,788,409	2,701,834
Dividends	(691,445)	(515,808)
Retained Earnings - End of Year	12,756,791	10,659,827

See accompanying notes

HALDIMAND COUNTY HYDRO INC.

STATEMENT OF INCOME

For the year ended December 31	2010	2009
Service Revenue		
Residential	10,311,194	9,051,719
General	8,941,377	11,043,121
Street lighting	160,799	141,953
Sentinel lighting	23,323	24,531
Embedded Distributor	5,530,280	1,621,481
Retailer	4,593,215	3,547,890
Retail transmission and low voltage	4,969,886	5,085,486
Regulatory	2,909,386	2,668,789
Distribution services	13,024,494	13,266,128
	50,463,954	46,451,098
Cost of Power	37,439,461	33,184,970
Gross Margin on Service Revenue	13,024,493	13,266,128
Other Operating Revenue (Note 9)	1,283,687	1,286,296
	14,308,180	14,552,424
Expenses		
Distribution, operation and maintenance (Note 10)	3,642,500	3,595,569
Community relations	42,643	35,182
Billing and collecting	1,305,989	1,375,730
General administration	1,854,560	1,989,697
Directors	48,832	68,408
	6,894,524	7,064,586
Amortization	2,973,032	2,807,879
Less: Amortization of contributions in aid of construction	144,566	119,593
	2,828,466	2,688,286
	9,722,990	9,752,872
Income Before Interest and Income Taxes	4,585,190	4,799,552
Interest expense	563,732	697,784
Income Before Income Taxes	4,021,458	4,101,768
Income taxes - current (Note 11)	1,574,922	1,519,769
- future	(341,873)	(119,835)
	1,233,049	1,399,934
Net Income	2,788,409	2,701,834

See accompanying notes

HALDIMAND COUNTY HYDRO INC.

STATEMENT OF CASH FLOWS

For the year ended December 31	2010	2009
Cash Flows from Operating Activities		
Net Income	2,788,409	2,701,834
Charges (credits) to income not involving cash		
Amortization	2,973,032	2,807,879
Amortization of contributions in aid of capital	(144,566)	(119,593)
(Gain) loss on disposal of property, plant and equipment	(5,519)	(9,479)
Future income taxes	(341,873)	(119,835)
	5,269,483	5,260,806
Net change in non-cash working capital balances related to operations	(4,741,179)	4,674,161
	528,304	9,934,967
Cash Flows from Financing Activities		
Dividends	(691,445)	(515,808)
Deposits from customers (net)	34,242	219,375
Contributions in aid of construction	330,500	779,896
Long term debt	(2,116,628)	810,728
Deferred financing costs	3,235	9,706
	(2,440,096)	1,303,897
Cash Flows from Investing Activities		
Purchase of property, plant and equipment	(3,587,264)	(4,968,845)
Proceeds on disposal of property, plant and equipment	13,090	17,483
Regulatory assets/liabilities	466,269	(2,314,930)
	(3,107,905)	(7,266,292)
Net Decrease in Cash and Cash Equivalents	(5,019,697)	3,972,572
Opening Cash and Cash Equivalents	7,513,910	3,541,338
Closing Cash and Cash Equivalents	2,494,213	7,513,910

See accompanying notes

1. NATURE OF ACTIVITIES

Haldimand County Hydro Inc. ("the Company") was incorporated under the Ontario Business Corporations Act on October 13, 2000 to provide regulated electricity distribution services to residents of Haldimand County.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) General

These financial statements have been prepared in accordance with accounting principles for electrical utilities in Ontario as required by the Ontario Energy Board under the authority of Section 70(2) of the OEB Act, 1998, of The Energy Competition Act, 1998, and reflect the following policies as set forth in the Ontario Energy Board Accounting Procedures Handbook. All principles employed are in accordance with Canadian generally accepted accounting principles.

(b) Measurement

Financial statements are based on representations that may require estimates to be made in anticipation of future transactions and events and include measurement that may, by their nature, be approximations.

(c) Inventory

Inventory is stated at the lower of cost or net realizable value. Cost is determined on a weighted average basis.

(d) Property, Plant and Equipment and Amortization

Property, plant and equipment are recorded at their historical cost. Amortization is calculated on a straight-line basis over the estimated useful service life as follows:

Buildings	50 years
Distribution stations	30 years
Distribution lines - overhead	25 years
Distribution lines - underground	25 years
Distribution transformers	25 years
Distribution meters	25 years
Rolling stock	8 years
Other capital assets	5 - 50 years

(e) Contributions in Aid of Construction

Contributions in aid of construction are reported as deferred credits and amortized over the useful life of the related property, plant and equipment. Contributions prior to 2000 are included in equity as contributed capital.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(f) Revenue Recognition

Distribution revenues are based on OEB approved distribution rates and are recognized as electricity is delivered to customers and collection is reasonably assured. Distribution revenue includes an estimate of revenue based on electricity delivered but not yet invoiced to customers from the last meter reading date to the year end.

(g) Payments in Lieu of Income Taxes (PILs)

Under the Electricity Act, 1998, the Company makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations. Prior to October 1, 2001, the Corporation was not subject to income or capital taxes.

The Company accounts for payments in lieu of corporate taxes using the liability method. Under the liability method, future income taxes reflect the net tax effects of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, as well as for tax losses available to be carried forward to future years that are likely to be realized.

(h) Financial Instruments

Financial instruments are initially recognized at fair value. Subsequent measurement is based on the classification of the financial instrument. The Company has adopted a policy to classify all financial instruments as follows:

(1) - Cash and bank are classified as Held for Trading and measured at fair value.
(2) - Accounts receivable and unbilled revenue are classified as Loans and Receivables and measured at amortized cost using the effective interest rate method.
(3) - Accounts Payable, amounts due to affiliates and long term liabilities are classified as Other Liabilities and measured at amortized cost.
(4) - Purchases and sales of financial instruments are accounted for at the trade date.
(5) - Transaction costs on financial assets and liabilities are expensed as incurred.

The Company has adopted the disclosure and presentation requirements of CICA Handbook Section 3861 rather than Handbook Sections 3862 and 3863.

(i) Regulatory Policies

The Company has adopted the following policies, as prescribed by the Ontario Energy Board (OEB) for rate-regulated enterprises. The policies have resulted in accounting treatments differing from Canadian generally accepted accounting principles for enterprises operating in a non-rate-regulated environment:

1. Various regulatory costs have been deferred in accordance with criteria set out in the OEB's Accounting Procedures handbook. In the absence of such regulation, these costs would have been expensed when incurred under Canadian GAAP.

2. The Company has deferred certain retail settlement variance amounts under the provisions of Article 490 in the OEB's Accounting Procedures handbook.

3. EMERGING ACCOUNTING CHANGES

The Accounting Standards Board (AcSB) confirmed that rate-regulated enterprises will be required to adopt International Financial Reporting Standards (IFRS) by January 1, 2011. The Public Sector Accounting Board released a decision summary confirming that government organizations following commercial practices adhere to standards for publicly accountable entities after January 1, 2011. In 2010, the AcSB granted an optional one year deferral of the adoption of IFRS for rate regulated entities and as such IFRS may be adopted for financial statements ending December 31, 2012.

Given the continued uncertainty around the timing, scope and eventual adoption of a rate-regulated accounting standard under IFRS, it is expected that the Company will elect the optional one year deferral of its adoption of IFRS. Accordingly the Company will continue to prepare its financial statements in accordance with Canadian GAAP accounting standards in Part V of the CICA Handbook for 2011.

The Company continues to assess the impact of conversion to IFRS on its results of operations. However, given the uncertainties regarding the impact of IFRS on rate regulated entities, the Company cannot reasonably quantify the full impact that adopting IFRS would have on its future financial position and the results of its operation The Company will continue to monitor accounting developments with respect to the adoption of IFRS and how any changes will impact on the Company's reporting under IFRS.

4. RATE SETTING

The rates of the Company’s electricity distribution business are subject to regulation by the OEB.

With the commencement of the open market, the Company purchases electricity from the Independent Electricity System Operator (IESO), at spot market rates and charges its customers unbundled rates. The unbundled rates include the actual cost of generation and transmission of electricity and an approved rate for electricity distribution. The cost of generation, transmission and other charges such as connection are collected by Haldimand County Hydro Inc. and remitted to the IESO. Debt retirement charges are collected and remitted to the Ontario Electricity Financial Corporation. The Company retains the distribution charge on the customer hydro invoices.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated Company. Such change in timing gives rise to the recognition of regulatory assets and liabilities. The Company’s regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. Specific regulatory assets and liabilities are disclosed in Note 6. Haldimand County Hydro Inc.'s approved rate for distribution includes components for the recovery (refund) of regulatory assets (liabilities). The approved rates, effective May 1, 2010, were calculated on a 2010 test year rate base and included a rate of return on equity of 9.85%.

5. PROPERTY, PLANT AND EQUIPMENT

	Cost	Accumulated Amortization	2010	2009
Land	139,071	-	139,071	139,071
Buildings	2,029,926	365,792	1,664,134	1,680,303
Distribution stations	466,496	150,789	315,707	345,466
Distribution lines - overhead	28,035,394	10,671,974	17,363,420	16,825,413
Distribution lines - underground	7,645,599	3,122,789	4,522,810	4,533,912
Distribution transformers	13,341,245	4,407,964	8,933,281	8,858,692
Distribution meters	2,949,488	1,077,708	1,871,780	1,968,517
Rolling stock	1,870,373	940,305	930,068	764,309
Other capital assets	4,754,790	2,651,893	2,102,897	2,120,824
	61,232,382	23,389,214	37,843,168	37,236,507

During the year, the Company disposed of conventional meters that were removed from service. For regulatory purposes, the net book value of the meters is included in property, plant and equipment. In the absence of rate regulation, the loss on the disposition of the meters would have been charged to operations.

6. REGULATORY ASSETS (LIABILITIES)

	2010	2009
Deferred payments in lieu of taxes	1,000,669	994,576
Retail settlement variance accounts	(1,447,365)	(262,686)
Recovery of regulatory asset balances	(148,557)	(137,546)
Deferred pension costs	-	205,456
Smart meters	3,350,039	2,714,945
Low voltage services	(252,960)	(476,985)
Hydro One Networks Inc.	5,994	5,240
Special purpose charge	68,911	-
	2,576,731	3,043,000

The deferred payments in lieu of taxes represents the accumulated difference in the approved estimate of taxes to be paid and the actual taxes paid.

On March 31, 2010, the OEB announced its decision regarding the Company's rate application. As part of the rate application, the OEB allowed for a recovery (refund) of various regulatory assets (liabilities). These amounts are reported as the Recovery of regulatory asset balances account (RAR). The RAR consists of various OEB approved regulatory asset (liability) account balances as at December 31, 2008.

The smart meters regulatory asset account relates to the Province of Ontario's decision to install smart meters throughout Ontario. As at December 31, 2010, the Company has installed smart meters in approximately 97% of its eligible customer base. The OEB has allowed all costs and related revenues to be recorded as a regulatory asset.

6. REGULATORY ASSETS (LIABILITIES) (continued)

The special purpose charge variance is a special charge from the OEB related to the Ministry of Energy and Infrastructure's conservation and renewable energy program costs. The OEB assessed the Company $163,046 for its share of the program. The Company is allowed to recover this charge. The amount is expected to be recovered in 2011.

The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

7. LONG TERM LIABILITIES

	2010	2009
Non-callable debenture, with graduated interest rates starting at 6% in 2000, up to 6.5% in 2010. Interest is payable semi-annually, principal is payable annually. Due May 1, 2010	-	7,670,000
Ontario Infrastructure Projects Corporation (OIPC) serial debentures, at rates from 2.92% to 4.39% with semi-annual principal payments totalling $494,248 plus interest. Due April 1, 2015, 2020 and 2025	9,759,106	-
Ontario Infrastructure Projects Corporation (OIPC) financing advance, interest payable monthly at OIPC advance interest rate calculated monthly. Advance to be repaid or converted to a debenture at completion of advances	-	4,005,730
CIBC demand loan repayable in monthly instalments of $16,667 plus interest. Interest is calculated based upon purchased bankers acceptance rates. Due December 2011	199,994	399,998
Customer Deposits	690,184	655,942
	10,649,284	12,731,670
Current portion	1,555,851	8,359,998
	9,093,433	4,371,672

7. LONG TERM LIABILITIES (continued)

Based upon current repayment terms, the estimated annual principal repayments and return of customer deposits are as follows:

2011	-	1,555,851
2012	-	1,029,270
2013	-	1,037,740
2014	-	1,039,066
2015	-	983,321

The CIBC demand instalment loan and the OIPC debentures are secured by a general security agreement on all property owned by the Company.

8. CAPITAL

	2010	2009
Capital Stock		
Authorized - an unlimited number of common shares		
Issued - 1,001 common shares	17,144,796	17,144,796
Miscellaneous Paid-in Capital	2,735,909	2,735,909
	19,880,705	19,880,705

9. OTHER OPERATING REVENUE

	2010	2009
Late payment charges	73,362	73,849
Retail service charges	32,792	32,335
Interest earned	70,191	58,741
Pole rentals	80,923	122,299
Change of occupancy charges	74,730	65,339
Collection charges	276,054	260,490
Reconnection charges	60,895	60,287
Profit on sale of material services	18,976	16,820
Water and sewer billings	365,737	362,022
Gain (loss) on disposal of property, plant and equipment	5,519	9,479
Ontario Power Authority CDM fees	60,998	40,088
Miscellaneous	68,196	184,547
Special purpose charge	94,692	-
MicroFIT monthly service charge	622	-
	1,283,687	1,286,296

10. DISTRIBUTION, OPERATION AND MAINTENANCE	2010	2009
Distribution station equipment	151,082	169,305
Overhead distribution lines	1,925,446	2,055,549
Underground distribution lines	265,926	271,864
Distribution transformers	445,518	326,289
Distribution meters	255,754	252,342
Distribution supervision and engineering	598,774	520,220
	3,642,500	3,595,569

11. INCOME TAXES - CURRENT	2010	2009
The income tax provision was calculated based on taxable income.		
Taxable income is calculated as follows:		
Income before income taxes	4,021,458	4,101,768
Amortization in excess of Capital Cost Allowance	(103,513)	31,453
Net change in regulatory assets	466,269	(2,314,930)
Regulatory assets capitalized for tax purposes	781,771	2,892,306
(Gain) Loss on disposal of assets	(5,519)	(9,479)
Other additions and deductions	51,518	42,987
Taxable income	5,211,984	4,744,105
Tax at 30.22%, (2009 - 32.03%)	1,574,922	1,519,769

12. RELATED PARTY TRANSACTIONS

The Company is a wholly owned subsidiary of Haldimand County Utilities Inc. and Haldimand County Utilities Inc. is wholly owned by The Corporation of Haldimand County. Haldimand County Utilities Inc. also owns Haldimand County Energy Inc. and Haldimand County Generation Inc. Transactions between Haldimand County Hydro Inc., Haldimand County Energy Inc., Haldimand County Generation Inc., and Haldimand County Utilities Inc. occur in the normal course of operations and consideration paid is on similar terms as transactions with unrelated parties.

13. PRUDENTIAL SUPPORT

Haldimand County Hydro Inc. is required, through the IESO, to provide security to mitigate the Company's risk of default based on its expected activity in the electricity market. The IESO could draw on this guarantee if Haldimand County Hydro Inc. fails to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2010, the Company provided prudential support in the form of bank letters of credit of $1,796,505. The letters of credit are secured by a general security agreement on all property owned by the Company.

14. CAPITAL MANAGEMENT

The Company's objectives when managing capital are to maintain financial stability such that it can continue to provide returns for the shareholder and benefits for other stakeholders. The Company meets its objectives for managing capital by management oversight and Board monitoring of total capital.

The Company's total capital as at December 31, consists of:

	2010	2009
Total long term liabilities	10,649,284	12,731,670
Less: cash and bank	2,494,213	7,513,910
Net long term liabilities	8,155,071	5,217,760
Total shareholder's equity	32,637,496	30,540,532
Total capital	40,792,567	35,758,292

15. FINANCIAL INSTRUMENTS

Management and the Board monitor and respond as necessary to any risks arising from financial instruments.

Fair Value

The fair value of financial instruments such as cash and bank, accounts receivable, unbilled revenue and accounts payables and accrued liabilities are determined to approximate their recorded value due to their short term maturity.

Interest Rate Risk

The Company's exposure to interest rate risk relates to its floating bank rate indebtedness (see Note 7).

Credit Risk

The Company's exposure to credit risk relates to its accounts receivable and unbilled revenue. The Company collects security deposits from customers in accordance with direction provided by the OEB. The Company held deposits of $690,184 at year end in order to mitigate credit risk.

16. COMPARATIVE FIGURES

Certain of the prior year's figures, provided for purposes of comparison, have been reclassified to conform with the current year's presentation.

17. CONTINGENCIES

Late Payment Charges Class Action

By order dated July 22, 2010, the Ontario Supreme Court settled the class action suit. The settlement required all Municipal Electric Utilities to pay $17,000.000 plus costs and taxes. The amount allocated to the Company was $52,104. The OEB has allowed the amount to be recovered through future rates.

Other

A claim has been filed against the Company related to stray voltage. At this time, it is not possible to quantify the effect, if any, of this claim on the financial statements of the Company, consequently no provision for a loss, if any, has been recorded in these financial statements.

HALDIMAND COUNTY HYDRO INC.

FINANCIAL STATEMENTS

For the year ended December 31, 2011

Millard, Rouse & Rosebrugh LLP
Chartered Accountants

HALDIMAND COUNTY HYDRO INC.

For the year ended December 31, 2011

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Millard, Rouse & Rosebrugh LLP
Chartered Accountants
P.O. Box 57, 91 Main Street South
Hagersville, Ontario N0A 1H0
Telephone: (905) 768-5883
Facsimile: (905) 768-5843

INDEPENDENT AUDITORS' REPORT

To the Shareholder of
Haldimand County Hydro Inc.

We have audited the accompanying financial statements of Haldimand County Hydro Inc., which comprise the statement of financial position as at December 31, 2011, and the statements of income, retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

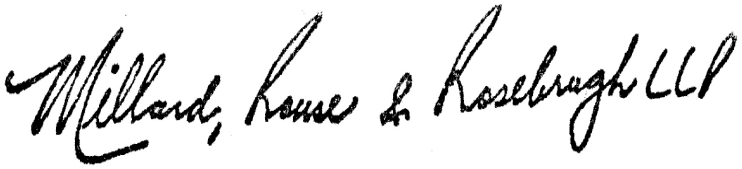
Management's Responsibility for the Financial Statements
Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility
Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgement, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the financial statements present fairly, in all material respects, the financial position of Haldimand County Hydro Inc. as at December 31, 2011, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.



March 29, 2012

CHARTERED ACCOUNTANTS
Licensed Public Accountants

HALDIMAND COUNTY HYDRO INC.

STATEMENT OF FINANCIAL POSITION

As at December 31	2011	2010
ASSETS		
Current Assets		
Cash and bank	3,941,761	2,494,213
Unbilled revenue	5,422,772	5,259,993
Accounts receivable	3,331,452	3,192,917
OPA conservation program	-	107,499
Inventory	1,254,484	1,113,623
Income taxes recoverable	585,578	33,073
Prepaid expenses	270,855	212,360
	14,806,902	12,413,678
Property, Plant and Equipment (Note 5)	39,793,680	37,843,168
Regulatory Assets (Note 6)	2,284,829	2,576,731
Future Tax Asset	1,271,300	1,182,173
	58,156,711	54,015,750
LIABILITIES		
Current Liabilities		
Accounts payable and accrued expenses	7,696,114	7,051,105
OPA conservation program	3,281	-
Due to Haldimand County Energy Inc.	623,474	563,271
Due to Haldimand County Utilities Inc.	17,490	19,134
Current portion of long term liabilities	1,023,662	1,555,851
	9,364,021	9,189,361
Long Term Liabilities (Note 7)	11,386,158	9,093,433
	20,750,179	18,282,794
Deferred Credits		
Contributions in aid of construction	3,953,284	3,786,815
Less: Amortization to date	846,180	691,355
	3,107,104	3,095,460
SHAREHOLDER'S EQUITY		
Capital (Note 8)	19,880,705	19,880,705
Retained Earnings (Page 3)	14,418,723	12,756,791
	34,299,428	32,637,496
	58,156,711	54,015,750

See accompanying notes

HALDIMAND COUNTY HYDRO INC.

STATEMENT OF RETAINED EARNINGS

For the year ended December 31	2011	2010
Retained Earnings - Beginning of Year	12,756,791	10,659,827
Net income	2,378,682	2,788,409
Dividends	(716,750)	(691,445)
Retained Earnings - End of Year	14,418,723	12,756,791

See accompanying notes

HALDIMAND COUNTY HYDRO INC.

STATEMENT OF INCOME

For the year ended December 31	2011	2010
Service Revenue		
Residential	11,240,324	10,311,195
General	10,434,535	8,941,377
Street lighting	160,904	160,799
Sentinel lighting	24,383	23,323
Embedded Distributor	5,398,454	5,530,280
Retailer	4,816,833	4,593,215
Retail transmission and low voltage	5,379,871	4,969,886
Regulatory	2,925,537	2,909,386
Distribution services	12,875,589	13,024,493
	53,256,430	50,463,954
Cost of Power	40,380,841	37,439,461
Gross Margin on Service Revenue	12,875,589	13,024,493
Other Operating Revenue (Note 9)	1,279,958	1,283,687
	14,155,547	14,308,180
Expenses		
Distribution, operation and maintenance (Note 10)	4,128,599	3,642,500
Community relations	45,426	42,643
Billing and collecting	1,154,952	1,305,989
General administration	1,972,174	1,854,560
Directors	57,207	48,832
	7,358,358	6,894,524
Amortization	3,129,016	2,973,032
Less: Amortization of contributions in aid of construction	154,826	144,566
	2,974,190	2,828,466
	10,332,548	9,722,990
Income Before Interest and Income Taxes	3,822,999	4,585,190
Interest expense	485,501	563,732
Income Before Income Taxes	3,337,498	4,021,458
Income taxes - current (Note 11)	1,047,943	1,574,922
- future	(89,127)	(341,873)
	958,816	1,233,049
Net Income	2,378,682	2,788,409

See accompanying notes

HALDIMAND COUNTY HYDRO INC.

STATEMENT OF CASH FLOWS

For the year ended December 31	2011	2010
Cash Flows from Operating Activities		
Net Income	2,378,682	2,788,409
Charges (credits) to income not involving cash		
Amortization	3,132,661	2,973,032
Amortization of contributions in aid of capital	(154,826)	(144,566)
(Gain) loss on disposal of property, plant and equipment	(21,350)	(5,519)
Future income taxes	(89,127)	(341,873)
	5,246,040	5,269,483
Net change in non-cash working capital balances related to operations	(238,827)	(4,741,179)
	5,007,213	528,304
Cash Flows from Financing Activities		
Dividends	(716,750)	(691,445)
Deposits from customers (net)	(216,703)	34,242
Contributions in aid of construction	166,470	330,500
Long term debt	1,977,239	(2,116,628)
Deferred financing costs	-	3,235
	1,210,256	(2,440,096)
Cash Flows from Investing Activities		
Purchase of property, plant and equipment	(5,094,166)	(3,587,264)
Proceeds on disposal of property, plant and equipment	32,343	13,090
Regulatory assets/liabilities	291,902	466,269
	(4,769,921)	(3,107,905)
Net Increase in Cash and Cash Equivalents	1,447,548	(5,019,697)
Opening Cash and Cash Equivalents	2,494,213	7,513,910
Closing Cash and Cash Equivalents	3,941,761	2,494,213

See accompanying notes

1. NATURE OF ACTIVITIES

Haldimand County Hydro Inc. ("the Company") was incorporated under the Ontario Business Corporations Act on October 13, 2000 to provide regulated electricity distribution services to residents of Haldimand County.

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(a) General

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Distribution meters	25 years
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Other capital assets	5 - 50 years

(e) Contributions in Aid of Construction

Contributions in aid of construction are reported as deferred credits and amortized over the useful life of the related property, plant and equipment. Contributions prior to 2000 are included in equity as contributed capital.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(f) Revenue Recognition

Distribution revenues are based on OEB approved distribution rates and are recognized as electricity is delivered to customers and collection is reasonably assured. Distribution revenue includes an estimate of revenue based on electricity delivered but not yet invoiced to customers from the last meter reading date to the year end.

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(5) - Transaction costs on financial assets and liabilities are expensed as incurred.

The Company has adopted the disclosure and presentation requirements of CICA Handbook Section 3861 rather than Handbook Sections 3862 and 3863.

(i) Regulatory Policies

The Company has adopted the following policies, as prescribed by the Ontario Energy Board (OEB) for rate-regulated enterprises. The policies have resulted in accounting treatments differing from Canadian generally accepted accounting principles for enterprises operating in a non-rate-regulated environment:

1. Various regulatory costs have been deferred in accordance with criteria set out in the OEB's Accounting Procedures handbook. In the absence of such regulation, these costs would have been expensed when incurred under Canadian GAAP.

2. The Company has deferred certain retail settlement variance amounts under the provisions of Article 490 in the OEB's Accounting Procedures handbook.

3. EMERGING ACCOUNTING CHANGES

The Accounting Standards Board (AcSB) confirmed that rate-regulated enterprises will be required to adopt International Financial Reporting Standards (IFRS) by January 1, 2011. The Public Sector Accounting Board released a decision summary confirming that government organizations following commercial practices adhere to standards for publicly accountable entities after January 1, 2011. In 2010, the AcSB granted an optional one year deferral of the adoption of IFRS for rate regulated entities and as such IFRS may be adopted for financial statements ending December 31, 2012.

The Company has taken the optional one year deferral of its adoption of IFRS. Accordingly the Company has prepared its financial statements in accordance with Part V of the CICA Handbook "Pre-Changeover Accounting Standards" for 2011.

The Company continues to assess the impact of conversion to IFRS on its results of operations. The Company will continue to monitor accounting developments with respect to the adoption of IFRS and how any changes will impact on the Company's reporting under IFRS.

4. RATE SETTING

The rates of the Company’s electricity distribution business are subject to regulation by the OEB.

With the commencement of the open market, the Company purchases electricity from the Independent Electricity System Operator (IESO), at spot market rates and charges its customers unbundled rates. The unbundled rates include the actual cost of generation and transmission of electricity and an approved rate for electricity distribution. The cost of generation, transmission and other charges such as connection are collected by Haldimand County Hydro Inc. and remitted to the IESO. Debt retirement charges are collected and remitted to the Ontario Electricity Financial Corporation. The Company retains the distribution charge on the customer hydro invoices.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated Company. Such change in timing gives rise to the recognition of regulatory assets and liabilities. The Company’s regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. Specific regulatory assets and liabilities are disclosed in Note 6. Haldimand County Hydro Inc.'s approved rate for distribution includes components for the recovery (refund) of regulatory assets (liabilities). The approved rates, effective May 1, 2011, were calculated on a 2010 test year rate base and included a rate of return on equity of 9.85%.

5. PROPERTY, PLANT AND EQUIPMENT

	Cost	Accumulated Amortization	2011	2010
Land	131,280	-	131,280	139,071
Buildings	2,168,016	416,249	1,751,767	1,664,134
Distribution stations	466,496	168,055	298,441	315,707
Distribution lines - overhead	31,166,171	12,022,304	19,143,867	17,363,420
Distribution lines - underground	7,925,971	3,471,497	4,454,474	4,522,810
Distribution transformers	14,165,868	4,971,073	9,194,795	8,933,281
Distribution meters	3,131,706	1,196,056	1,935,650	1,871,780
Rolling stock	2,087,569	1,061,752	1,025,817	930,068
Other capital assets	4,936,465	3,078,876	1,857,589	2,102,897
	66,179,542	26,385,862	39,793,680	37,843,168

In 2010 and 2011, the Company disposed of conventional meters that were removed from service. For regulatory purposes, the net book value of the meters is included in property, plant and equipment. In the absence of rate regulation, the loss on the disposition of the meters would have been charged to operations.

6. REGULATORY ASSETS (LIABILITIES)

	2011	2010
Deferred payments in lieu of taxes	1,011,901	1,000,669
Retail settlement variance accounts	(1,806,073)	(1,447,365)
Recovery of regulatory asset balances	(345,351)	(148,557)
Smart meters	3,508,788	3,350,039
Low voltage services	(113,364)	(252,960)
Hydro One Networks Inc.	6,081	5,994
Special purpose charge	22,847	68,911
	2,284,829	2,576,731

The deferred payments in lieu of taxes represents the accumulated difference in the approved estimate of taxes to be paid and the actual taxes paid.

On April 6, 2011, the OEB announced its decision regarding the Company's rate application. As part of the rate application, the OEB allowed for a recovery (refund) of various regulatory assets (liabilities). These amounts are reported as the Recovery of regulatory asset balances account (RAR). The RAR consists of various OEB approved regulatory asset (liability) account balances as at December 31, 2009.

The smart meters regulatory asset account relates to the Province of Ontario's decision to install smart meters throughout Ontario. As at December 31, 2011, the Company has installed smart meters in almost 100% of its eligible customer base. The OEB has allowed all costs and related revenues to be recorded as a regulatory asset.

6. REGULATORY ASSETS (LIABILITIES) (continued)

The special purpose charge variance is a special charge from the OEB related to the Ministry of Energy and Infrastructure's conservation and renewable energy program costs. The OEB assessed the Company $163,046 for its share of the program. The Company is allowed to recover this charge. The amount has been included in rates, effective May 1, 2012.

The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

7. LONG TERM LIABILITIES

	2011	2010
Ontario Infrastructure Projects Corporation (OIPC) serial debentures, at rates from 2.92% to 4.39% with semi-annual principal payments totalling $494,248 plus interest. Due April 1, 2015, 2020 and 2025	8,770,604	9,759,106
Ontario Infrastructure and Lands Corporation (OILC) financing advance, interest payable monthly at OILC advance interest rate calculated monthly. Advance to be repaid or converted to a debenture at completion of advances	3,165,735	-
CIBC demand loan repayable in monthly instalments of $16,667 plus interest. Interest is calculated based upon purchased bankers acceptance rates. Due December 2011	-	199,994
Customer Deposits	473,481	690,184
	12,409,820	10,649,284
Current portion	1,023,662	1,555,851
	11,386,158	9,093,433

7. LONG TERM LIABILITIES (continued)

Based upon current repayment terms, the estimated annual principal repayments and return of customer deposits are as follows:

2012	-	1,023,662
2013	-	1,026,679
2014	-	1,031,808
2015	-	976,476
2016	-	865,681

The OIPC debentures and the OILC advances are secured by a general security agreement on all property owned by the Company.

8. CAPITAL

	2011	2010
Capital Stock		
Authorized - an unlimited number of common shares		
Issued - 1,001 common shares	17,144,796	17,144,796
Miscellaneous Paid-in Capital	2,735,909	2,735,909
	19,880,705	19,880,705

9. OTHER OPERATING REVENUE

	2011	2010
Late payment charges	68,188	73,362
Retail service charges	30,425	32,792
Interest earned	105,737	70,191
Pole rentals	86,987	80,923
Change of occupancy charges	76,290	74,730
Collection charges	220,830	276,054
Reconnection charges	27,095	60,895
Profit on sale of material services	22,402	18,976
Water and sewer billings	364,650	365,737
Gain (loss) on disposal of property, plant and equipment	21,350	5,519
Ontario Power Authority CDM fees	59,153	60,998
Miscellaneous	144,190	68,196
Special purpose charge	46,517	94,692
MicroFIT monthly service charge	6,144	622
	1,279,958	1,283,687

10. DISTRIBUTION, OPERATION AND MAINTENANCE	2011	2010
Distribution station equipment	273,608	151,082
Overhead distribution lines	2,184,159	1,925,446
Underground distribution lines	230,768	265,926
Distribution transformers	496,830	445,518
Distribution meters	258,936	255,754
Distribution supervision and engineering	684,298	598,774
	4,128,599	3,642,500

11. INCOME TAXES - CURRENT	2011	2010
The income tax provision was calculated based on taxable income.		
Taxable income is calculated as follows:		
Income before income taxes	3,337,498	4,021,458
Amortization in excess of Capital Cost Allowance	50,471	(103,513)
Net change in regulatory assets	291,902	466,269
Regulatory assets capitalized for tax purposes	258,384	781,771
(Gain) Loss on disposal of assets	(21,350)	(5,519)
Other additions and deductions	51,833	51,518
Taxable income	3,968,738	5,211,984
Tax at 26.40%, (2010 - 30.22%)	1,047,943	1,574,922

12. RELATED PARTY TRANSACTIONS

The Company is a wholly owned subsidiary of Haldimand County Utilities Inc. and Haldimand County Utilities Inc. is wholly owned by The Corporation of Haldimand County. Haldimand County Utilities Inc. also owns Haldimand County Energy Inc. and Haldimand County Generation Inc. Transactions between Haldimand County Hydro Inc., Haldimand County Energy Inc., Haldimand County Generation Inc., and Haldimand County Utilities Inc. occur in the normal course of operations and consideration paid is on similar terms as transactions with unrelated parties.

13. PRUDENTIAL SUPPORT

Haldimand County Hydro Inc. is required, through the IESO, to provide security to mitigate the Company's risk of default based on its expected activity in the electricity market. The IESO could draw on this guarantee if Haldimand County Hydro Inc. fails to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2011, the Company provided prudential support in the form of bank letters of credit of $1,796,505. The letters of credit are secured by a general security agreement on all property owned by the Company.

14. CAPITAL MANAGEMENT

The Company's objectives when managing capital are to maintain financial stability such that it can continue to provide returns for the shareholder and benefits for other stakeholders. The Company meets its objectives for managing capital by management oversight and Board monitoring of total capital.

The Company's total capital as at December 31, consists of:

	2011	2010
Total long term liabilities	12,409,820	10,649,284
Less: cash and bank	3,941,761	2,494,213
Net long term liabilities	8,468,059	8,155,071
Total shareholder's equity	34,299,428	32,637,496
Total capital	42,767,487	40,792,567

15. FINANCIAL INSTRUMENTS

Management and the Board monitor and respond as necessary to any risks arising from financial instruments.

Fair Value

The fair value of financial instruments such as cash and bank, accounts receivable, unbilled revenue and accounts payables and accrued liabilities are determined to approximate their recorded value due to their short term maturity.

Interest Rate Risk

The Company's exposure to interest rate risk relates to its floating bank rate indebtedness (see Note 7).

Credit Risk

The Company's exposure to credit risk relates to its accounts receivable and unbilled revenue. The Company collects security deposits from customers in accordance with direction provided by the OEB. The Company held deposits of $473,481 at year end in order to mitigate credit risk.

16. CONTINGENCIES

A claim has been filed against the Company related to stray voltage. At this time, it is not possible to quantify the effect, if any, of this claim on the financial statements of the Company, consequently no provision for a loss, if any, has been recorded in these financial statements.

HALDIMAND COUNTY HYDRO INC.

FINANCIAL STATEMENTS

For the year ended December 31, 2012

Millard, Rouse & Rosebrugh LLP
Chartered Accountants

HALDIMAND COUNTY HYDRO INC.

For the year ended December 31, 2012

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Millard, Rouse & Rosebrugh LLP
Chartered Accountants
P.O. Box 57, 91 Main Street South
Hagersville, Ontario N0A 1H0
Telephone: (905) 768-5883
Facsimile: (905) 768-5843

INDEPENDENT AUDITORS' REPORT

To the Shareholder of
Haldimand County Hydro Inc.

We have audited the accompanying financial statements of Haldimand County Hydro Inc., which comprise the statement of financial position as at December 31, 2012, and the statements of retained earnings, income and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

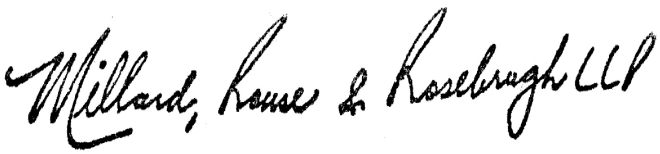
Management's Responsibility for the Financial Statements
Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility
Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgement, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the financial statements present fairly, in all material respects, the financial position of Haldimand County Hydro Inc. as at December 31, 2012, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.



April 3, 2013

CHARTERED ACCOUNTANTS
Licensed Public Accountants

HALDIMAND COUNTY HYDRO INC.

STATEMENT OF FINANCIAL POSITION

As at December 31	2012	2011
ASSETS		
Current Assets		
Cash and bank	5,733,888	3,991,761
Unbilled revenue	5,589,542	5,422,772
Accounts receivable	4,509,456	3,331,452
OPA conservation program	160	-
Inventory	1,334,139	1,254,484
Payments in lieu of income taxes recoverable	588,086	585,578
Prepaid expenses	276,994	270,855
	18,032,265	14,856,902
Property, Plant and Equipment (Note 5)	45,030,723	39,793,680
Regulatory Assets (Note 6)	-	2,284,829
Future Tax Asset	1,615,829	1,271,300
	64,678,817	58,206,711
LIABILITIES		
Current Liabilities		
Accounts payable and accrued expenses	9,148,218	7,696,114
OPA conservation program	-	3,281
Due to Haldimand County Energy Inc.	738,283	673,474
Due to Haldimand County Utilities Inc.	26,826	17,490
Current portion of long term liabilities	1,354,948	1,023,662
	11,268,275	9,414,021
Regulatory Liabilities (Note 6)	2,106,320	-
Long Term Liabilities (Note 7)	13,698,310	11,386,158
	27,072,905	20,800,179
Deferred Credits		
Contributions in aid of construction	4,143,672	3,953,284
Less: Amortization to date	1,007,444	846,180
	3,136,228	3,107,104
SHAREHOLDER'S EQUITY		
Capital (Note 8)	19,880,705	19,880,705
Retained Earnings (Page 3)	14,588,979	14,418,723
	34,469,684	34,299,428
	64,678,817	58,206,711

See accompanying notes

HALDIMAND COUNTY HYDRO INC.

STATEMENT OF RETAINED EARNINGS

For the year ended December 31	2012	2011
Retained Earnings - Beginning of Year	14,418,723	12,756,791
Net income	781,585	2,378,682
Dividends	(611,329)	(716,750)
Retained Earnings - End of Year	14,588,979	14,418,723

See accompanying notes

HALDIMAND COUNTY HYDRO INC.

STATEMENT OF INCOME

For the year ended December 31	2012	2011
Service Revenue (Note 9)	54,238,770	53,256,430
Cost of Power	39,895,541	40,380,841
Gross Margin on Service Revenue	14,343,229	12,875,589
Other Operating Revenue (Note 10)	1,218,856	1,279,958
	15,562,085	14,155,547
Expenses		
Distribution, operation and maintenance (Note 11)	4,373,098	4,128,599
Community relations	143,208	45,426
Billing and collecting	1,867,865	1,154,952
General administration	1,934,590	1,972,174
Directors	102,865	57,207
	8,421,626	7,358,358
Amortization	4,097,540	3,129,016
Less: Amortization of contributions in aid of construction	161,264	154,826
	3,936,276	2,974,190
	12,357,902	10,332,548
Income Before Undernoted Items	3,204,183	3,822,999
Interest expense	535,593	485,501
Income Before Income Taxes and Regulatory Adjustment	2,668,590	3,337,498
Income taxes - current (Note 13)	507,107	1,047,943
- future	179,738	(89,127)
	686,845	958,816
Income Before Regulatory Adjustment	1,981,745	2,378,682
Regulatory adjustment - payment in lieu of taxes (Note 12)	1,724,427	-
- future tax impact of adjustment	(524,267)	-
Net regulatory adjustment	1,200,160	-
Net Income	781,585	2,378,682

See accompanying notes

HALDIMAND COUNTY HYDRO INC.

STATEMENT OF CASH FLOWS

For the year ended December 31	2012	2011
Cash Flows from Operating Activities		
Net Income	781,585	2,378,682
Charges (credits) to income not involving cash		
Amortization	4,101,870	3,132,661
Amortization of contributions in aid of capital	(161,264)	(154,826)
(Gain) loss on disposal of property, plant and equipment	(112,536)	(21,350)
Future income taxes	(344,529)	(89,127)
	4,265,126	5,246,040
Net change in non-cash working capital balances related to operations	89,732	(238,827)
	4,354,858	5,007,213
Cash Flows from Financing Activities		
Dividends	(611,329)	(716,750)
Deposits from customers, retailers and contractors (net)	71,031	(216,703)
Contributions in aid of construction	190,388	166,470
Long term debt	2,572,407	1,977,239
Regulatory liabilities	2,106,320	-
	4,328,817	1,210,256
Cash Flows from Investing Activities		
Purchase of property, plant and equipment	(9,345,962)	(5,094,166)
Proceeds on disposal of property, plant and equipment	119,585	32,343
Regulatory assets	2,284,829	291,902
	(6,941,548)	(4,769,921)
Net Increase in Cash and Cash Equivalents	1,742,127	1,447,548
Opening Cash and Cash Equivalents	3,991,761	2,544,213
Closing Cash and Cash Equivalents	5,733,888	3,991,761

See accompanying notes

1. NATURE OF ACTIVITIES

Haldimand County Hydro Inc. ("the Company") was incorporated under the Ontario Business Corporations Act on October 13, 2000 to provide regulated electricity distribution services to residents of Haldimand County.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) General

These financial statements have been prepared in accordance with accounting principles for electrical utilities in Ontario as required by the Ontario Energy Board (OEB) under the authority of Section 70(2) of the OEB Act, 1998, of The Energy Competition Act, 1998, and reflect the following policies as set forth in the Ontario Energy Board Accounting Procedures Handbook. All principles employed are in accordance with Canadian generally accepted accounting principles.

(b) Measurement

Financial statements are based on representations that may require estimates to be made in anticipation of future transactions and events and include measurement that may, by their nature, be approximations.

(c) Inventory

Inventory is stated at the lower of cost or net realizable value. Cost is determined on a weighted average basis.

(d) Property, Plant and Equipment and Amortization

Property, plant and equipment are recorded at their historical cost. Amortization is calculated on a straight-line basis over the estimated useful service life as follows:

Buildings	50 years
Distribution stations	30 years
Distribution lines - overhead	25 years
Distribution lines - underground	25 years
Distribution transformers	25 years
Distribution meters	25 years
Rolling stock	8 years
Other capital assets	5 - 50 years

(e) Contributions in Aid of Construction

Contributions in aid of construction are reported as deferred credits and amortized over the useful life of the related property, plant and equipment. Contributions prior to 2000 are included in equity as contributed capital.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(f) Revenue Recognition

Distribution revenues are based on OEB approved distribution rates and are recognized as electricity is delivered to customers and collection is reasonably assured. Distribution revenue includes an estimate of revenue based on electricity delivered but not yet invoiced to customers from the last meter reading date to the year end.

(g) Payments in Lieu of Income Taxes (PILs)

Under the Electricity Act, 1998, the Company makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations. Prior to October 1, 2001, the Corporation was not subject to income or capital taxes.

The Company accounts for payments in lieu of corporate taxes using the liability method. Under the liability method, future income taxes reflect the net tax effects of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, as well as for tax losses available to be carried forward to future years that are likely to be realized.

(h) Financial Instruments

Financial instruments are initially recognized at fair value. Subsequent measurement is based on the classification of the financial instrument. The Company has adopted a policy to classify all financial instruments as follows:

(1) - Cash and bank are classified as Held for Trading and measured at fair value.
(2) - Accounts receivable and unbilled revenue are classified as Loans and Receivables and measured at amortized cost using the effective interest rate method.
(3) - Accounts Payable, amounts due to affiliates and long term liabilities are classified as Other Liabilities and measured at amortized cost.
(4) - Purchases and sales of financial instruments are accounted for at the trade date.
(5) - Transaction costs on financial assets and liabilities are expensed as incurred.

The Company has adopted the disclosure and presentation requirements of CICA Handbook Section 3861 rather than Handbook Sections 3862 and 3863.

(i) Regulatory Policies

The Company has adopted the following policies, as prescribed by the OEB for rate-regulated enterprises. The policies have resulted in accounting treatments differing from Canadian generally accepted accounting principles for enterprises operating in a non-rate-regulated environment:

1. Various regulatory costs have been deferred in accordance with criteria set out in the OEB's Accounting Procedures handbook. In the absence of such regulation, these costs would have been expensed when incurred under Canadian GAAP.

2. The Company has deferred certain retail settlement variance amounts under the provisions of Article 490 in the OEB's Accounting Procedures handbook.

3. EMERGING ACCOUNTING CHANGES

The Accounting Standards Board (AcSB) confirmed that rate-regulated enterprises were to be required to adopt International Financial Reporting Standards (IFRS) by January 1, 2011. The Public Sector Accounting Board released a decision summary confirming that government organizations following commercial practices adhere to standards for publicly accountable entities after January 1, 2011. This was deferred by two years. In March 2013, the AcSB granted an additional optional two year deferral of the adoption of IFRS for rate regulated entities and as such IFRS may be adopted for financial statements ending December 31, 2015.

The Company has taken the additional deferrals of its adoption of IFRS. Accordingly the Company has prepared its financial statements in accordance with Part V of the CICA Handbook "Pre-Changeover Accounting Standards" for 2012.

The Company continues to assess the impact of conversion to IFRS on its results of operations. The Company will continue to monitor accounting developments with respect to the adoption of IFRS and how any changes will impact on the Company's reporting under IFRS.

4. RATE SETTING

The rates of the Company’s electricity distribution business are subject to regulation by the OEB.

With the commencement of the open market, the Company purchases electricity from the Independent Electricity System Operator (IESO), at spot market rates and charges its customers unbundled rates. The unbundled rates include the actual cost of generation and transmission of electricity and an approved rate for electricity distribution. The cost of generation, transmission and other charges such as connection are collected by Haldimand County Hydro Inc. and remitted to the IESO. Debt retirement charges are collected and remitted to the Ontario Electricity Financial Corporation. The Company retains the distribution charge on the customer hydro invoices.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated Company. Such change in timing gives rise to the recognition of regulatory assets and liabilities. The Company’s regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. Specific regulatory assets and liabilities are disclosed in Note 6. Haldimand County Hydro Inc.'s approved rate for distribution includes components for the recovery (refund) of regulatory assets (liabilities). The approved rates, effective May 1, 2012, were calculated on a 2010 test year rate base and included a rate of return on equity of 9.85%.

5. PROPERTY, PLANT AND EQUIPMENT

	Cost	Accumulated Amortization	2012	2011
Land	127,140	-	127,140	131,280
Buildings	2,190,518	467,768	1,722,750	1,751,767
Distribution stations	466,496	185,350	281,146	298,441
Distribution lines - overhead	34,184,427	13,500,017	20,684,410	19,143,867
Distribution lines - underground	9,068,449	3,813,842	5,254,607	4,454,474
Distribution transformers	15,070,996	5,568,712	9,502,284	9,194,795
Distribution meters	6,758,882	2,070,790	4,688,092	1,935,650
Rolling stock	2,207,645	1,183,301	1,024,344	1,025,817
Other capital assets	5,274,302	3,528,352	1,745,950	1,857,589
	75,348,855	30,318,132	45,030,723	39,793,680

6. REGULATORY ASSETS (LIABILITIES)

	2012	2011
Deferred payments in lieu of taxes	-	1,011,901
Retail settlement variance accounts	(858,095)	(1,806,073)
Recovery of regulatory asset balances	(1,197,158)	(345,351)
Smart meters	(4,491)	3,508,788
Low voltage services	(52,744)	(113,364)
Hydro One Networks Inc.	6,168	6,081
Special purpose charge	-	22,847
	(2,106,320)	2,284,829

The deferred payments in lieu of taxes represents the accumulated difference in the approved estimate of taxes to be paid and the actual taxes paid.

On April 4, 2012, the OEB announced its decision regarding the Company's rate application. As part of the rate application, the OEB allowed for a recovery (refund) of various regulatory assets (liabilities). These amounts are reported as the Recovery of regulatory asset balances account (RAR). The RAR consists of various OEB approved regulatory asset (liability) account balances as at December 31, 2010.

In 2012, the OEB settled the Deferred payments-in-lieu of taxes regulatory accounts. The OEB adjusted this balance to a liability of $705,925 including interest (see note 12). The balance owing to customers as at December 31, 2012 is $641,504. This amount is included in the Recovery of regulatory asset balances noted above.

The smart meters regulatory asset account relates to the Province of Ontario's decision to install smart meters throughout Ontario. As at December 31, 2012, the Company has installed its smart meters and received OEB approval for the disposition of and recovery of costs related to smart meters.

6. REGULATORY ASSETS (LIABILITIES) (continued)

The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

7. LONG TERM LIABILITIES

	2012	2011
Ontario Infrastructure and Lands Corporation (OILC)		
Interest bearing debentures with semi annual payments of principal and interest:		
(a) Interest at 2.92%, semi-annual payments of $96,499 plus interest, due April 2015.	482,496	675,495
(b) Interest at 3.90%, semi-annual payments of $264,418 plus interest, due April 2020	3,966,273	4,495,109
(c) Interest at 4.39%, semi-annual payments of $133,333 plus interest, due April 2025	3,333,333	3,600,000
(d) Interest at 3.77%, semi-annual payments of $120,521 plus interest, due September 2037	6,026,065	-
(e) Interest at 2.91%, semi-annual payments of $35,029 plus interest, due September 2022	700,579	-
Other		
OILC financing advance, interest payable monthly at OILC advance interest rate calculated monthly.	-	3,165,735
Customer, retailer and contractor deposits	544,512	473,481
	15,053,258	12,409,820
Current portion	1,354,948	1,023,662
	13,698,310	11,386,158

7. LONG TERM LIABILITIES (continued)

Based upon current repayment terms, the estimated annual principal repayments and return of customer deposits are as follows:

2013	-	1,354,948
2014	-	1,342,078
2015	-	1,303,767
2016	-	1,165,852
2017	-	1,176,202

The OILC debentures are secured by a general security agreement on all property owned by the Company.

8. CAPITAL

	2012	2011
Capital Stock		
Authorized - an unlimited number of common shares		
Issued - 1,001 common shares	17,144,796	17,144,796
Miscellaneous Paid-in Capital	2,735,909	2,735,909
	19,880,705	19,880,705

9. SERVICE REVENUE

	2012	2011
Residential	12,420,910	11,240,324
General	8,843,891	10,434,535
Street lighting	18,911	160,904
Sentinel lighting	23,493	24,383
Embedded Distributor	5,258,988	5,398,454
Retailer	6,216,878	4,816,833
Retail transmission and low voltage	5,038,539	5,379,871
Regulatory	2,073,930	2,925,537
Distribution services	14,343,230	12,875,589
	54,238,770	53,256,430

10. OTHER OPERATING REVENUE

	2012	2011
Late payment charges	66,213	68,188
Retail service charges	27,137	30,425
Interest earned	(13,042)	105,737
Pole rentals	76,396	86,987
Change of occupancy charges	81,660	76,290
Collection charges	253,170	220,830
Reconnection charges	30,240	27,095
Profit on sale of material services	19,646	22,402
Water and sewer billings	374,857	364,650
Gain (loss) on disposal of property, plant and equipment	112,536	21,350
Ontario Power Authority CDM fees	25,101	59,153
Miscellaneous	154,277	144,190
Special purpose charge	-	46,517
MicroFIT monthly service charge	10,665	6,144
	1,218,856	1,279,958

11. DISTRIBUTION, OPERATION AND MAINTENANCE

	2012	2011
Distribution station equipment	67,623	273,608
Overhead distribution lines	2,120,168	2,184,159
Underground distribution lines	342,191	230,768
Distribution transformers	576,537	496,830
Distribution meters	509,933	258,936
Distribution supervision and engineering	756,646	684,298
	4,373,098	4,128,599

12. OEB DECISION ON CERTAIN REGULATORY ASSETS

The OEB issued its decision and order regarding the disposition of account 1562, Deferred Payments in Lieu of Taxes, on August 30, 2012. The decision set the account balance at a liability of $705,923, including principal and interest. The required adjustment of $1,724,427 has been recorded in the Statement of Income after net income from operations.

13. INCOME TAXES - CURRENT

	2012	2011
The income tax provision was calculated based on taxable income.		
Taxable income is calculated as follows:		
Income before income taxes	2,668,590	3,337,498
Less regulatory adjustment	(1,724,427)	-
Amortization in excess of Capital Cost Allowance	703,304	50,471
Net change in regulatory assets/liabilities	4,391,149	291,902
Regulatory assets capitalized for tax purposes	(3,669,190)	258,384
(Gain) Loss on disposal of assets	(112,536)	(21,350)
Other additions and deductions	(207,848)	51,833
Taxable income	2,049,042	3,968,738
Tax at 24.75% (2011 - 26.40%)	507,107	1,047,943

14. RELATED PARTY TRANSACTIONS

The Company is a wholly owned subsidiary of Haldimand County Utilities Inc. and Haldimand County Utilities Inc. is wholly owned by The Corporation of Haldimand County. Haldimand County Utilities Inc. also owns Haldimand County Energy Inc. and Haldimand County Generation Inc. Transactions between Haldimand County Hydro Inc., Haldimand County Energy Inc., Haldimand County Generation Inc., and Haldimand County Utilities Inc. occur in the normal course of operations and consideration paid is on similar terms as transactions with unrelated parties.

15. PRUDENTIAL SUPPORT

Haldimand County Hydro Inc. is required, through the IESO, to provide security to mitigate the Company's risk of default based on its expected activity in the electricity market. The IESO could draw on this guarantee if Haldimand County Hydro Inc. fails to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2012, the Company provided prudential support in the form of bank letters of credit of $1,796,505. The letters of credit are secured by a general security agreement on all property owned by the Company.

16. COMPARATIVE FIGURES

Certain of the prior year's figures, provided for purposes of comparison, have been reclassified to conform with the current year's presentation.

17. CAPITAL MANAGEMENT

The Company's objectives when managing capital are to maintain financial stability such that it can continue to provide returns for the shareholder and benefits for other stakeholders. The Company meets its objectives for managing capital by management oversight and Board monitoring of total capital.

The Company's total capital as at December 31, consists of:

	2012	2011
Total long term liabilities	15,053,258	12,409,820
Less: cash and bank	5,733,888	3,991,761
Net long term liabilities	9,319,370	8,418,059
Total shareholder's equity	34,469,684	34,299,428
Total capital	43,789,054	42,717,487

18. FINANCIAL INSTRUMENTS

Management and the Board monitor and respond as necessary to any risks arising from financial instruments.

Fair Value

The fair value of financial instruments such as cash and bank, accounts receivable, unbilled revenue and accounts payables and accrued liabilities are determined to approximate their recorded value due to their short term maturity.

Interest Rate Risk

The Company's exposure to interest rate risk relates to its outstanding debentures (see Note 7).

Credit Risk

The Company's exposure to credit risk relates to its accounts receivable and unbilled revenue. The Company collects security deposits from customers and retailers in accordance with direction provided by the OEB. The Company held deposits of $504,221 at year end in order to mitigate credit risk.

19. CONTINGENCIES

A claim has been filed against the Company related to stray voltage. At this time, it is not possible to quantify the effect, if any, of this claim on the financial statements of the Company, consequently no provision for a loss, if any, has been recorded in these financial statements.

HALDIMAND COUNTY UTILITIES INC.

ANNUAL REPORT 2012

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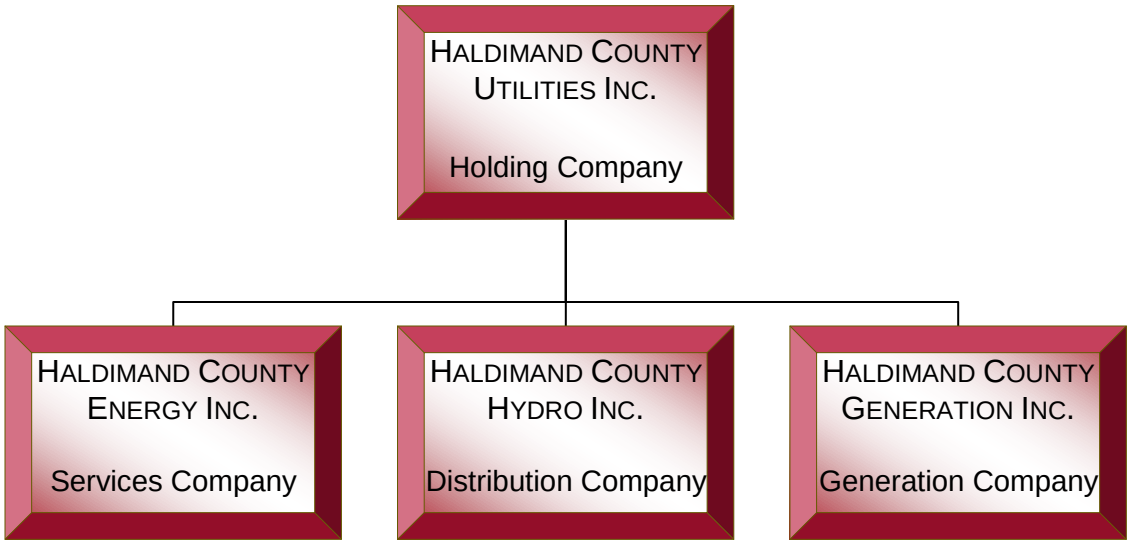
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HCUI CORPORATE STRUCTURE



Haldimand County Utilities Inc. is the Holding Company for the Distribution, Services, and Generation Companies.

The Corporation was formed in October 2000 following provincial government legislation, by amalgamating the former Hydro Electric Commissions of Dunnville, Haldimand and east portion of Nanticoke.

Haldimand County holds 100% of the shares of the Holding Company, which in turn holds 100% of the shares of each of the Distribution, Services and Generation Companies.

2012 BOARD OF DIRECTORS

Haldimand County Utilities Inc.

Albert Marshall, Chair	November 1, 2009 – Present
Councillor Tony Dalimonte, Vice Chair	October 1, 2009 – Present
Mayor Ken Hewitt	December 14, 2010 – Present
Peter D. Smuk	July 1, 2007 – Present

Haldimand County Hydro Inc.

Albert Marshall, Chair	January 1, 2007 – Present
Councillor Tony Dalimonte, Vice Chair	October 1, 2009 – Present
Mayor Ken Hewitt	December 14, 2010 – Present
Peter D. Smuk	August 24, 2005 – Present
Lorraine Bergstrand	July 1, 2011 – Present
Doug Miller	July 1, 2010 – Present
Fred Moodie	November 1, 2009 – Present
Brian Snyder	January 1, 2007 – Present

Haldimand County Energy Inc.

Albert Marshall, Chair	November 1, 2009 – Present
Councillor Tony Dalimonte, Vice Chair	October 1, 2009 – Present
Mayor Ken Hewitt	December 14, 2010 – Present
Peter D. Smuk	July 1, 2007 – Present

Haldimand County Generation Inc.

Albert Marshall, Chair	December 15, 2009 – Present
Councillor Tony Dalimonte, Vice Chair	December 14, 2010 – Present

MANAGEMENT TEAM

President & CEO	Lloyd E. Payne, P. Eng., M.B.A.
Consumer Services Manager	R. Jane Albert
Engineering Manager	Paul Heeg
Finance Manager	Jacqueline A. Scott
Operations Manager	Dan Leake, P. Eng.

Jane Albert was appointed to the position of Acting President & CEO effective January 7, 2013 in preparation for Lloyd Payne's retirement on February 1, 2013.

At its meeting held January 23, 2013, the Board for Haldimand County Utilities Inc. changed the officers of Haldimand County Utilities Inc. and its subsidiary companies to remove Lloyd Payne as President & CEO and appoint Jane Albert to this position.

Accordingly, the Message from the President & CEO will be presented by Jane Albert.

MESSAGE FROM THE CHAIR

Haldimand County Utilities Inc. mandate is the safe, reliable and efficient delivery of electrical power within its service territory, a territory third in size only to that of Hydro One's. 2012 was a successful year.

Haldimand County Hydro Inc. invested $5.4 million in capital projects in 2012. This marks our highest ever annual infrastructure investment in our community. The investments in distribution assets and technology were made with a view to our mandate. These investments in capital and ongoing maintenance programs have resulted in fewer and shorter outages.

Net income for 2012 amounted to $850,036 compared to $2,445,316 for 2011. This sharp decrease was directly attributed to the disposition of a one-time regulatory adjustment dating back to 2002. Normalized net income for 2012 (i.e. without the regulatory adjustment) is $2,050,196. The Board has chosen to declare its dividend to Haldimand County based upon our "normalized" net income in order to meet the expectation of our Shareholder.

The dividend to be paid in 2013 is $512,549. This will bring the total dividend payments to $4,898,210 since incorporation in 2000. Haldimand County has also enjoyed an increase in its shareholder's equity, which has risen from $19.1 million in 2000 to $35.2 million in 2012.

During 2011, Haldimand County Hydro Inc. finalized its second financing agreement with Ontario Infrastructure and Lands Corporation committing to borrowing $6,726,644. This brings total borrowing to $16,980,000, which was approved by the Shareholder on February 17, 2009. As of September 2012, all financing had been successfully converted to long term debentures. We are anticipating a third financing agreement in October 2013 on account of 2012 actual capital costs, and anticipated 2013 capital budget expenditures.

On March 31, 2010, the Minister of Energy and Infrastructure of Ontario directed the Ontario Energy Board (OEB) to establish Conservation and Demand Management targets to be met by electrical distributors. Accordingly, on November 12, 2010, the OEB amended Haldimand County Hydro Inc.'s distribution licence to achieve 13.3 GWh in energy savings and 2.85 MW of summer peak demand over a period beginning January 1, 2011 through December 31, 2014. At the end of 2012, Haldimand County Hydro Inc. has achieved 70% of our energy target and 21% of our demand target ranking us above average in the province. As mandated by the province of Ontario, Haldimand County Hydro Inc. provided its customers with incentives totalling $233,196 to assist them with these conservation projects.

Every five years, Haldimand County Hydro Inc. is required to file with the OEB a comprehensive Cost of Service Rate Application. The next application is due before the OEB in the Fall of 2013. This process is a major undertaking. Our team has begun to prepare this application and anticipates it being a major focus for the remainder of 2013. In addition to being mandated, this rate setting process provides predictable revenue to our distribution company and allows us to both fulfil our mandate and to provide Haldimand County, our Shareholder, with regular income.

Without a strong team we could not provide safe, reliable and efficient power. On behalf of the Board of Directors, I would like to thank the employees and executive team for all that they do. I'd also like to thank my fellow Board members for their vision and efforts throughout the year.

Albert Marshall
Chair

MESSAGE FROM THE PRESIDENT & CEO

At Haldimand County Utilities Inc. we are dedicated to serving our Customers and Shareholder in a meaningful way to meet our commitments today and into the future. We are passionate about our corporate responsibilities which are to deliver safe, reliable and efficient electricity within our community.

Most notable in 2012 is the completion of our smart meter implementation which commenced in 2006. 2012 also recognized the financial investment and ongoing operating costs which up until 2012 were reported separately. In the order of $3.8 million is attributable to the recognition of smart meter capital expenditures, in addition operating costs were increased by $800,000. The Ontario Energy Board approved the recovery of smart meter capital and operating costs incurred over an 18 month period commencing November 1, 2012. Ongoing operating costs will be part of our May 1, 2014 rates. It should be noted that our financial statements are reflecting a significant increase in asset value as compared to 2011. In 2012 our purchase of property, plant and equipment is $9.3 million whereas 2011 was $5 million.

Haldimand County Hydro Inc. delivered its operating and capital budget on target in 2012. Haldimand County Hydro Inc.'s capital investment of $5.4 million in 2012 aided the required infrastructure to support economic development and improve reliability. In 2012, we dramatically reduced the number of customer outages greater than 6 hours by 65%. We believe part of the decrease is attributed to our continuous improvement to infrastructure.

Our capital projects include: partnering with Haldimand County with the installation of an underground distribution system on Argyle Street in Caledonia and Main Street and Alder Street in Dunnville, all part of the revitalization projects within Haldimand County, as well as, a new 27.6 kV pole line from Jarvis to Townsend, and replacement of 83 end of life poles throughout the County.

Haldimand County Hydro Inc.'s residential customers made the transition to Time-of-Use rates in the last quarter of 2011. In 2012, we introduced new tools such as eCARe and a new bill print to help customers utilize their hourly electricity usage and monthly water consumption to better understand and control their costs. Customers also enjoyed the option of going "green" by choosing to view their bill on line and receiving their bill notification by email.

In 2012, we experienced zero lost time accidents. *Seriously Fun Safety* at Haldimand County Hydro Inc. is a core principle and part of every job we do. Training and awareness is an essential part of our plan to support a preventative approach where employees are empowered and supported to build a culture of "safety first". Taking the safety message into our community is a passion and commitment of ours. In 2012, 1,700 students in primary grades took part in learning about electrical safety, with more than 20,400 students during the last 12 years. This introduction can provide the structure for lifelong safety awareness.

In 2012, Haldimand County Hydro Inc. continued to experience significant customer interest and participation in renewable energy projects. The Green Energy and Economy Act, 2009, which obligates Haldimand County Hydro Inc. to provide connection access, also require the identification of the expansion of distribution system required to accommodate renewables. In 2012, microFIT (Feed-in Tariff) (≤ 10 kW) connections increased to 190 totalling 1.8 MW of generation. New in 2012, was the connection of 9 FIT (≥ 10 kW) projects totaling 1.2 MW of generation. Both microFIT and FIT projects are directly connected to our distribution system and require our direct involvement to establish connection and to financially settle with the Generators. Beyond distributed connected renewables, four large scale transmission connected generators are commencing their design and construction of the required infrastructure to accommodate 583 MW of renewable generation consisting of wind and solar. Haldimand County Hydro is involved in assisting to accommodate construction of the transmission facilities by way of new or relocated distribution facilities.

Throughout 2012, Haldimand County Hydro delivered 19 Save on Energy Conservation and Demand Management programs to our residential and business customers to meet our Ontario Energy Board mandated targets of 2.85 MW and 13.3 GWh to be achieved during 2011-2014. During 2011-2012, our customers saved 600 kW and 9.2 GWH which is enough power to provide electricity to 960 homes or 5% of our Residential customers for a year. During the same time frame, we have picked up and environmentally disposed of 427 fridges, provided incentives to 652 home owners for energy efficient air conditioning units or furnaces and upgraded lighting to 95 small businesses.

New in the spring of 2012 was the debut of the Home Assistance Program. This program is geared to customers, who without our assistance are unlikely to have the means to make changes to their lighting, weatherization or appliances. In 2012, Haldimand County Hydro Inc. retrofitted 72 households with energy saving products. Along with providing zero cost energy retrofits to low-income households, Haldimand County Hydro Inc. has partnered with Dunnville Salvation Army and Community Services to offer emergency financial assistance to help with electricity bills.

Haldimand County Hydro Inc. employees have a long standing tradition of giving back to the community. In 2012, we marked our 7th year supporting our four local food banks. In 2012, we provided 550 energy saving kits along with employee food donations to be included with the annual Christmas food hampers. A total of 3270 families have been provided with assistance over the last seven years. A new initiative in 2012 included our employees partnering with the Dunnville Salvation Army and Community Services to raise money to send six deserving children to summer camp including all their gear.

Creating great outcomes can only be accomplished with focus, dedication and commitment to excellence. I would like to congratulate each of our employees for their contributions and serving our customers and community with such pride. I would also like to thank the Board of Directors for their support and leadership that drives us to be our best.

R. Jane Albert
President & CEO

MANAGEMENT DISCUSSION AND ANALYSIS

The following discussion and analysis should be read in conjunction with the Consolidated Financial Statements, related Note disclosures and Auditor's Report, as at and for the year ended December 31, 2012. The Consolidated Financial Statements are prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"), including accounting principles prescribed by the Ontario Energy Board in its "Accounting Procedures Handbook". The financial statements were approved by the Board of Directors on April 3, 2013. This discussion may contain forward looking statements that are subject to risks, uncertainties and assumptions based on information available as at the date of this report. Management does not intend to update this information and disclaims any legal obligation for actual results that vary from those implied.

HALDIMAND COUNTY UTILITIES INC.

In response to the restructuring and deregulation of Ontario's electricity industry, and pursuant to the *Energy Competition Act (Ontario), 1998* (the "Electricity Act"), Haldimand County Utilities Inc. (the "Corporation") was incorporated under the Ontario Business Corporations Act.

The hydro-electric commissions of the former municipalities of Haldimand and Dunnville and divided City of Nanticoke transferred at book value, their assets and liabilities to the Corporation, effective November 1, 2000. The sole shareholder of the Corporation is the Municipality of Haldimand County (the "Municipality"). The Municipality has the power to determine the composition of the Board of Directors of the Corporation and influence the Corporation's major business and corporate decisions.

The Electricity Act and its enabling regulations distinguish between, and require the separation of, regulated electricity businesses from non-regulated business activities. The Corporation is a holding company, which wholly owns and provides strategic direction to the following subsidiaries:

- Haldimand County Hydro Inc. ("HCHI"), a local distribution company ("LDC"), which distributes electricity to residents and businesses within the Municipality.

- Haldimand County Energy Inc. ("HCEI"), which provides non-regulated water and sewer billing, collecting, and customer care services to the Municipality, as well as sentinel light rentals to its customers.

- Haldimand County Generation Inc. ("HCGI"), which is currently an inactive company.

The principal business of the Corporation and its subsidiaries is the regulated distribution of electricity by HCHI. The Consolidated Financial Statements include results for both the regulated and non-regulated business activities of its subsidiaries. The electricity distribution business of the Corporation represented approximately 99% (2011 - 99%) of consolidated assets and 99% (2011 - 99%) of consolidated revenue and other income at year-end.

HALDIMAND COUNTY HYDRO INC.

HCHI owns and operates $45.0 million (2011 - $39.8 million) of capital assets comprised primarily of an electricity distribution system, which delivers safe, reliable and cost-effective electricity to approximately 21,200 residential and business customers located in the Municipality, which has a population base of approximately 45,000, covering a service territory of 1,252 square kilometres. HCHI plans, maintains and operates the Municipality's electrical distribution system infrastructure efficiently and in an environmentally responsible manner, while providing consistent, high quality customer service.

Electricity produced at generating stations is transmitted along transmission lines to transformer stations which include power transformers and high-voltage switching equipment – all owned by Hydro One Networks Inc. ("Hydro One") – at which point the voltage is then reduced (or stepped down) to the distribution-level voltage 27.6 kV. Electricity is then distributed across HCHI's distribution system to both end use customers and distribution substations at which point the voltage is further reduced (or stepped down) to 8.3 kV for supply to end use customers. HCHI's distribution system, which is serviced from 3 transformer stations, includes 5 distribution substations that are used to reduce (or step down) voltage prior to the delivery to 7,259 distribution transformers, through a network comprised of 1,652 road kilometres of overhead lines supported by 27,931 poles and 96 circuit kilometres of underground lines. HCHI provides its customers with meters through which electricity passes before reaching a service panel that direct the electricity to end use circuits on the customer's premises. The meters are used to measure electricity consumption. HCHI owns the meters and is responsible for their maintenance and accuracy.

Although distribution systems were traditionally designed to supply load customers, smaller generators are increasingly connecting directly to the distribution system encouraged by government sponsored programs. As at December 31, 2012, 203 generators (2011 – 154) were connected to HCHI's distribution system with an installed capacity of 19,153.74 kW (2011 – 17,530.88 kW).

HCHI's distribution system serves most of the residents and businesses within the borders of the Municipality. At the end of 2012, HCHI supplied 119 customers outside its service territory for other distributors. Such customer supply arrangements are referred to as "long term load transfers", and the Ontario Energy Board (the "OEB"), in accordance with their Distribution System Code, has proposed such arrangements be eliminated before June 30, 2014.

Electricity Consumption

The Corporation earns revenue by charging its customers for the use of the distribution system. Such electricity distribution charges are comprised of a fixed monthly service charge combined with a variable (volumetric) charge based on electricity consumption (usage). The distribution rate charged is designed to recover the costs incurred by HCHI in delivering electricity to customers and a rate of return on deemed common equity, which is subject to the approval of the OEB.

2012 Customers, Consumption and Distribution Revenue by Rate Class

Rate Class	No. of Customers	Consumption (kWh)		Distribution Revenue ($)	
			%		%
Residential	18,640	168,308,353	40.4	$ 9,896,943	69.0
General Service < 50 kW	2,371	56,019,870	13.5	$ 2,155,082	15.0
General Service 50 kW to 4999 kW	147	117,120,197	28.1	$ 1,691,121	11.8
Embedded Distributor	8	71,831,928	17.2	$ 156,499	1.1
Sentinel Lighting *		361,875	0.1	$ 124,546	0.9
Street Lighting *	3	2,398,127	0.6	$ 300,770	2.1
Unmetered Scattered Load *	71	389,982	0.1	$ 18,269	0.1
Total	**21,240**	**416,430,332**	**100.0**	**$ 14,343,230**	**100.0**

* Sentinel Lights, Street Lights and Unmetered Scattered Loads are billed based on number of "connections", at 535, 2,988 and 73 respectively

2012 Average Electricity Consumption per Customer by Rate Class

	kWh per Month	kWh per Year
Residential	752	9,029
General Service < 50 kW	1,970	23,637
General Service 50 kW to 4,999 kW	66,395	796,736

2012 Purchased Consumption

	kWh	%
Provincial Grid (IESO)	407,219,216	92.5%
Distribution-connected Generators	33,130,989	7.5%
Total	**440,350,205**	**100.0%**

2012 System Coincident Peak Demand

83.93 MW on July 6, 2012 at 17:00 hours EST

ELECTRICITY DISTRIBUTION REGULATION

HCHI is a regulated utility and must comply with the requirements of the provincial regulator, the OEB. The OEB has regulatory oversight of electricity matters in the Province, which includes the power to issue a distribution licence, mandatory for any entity owning or operating a distribution system. The OEB may prescribe licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, separation of accounts for affiliate businesses and filing/process requirements for rate-setting purposes.

The *Ontario Energy Board Act, 1998* (the "Ontario Energy Board Act") gave the OEB increased powers and responsibilities, including the power to approve or fix rates for the transmission and distribution of electricity, and the responsibility for ensuring that distribution companies fulfill obligations to connect and service customers.

As a participant in the electricity market, HCHI must also comply with rules of the Independent Electricity System Operator (the "IESO"). The IESO is responsible for overseeing and operating the wholesale market as well as ensuring the reliability of the integrated power system. HCHI must also adhere to Regulation 22/04 of the Ontario Electrical Safety Act.

BILLINGS TO ELECTRICITY CUSTOMERS

Pursuant to industry regulation, HCHI is required to be the default billing and collecting agent for all electricity related charges for all electricity participants, which, in addition to its own electricity distribution service charges, includes:

- *Electricity Price* – the commodity cost of electricity, settled through the IESO, accruing to generators such as the provincially owned Ontario Power Generation Inc. ("OPGI"). The commodity cost of energy for certain low-volume and designated customers is based on the OEB's Regulated Price Plan ("RPP"). Unexpected shortfalls or overpayments associated with the RPP are temporarily financed by the Ontario Power Authority ("OPA"). Prices are reviewed every six months and may change based on an updated OEB forecast and any accumulated difference between the amount that customers paid for electricity and the amount paid to generators in the previous period. Customers who are not eligible for the RPP and wholesale customers pay the market price for electricity, and

pay a Global Adjustment for the difference between the market price and set prices paid to certain regulated and contract generators.

- *Retail Transmission Service Rates ("RTSRs")* – wholesale costs incurred by distributors in respect of transmission of electricity from generating stations to local areas. Retail transmission service rates are regulated by the OEB.

- *Wholesale Market Service Charge ("WMS")* – wholesale market support costs charged to market participants such as the IESO fees and uplift charges. These charges are also regulated by the OEB.

- *Debt Retirement Charge ("DRC")* – provincial charge directed to the repayment of the stranded debt obligations of the former Ontario Hydro, which continue in the Ontario Electricity Financial Corporation (the "OEFC"), an agency of the Ontario government.

- *Harmonized Sales Tax ("HST")*

These other non-distribution charges, represent "pass through" charges and the Corporation must remit them to other industry participants regardless of whether such charges are ultimately collected by HCHI from its customers. With the exception of the DRC and HST, LDCs are exposed to losses for entire amounts billed to customers. The carrying amount of accounts receivable is reduced through an allowance for doubtful accounts and the amount of the related impairment loss is recognized in the consolidated statement of income. Subsequent recoveries of accounts receivable previously written off are credited to the consolidated statement of income. Management estimates uncollectible accounts receivable after considering historical loss experience and the characteristics of existing accounts. The balance of the allowance for impairment as at December 31, 2012 is $200,000 (December 31, 2011 - $207,000).

In 2012, approximately 78% of charges, including DRC, billed to customers flowed through at cost on behalf of other market participants (2011 – 77%). The remaining 22%, representing distribution service charges regulated by the OEB, was retained by HCHI to operate the distribution system (2011 – 23%).

PRUDENTIAL AND CREDIT SUPPORT

As a market participant, HCHI is required to satisfy and maintain prudential requirements with the IESO, which include credit support with respect to outstanding market obligations in the form of a letter of credit.

HCHI collects cash and cash equivalent deposits, in accordance with direction provided by the OEB, from certain customers and retailers of electricity to reduce credit risk with respect to non-payment of electricity bills. Deposits from electricity distribution customers are applied against any unpaid portion of individual customer accounts. Customer deposits in excess of unpaid account balances are refundable to individual customers upon termination of their electricity distribution service. As at December 31, 2012, HCHI held security deposits in the amount of $501,000 (2011 - $473,000). It is also the policy of the Corporation to apply late payment interest at OEB-approved rates, require pre-authorized payment under certain conditions and discontinue service for non-payment of customer accounts.

GREEN ENERGY ACT

Bill 150, the *Green Energy and Green Economy Act, 2009* (the "Green Energy Act"), was enacted on May 14, 2009. The Green Energy Act, among other things, (i) permits electricity distribution companies to own renewable generation facilities, (ii) obligates electricity distribution companies to provide priority connection access for renewable generation facilities and to prepare plans that identify expansion or reinforcement of the distribution system required to accommodate these connections, for approval by the OEB as well as assigning cost responsibility between a distributor and a generator, (iii) empowers the OEB to set conservation and demand management ("CDM") targets for electricity distribution companies as a condition of licence, and (iv) requires electricity distribution companies to accommodate the development and implementation of a smart grid in relation to their systems.

Conservation and Demand Management

On March 31, 2010, the Minister of Energy directed the OEB to establish CDM targets to be met by LDCs. Accordingly, on November 12, 2010, the OEB amended HCHI's distribution licence to require HCHI, as a condition of its licence, to achieve 13.3 GWh of energy savings and 2.85 MW of summer peak demand savings, over the period beginning January 1, 2011 through December 31, 2014.

On February 4, 2011, HCHI entered into a Master CDM Agreement (the "Agreement") with the OPA to deliver OPA-funded programs in the amount of $1,403,336 from January 1, 2011 to December 31, 2014 – in support of achieving its mandatory CDM targets. Subject to the terms of the Agreement, all programs to be delivered are fully funded through the Global Adjustment mechanism and paid in advance by the OPA. HCHI acts as a delivery agent for those programs that it participates in under the Agreement. As at December 31, 2012, HCHI received approximately $546,000 (December 31, 2011 - $299,000) from the OPA for delivery of CDM programs. Amounts received but not yet spent are presented under current liabilities as accrued expenses. Upon the expiration of the agreement, HCHI is required to repay to the OPA any excess funding received for program administration less any cost efficiency incentives. Any administration costs in excess of the pre-approved estimate would not be recoverable. All other program costs incurred by HCHI, such as customer incentives and goods and services delivered under the programs, are recoverable from the OPA on an invoiced basis. HCHI can earn revenue by meeting and/or exceeding its targets and/or delivering programs below the fixed funding level. Unverified results for 2012 indicate that HCHI has reached 70.0% of its energy target and 21.1% of its demand target.

On December 21, 2012, the Minister of Energy issued a direction to the OPA to extend the funding time period for OPA-contracted province-wide CDM initiatives under the Green Energy Act framework to December 31, 2015.

Smart Meters and Time-of-Use Electricity Rates

The Province of Ontario committed to having smart meters installed in all homes and small businesses throughout Ontario. These meters are capable of measuring and reporting usage over predetermined periods, being read remotely, and when combined with communications systems are capable of providing customers with access to information about their consumption. LDCs, including HCHI, were accountable for the development of smart meter infrastructure and related technology for communications to meet minimum requirements as defined in regulations, as well as the implementation of time of use ("TOU") rates. On August 4, 2010, the OEB mandated HCHI's TOU rates be implemented in September 2011. 21,000 customers were being charged TOU rates as at December 31, 2012 (December 31, 2011 – 20,504).

HCHI has completed this project, having installed 21,011 smart meters as at December 31, 2012 (December 31, 2011 – 20,906). Efforts continue with respect to integrating the Operational Data Store (the "ODS") which serves to warehouse the large quantity of data collected used for billing purposes and operational needs, via the Advanced Meter Infrastructure ("AMI") system, and the Geographical Information System ("GIS"). The OEB directed LDCs to record all expenditures and related revenues from 2008 to 2012 in deferral accounts, and allowed LDCs to keep the net book value of the stranded meters in property, plant and equipment. These expenditures had been funded through a utility-specific Smart Meter Funding Adder ("SMFA") in accordance with the "Smart Meter Funding and Cost Recovery Guideline" of the OEB.

In December 2011, the OEB issued its "Guideline for Smart Meter Funding and Cost Recovery Final Disposition", which set out the OEB's filing requirements in relation to the funding of, and the recovery of costs associated with, smart meter activities conducted by LDCs.

On July 18, 2012, HCHI submitted its Smart Meter Application seeking OEB approval for the disposition and recovery of costs related to smart meter deployment – in the amount of $4.5 million including both capital expenditures and operating expenses – offset by SMFA revenues collected from May 1, 2006 to April 30, 2012 – in the amount of $1.4 million. The OEB approved these costs, as applied for, which resulted in the following two rate riders:

- A Smart Meter Disposition Rider ("SMDR") over an 18 month disposition period from November 1, 2012 to April 30, 2014, to recover (i) the deferred revenue requirements related to smart meters deployed as at December 31, 2011, net of the smart meter funding adder collected from May 1, 2006 to April 30, 2012 specific to each applicable rate class and (ii) foregone revenue to recover six months of the 2012 incremental revenue requirement not recovered commencing May 1, 2012 to November 1, 2012; and
- A Smart Meter Incremental Revenue Requirement Rate Rider ("SMIRR") to recover the annual revenue requirements associated with smart meters installed for each applicable rate class from the inception of the smart meter program, to be in effect until HCHI's next cost of service application when smart meter capital and operating costs will be incorporated into the rate base and revenue requirement.

Renewable Energy Generation

The OPA launched the much-anticipated Feed-in Tariff (the "FIT") program and began accepting FIT applications on October 1, 2009. The FIT program provides for 20 year contracts (40 years for waterpower) offering price guarantees for energy generated from renewable energy sources, including solar, wind, biogas, biomass, landfill gas and hydro. Applications for new projects were suspended in October 2011 as the OPA was undertaking a FIT Program Review to develop new rules and prices. Projects with applications previously approved continued. During 2012, 9 FIT (i.e. greater than 10 kW but less than 500 kW) projects totaling 1,161 kW were connected to HCHI's distribution system. During 2012 an additional 38 microFIT (i.e. less than or equal to 10 kW) PV-solar projects were connected totaling 367.46 kW of installed capacity (2011 – 115 additional projects totaling 1,114.08 kW). As at December 31, 2012, a total of 190 microFIT projects were connected to HCHI's distribution system, totaling 1,817.74 kW of installed capacity. Each of the FIT and microFIT generators requires settlement through HCHI's billing system.

Four large scale, transmission connected, wind and solar developers' projects continue to impact HCHI with respect to their construction in the Municipality. Two projects commenced during 2012, requiring HCHI to build distribution lines to connect station services to the Hydro One switching stations as well as to the project's own transformer station.

REGULATORY ASSETS AND LIABILITIES

In its approval to set rates, the OEB has the authority to specify regulatory treatments that may result in accounting treatments that differ from Canadian generally accepted accounting principles for enterprises operating in a non-rate regulated environment. The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. Regulatory assets represent costs that have been deferred for accounting purposes because it is probable that they will be recovered from customers in future rates. Regulatory liabilities represent future reductions in revenue associated with costs that are expected to be refunded to customers through rates. The Corporation's regulatory assets as at December 31, 2012 amounted to approximately $6,200 (December 31, 2011 - $4.6 million). Regulatory liabilities as at December 31, 2012 amounted to approximately $2.1 million (December 31, 2011 - $2.3 million). Both the regulatory assets and regulatory liabilities relate to retail settlement variances; that is, comprised of the variances between amounts charged by HCHI to customers, based on regulated rates, and the corresponding cost of non-competitive electricity service incurred by HCHI. In the event that the disposition of these balances was no longer

deemed to be probable, the balances would be reported in the Corporation's consolidated results of operations. The regulatory assets and liabilities are further discussed in Note 6 accompanying the Consolidated Financial Statements.

Combined PILS Proceeding

The OEB conducted a review of the Deferred Payments in Lieu of Taxes ("Deferred PILs") variances accumulated in regulatory variance accounts for the period from the introduction of PILs on October 1, 2001 to April 30, 2006 for three participating LDCs. On June 24, 2011, the OEB issued its decision for these LDCs and provided guidelines for the calculation and further disposition of the balances accumulated in the PILs regulatory variance accounts.

HCHI had reviewed the balance of its Deferred PILs regulatory variance accounts and had applied the guidelines previously provided by the OEB. As at December 31, 2011, HCHI's balance was a debit amount $1,008,852. HCHI applied on January 27, 2012 for disposition of this balance. As part of the interrogatory phase, OEB staff provided revised PILs models – including adjustments made throughout the proceeding – and corresponding revised account 1562 Deferred PILs continuity schedules that they believe conform with the various decisions related to the Deferred PILs issues. Effectively the OEB's proceeding with the participating utilities established an updated interpretation on its regulations. The OEB's decision clarified (i.e. established) the accounting treatment of account 1562 and set a consistent methodology that the OEB has adopted for other utilities, including HCHI.

The application of the clarified rules and subsequent OEB decision resulted in an accounting change for HCHI. In accordance with the OEB's decision and order with respect to HCHI's disposition application, the Deferred PILs balance was revised to a disposition credit amount of $705,923 – requiring a total credit adjustment to the Deferred PILs account in the amount of $1,724,427. The offsetting debit amount, net of the future tax impact of the adjustment in the credit amount of $524,267, has been reported as a current period regulatory adjustment in the amount of $1,200,160 in the Statement of Income for the year ended December 31, 2012. The refund to customers on account of this disposition is through a credit rate rider effective October 1, 2012 over a 19 month disposition period ending April 30, 2014.

ELECTRICITY DISTRIBUTION RATES

Electricity rates charged by an LDC are regulated by the OEB, using a combination of annual incentive rate mechanism ("IRM") adjustments and periodic cost of service reviews, based upon applications made by the LDC to the OEB. Currently, the ratemaking policy of the OEB requires a cost of service review every four years, which is followed by three successive years of IRM adjustments.

On October 18, 2012, the OEB issued its "Report of the Board – A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach" (the "RRFE" Report). The RRFE Report provides a comprehensive performance-based approach to regulation that is based on the achievement of outcomes and identifies three main policies: rate setting; planning and measuring performance. With respect to rate setting, LDCs will be permitted to choose from among three rate setting methods: 4th Generation Incentive Rate Setting, Custom Incentive Rate Setting, or Annual Incentive Rate Setting Index.

- The 4th Generation Rate Setting method is similar to the current IRM rate setting process. The most significant difference is that the term of annual incentive rate adjustments between cost of service reviews is four years; that is, an additional year to the current process.
- Custom Incentive Rate Setting permits LDCs to base their rates on a five year forecast of revenue requirement and forecast load, with expected inflationary and productivity-based estimates included as components of the resulting rate adjustments. This method will be suitable for LDCs with large multi-year or highly variable capital investment.
- Annual Incentive Rate Setting index will adjust rates by a price cap index formula and there will be no fixed term. This model allows LDCs to avoid cost of service reviews. This method will be appropriate for LDCs operating with relatively stable investment levels; however, the productivity factor will be the same as the highest set for the 4th Generation method.

The cost of service framework sets electricity distribution rates using a detailed examination of evidence and an assessment of costs, based on forecast test year data, including the amount of operating and capital expenses, debt and shareholder's equity required to support an LDC's business. The aggregate amount of debt and equity upon which an LDC may recover interest charges and a maximum allowable return on equity is equal to the rate base of an LDC. Rate base is determined as the aggregate of fixed distribution assets and a working capital allowance. The OEB's prescribed return on equity assumes a deemed capital structure of 60% debt and 40% equity.

The IRM process provides for a mechanistic and formulaic adjustment to distribution rates and charges between cost of service applications. IRM adjustments are based on the annual change in the Gross Domestic Product Inflationary Price Index for Final Domestic Demand ("GDP-IPI") net of a productivity factor and a "stretch factor" determined by the relative efficiency of an electricity distributor.

LDC electricity distribution rates are typically effective from May 1 to April 30 of the following year. Accordingly, for the first four months of 2012, distribution revenue was based on rates approved for the May 1, 2011 to April 30, 2012 rate year (the "2011 rate year"), and the distribution revenue for the remainder of 2012 was based on rates approved for the May 1, 2012 to April 30, 2013 rate year (the "2012 rate year").

HCHI's electricity distribution rates for the 2010 rate year were determined through an application under the cost of service framework and approved by the OEB on March 31, 2010, with rates effective May 1, 2010. This approval provided for a distribution revenue requirement of $12,646,747 and rate base of $40,215,214. The 2010 rate year also included recovery of lost revenue and shared savings, in the combined amount of $391,337, related to HCHI's CDM programs delivered in 2005 through 2007.

In November 2010, HCHI submitted its IRM application for the 2011 rate year. As a result of this filing, on March 31, 2011 the OEB approved an electricity distribution rate adjustment of 0.18% uniformly across all customer classes, with rates effective May 1, 2011. The decision by the OEB also provided approval for the disposition of an aggregate regulatory assets/liabilities credit balance of $534,813 over a one year period.

Similarly, in September 2011, HCHI submitted its IRM application for the 2012 rate year. As a result of this filing, on April 4, 2012 the OEB approved an electricity distribution rate adjustment of 0.88% uniformly across all customer classes. The decision by the OEB also provided approval for the disposition of an aggregate regulatory assets/liabilities credit balance of $1,356,288 over a one year period.

HCHI is scheduled to file its next comprehensive cost of service rate application by October 1, 2013 for rates to be effective May 1, 2014. The ability to maintain the distribution system in the future depends on, among other factors, the OEB allowing recovery of the operating, maintenance and capital costs required in the future.

ADOPTION OF NEW ACCOUNTING STANDARDS

Government Business Enterprises in Canada were required to adopt International Financial Reporting Standards ("IFRS") (part I of the CICA Handbook) in place of Canadian GAAP (part V of the CICA Handbook) for annual reporting purposes for fiscal years beginning on or after January 1, 2011. On September 10, 2010, the Accounting Standards Board ("AcSB") granted an optional one-year deferral of IFRS adoption for entities subject to rate regulation due to the uncertainty in regards to rate regulated accounting; and as such, rate regulated entities may adopt IFRS for financial statements ending December 31, 2012. Subsequently, the AcSB has allowed additional deferrals of the mandatory adoption of IFRS for fiscal years beginning January 1, 2015 for Canadian utilities with qualifying rate-regulated activities. The Corporation has taken the deferrals and will continue to assess the impact of conversion to IFRS on its results of operations, and how any changes will impact on its reporting under IFRS.

RESULTS OF OPERATIONS

Year Ended December 31, 2012 compared to Year Ended December 31, 2011

Results of Operations		
For the year ended	**2012**	**2011**
Revenues	$ 15,707,206	$ 14,300,776
Expenses	$ 12,945,560	$ 10,870,468
Income before Income Taxes and Regulatory Adjustment	$ 2,761,646	$ 3,430,308
Income Taxes	$ 711,450	$ 984,992
Income before Regulatory Adjustment	**$ 2,050,196**	**$ 2,445,316**
Regulatory adjustment - PILs, net of tax	$ 1,200,160	$ -
Net Income	**$ 850,036**	**$ 2,445,316**

Income before Regulatory Adjustment was $2,050,196 in 2012 compared to $2,445,316 in 2011 – a net decrease in the order of $400,000. Revenues increased approximately $1.4 million; however, this was offset by an increase in total operating expenses of approximately $2.1 million.

These net changes in revenues and operating expenses are primarily due to the accounting for smart meters in 2012. The issuance of the Board Order approving the smart meters investment and associated (net) revenue requirement for the smart meters in rates, as noted above, triggers the accounting recognition of the investment in smart meters as assets and the funding received for the smart meters as revenues. Consequently, this required the accounting reclassification of these items previously recorded in the OEB directed variance accounts to their applicable balance sheet and income statement accounts.

Accordingly, the "Income before Income Taxes and Regulatory Adjustment" decreased in the order of $700,000. The provision for income taxes, including current and future taxes, was similarly reduced, in the order of $300,000.

The "Regulatory Adjustment – PILs, net of tax" was discussed above in the "*Combined PILs Proceeding*" section.

REVENUE

Revenues		
For the year ended	**2012**	**2011**
Distribution Services	$ 14,343,230	$ 12,875,589
Other Operating Revenue	$ 1,363,976	$ 1,425,187
	$ 15,707,206	**$ 14,300,776**

Distribution Services Revenue

Distribution Services revenue was $14,343,230 in 2012 compared to $12,875,589 in 2011 – a net increase in the order of $1.4 million. An increase of approximately $1.6 million is attributable to the recognition of smart meter revenues in 2012. A decrease of approximately $200,000 is attributable to a reduction in consumption across all rate classes in 2012.

The volume of electricity consumed by HCHI's customers during any period is dictated by events largely outside of its control, including sustained periods of severe weather, general economic conditions and unpredictable effects of CDM. Accordingly, there can be no assurance that HCHI will earn the revenue requirement approved by the OEB. The distribution rates allowed by the OEB are based on a fixed and variable volumetric charge. Differences from normal weather patterns and conservation efforts affect customer consumption, and therefore variable distribution revenue, in both a positive or negative way.

Revenue Recognition

Revenue from the sale of electricity is recorded on the basis of cyclical billings and also includes unbilled revenue accrued in respect of electricity delivered but not yet billed. HCHI uses estimates for determining the amount of energy consumed and not yet billed due to the timing differences between the billing dates and meter read dates, and the difference between billing dates and financial statement dates. Estimates are used in an attempt to match the cost of power expense, which is billed on a monthly basis, to electricity related revenue, which is based on meter reading periods that may straddle two months. Services and other operating revenue are recognized as services are rendered.

Other Operating Revenue

Other operating revenue was $1,363,976 in 2012 compared to $1,425,187 in 2011 and this represents a decrease in the order of $61,000. This decrease is primarily on account of the reversal of carrying charges related to the smart meter capital expenditure and operating expense deferral accounts recognized in 2012. Other operating revenue includes various sources of revenue as listed in Note 10 accompanying the Consolidated Financial Statements.

EXPENSES

Expenses		
For the year ended	**2012**	**2011**
Operating Expenses	$ 8,470,292	$ 7,407,233
Amortization	$ 3,939,675	$ 2,977,734
Interest Expense	$ 535,593	$ 485,501
	$ 12,945,560	**$ 10,870,468**

Operating Expenses

Operating expenses include Distribution, Billing and Collecting, General Administration and Directors. Operating expenses were $8,470,292 in 2012 compared to $7,407,233 in 2011 – a net increase in the order of $1.1 million. Approximately $800,000 of this increase is attributable to the recognition of smart meter expenses in 2012.

Significant operating activities, including departmental projects contributing to these expenses, include the following:

a) HCHI continued with its Distribution System Maintenance and Inspection program in 2012. HCHI remains focused on reliability while recognizing the challenges in operating a distribution system with low customer density and rural geography. Maintenance was carried out while also managing the impact of electrical disturbances. Significant maintenance activities included overhead switch maintenance, thermography inspection, distribution station maintenance and hydraulic recloser maintenance.

b) HCHI has committed to the identification and removal of PCB contaminated transformers from its distribution system. In 2012, 40 of these transformers (2011 – 26) were removed from service. As at December 31, 2012, HCHI has 13 PCB transformers remaining in the system. This removal activity will continue over the next year with the intent of eliminating PCB equipment from HCHI's service territory by the end of 2013.

c) The OEB regulates plant inspections as a requirement for all LDCs. Urban areas are done on a three year cycle and rural areas on a six year cycle. HCHI's program in 2012 concentrated on the rural area of the former Townships of North and South Cayuga and Rainham. This work includes the immediate repair of deficiencies accessible from the ground, wood pole integrity testing where required, and capturing GPS coordinates for each new pole location not captured during previous inspections. Major deficiencies are noted for further engineering work and the GPS coordinates are used to plot each pole on HCHI's mapping and geographical information system ("GIS").

d) As part of a planned five-year cycle, line clearing of trees continued in 2012. This work concentrated on the rural area of the former Townships of Oneida and Seneca. Other specific areas where growth exceeded the five year schedule were also cleared. This program continues to be very effective in reducing tree-related outages.

e) HCHI currently has five operating distribution substations (DSs) and one regulating station (RS) in service. A part of the Corporation's long-term plan is to remove DSs from service by converting the service territory to 27.6 kV. As stations are removed from service the sites are screened for contaminants and remediated accordingly.

i. The former Selkirk North DS, Caledonia (removed from service in late 2009) site was remediated in 2011. The Record of Site Condition ("RSC") was acknowledged by the Ministry of Environment ("MOE") on April 19, 2012. The sale of this property closed in November 2012.
ii. The former Nanticoke DS (removed from service in 2008) site was tested and remediated in 2010. The RSC was acknowledged by the MOE on June 2, 2011. The sale of this property closed in December 2012.
iii. The former Forest Street DS, Dunnville (removed from service in 2006) site was tested and remediated in 2010. The RSC was acknowledged by the MOE on September 2, 2010. Disposal of this property is underway and continues into 2013.

f) Dissolved gas in oil analysis on all substation transformers was completed as part of the annual maintenance program. A number of these units are being monitored for moisture content. Moisture removal in the most severe cases began in the spring of 2012 with the use of a portable moisture removal system acquired for this purpose. HCHI also completed transformer oil maintenance based on oil testing results at the Selkirk South DS, Jarvis DS and Decewsville RS during 2012.

g) In 2006 HCHI embarked on an effort to recycle and rebuild transformers to fulfill current and future requirements; that is, using parts of old units to build new units. This program continues to lower the purchase cost of transformers (compared with new units) and promotes environmental stewardship as it reuses materials that would normally enter the waste stream.

Weather plays an important role in the operations of the utility. Severe weather conditions increase the likelihood of customer outages that affect operating costs. This is managed through such programs as the annual tree trimming program and infrared surveys of plant and equipment and by maintaining an adequate inventory of replacement parts.

The potentially hazardous nature of our business requires a strong focus on safety, which continued to be a top priority in 2012. During 2012, half of our Lineperson staff completed the first part of a two-year proficiency training course led by the Infrastructure Health and Safety Association (the "IHSA").

Customer service activities in 2012 were focused on communications, including the launch of a revised corporate website and mobile device application. *eCARe*, a customer web-based service to display TOU and other account data, was also introduced to customers in conjunction with e-billing options.

Human Resources

As at December 31, 2012 the Corporation's workforce consisted of 51 unionized and non-unionized employees (2011 – 48), for a combined gross payroll, including employer portions of source deductions, employee group health benefit premiums, and pension contributions in the order of $4.4 million (2011 - $4.2 million). The Corporation provides a pension plan for its employees through OMERS. The plan is a multi-employer, contributory defined benefit pension plan with equal contributions by the employer and its employees. In 2012, the Corporation made employer contributions of $279,000 to OMERS (2011 - $231,000).

There were three new staff positions created during 2012 (2011 – 0), including a (i) Sync Operator (March); (ii) Distribution Engineer (September) and (iii) Lineperson Apprentice (November). A Customer Service and Collections Clerk position, which was vacated during 2011 due to a maternity leave and filled temporarily under contract, was permanently filled in April 2012. An Engineering Technician position was vacant at the end of the year and was filled in January 2013. During 2012, the President & CEO announced his retirement to be effective February 1, 2013 and the replacement for this position was appointed in an acting capacity in January 2013.

The bargaining unit employees are represented by the International Brotherhood of Electrical Workers ("IBEW") Union, operating under a four year collective agreement, effective April 1, 2009 to March 31, 2013. In addition to the new staff positions, increased payroll costs are a function of the scheduled 2% across the board wage increase effective April 1, 2012, and the 1% increase effective October 1, 2012 for all union and non-union employees.

Amortization

Amortization expense was $3,939,675 in 2012 compared to $2,977,734 in 2011 – a net increase in the order of $1.0 million. Approximately $800,000 of this increase is attributable to the amortization on account of the recognition of smart meter capital expenditures during 2012. The remaining increase of approximately $200,000 was due to amortization related to new asset additions in service in 2012 and recognized in net income on a straight-line basis over the estimated useful life of the asset.

Capital Expenditures

In the order of $3.8 million is attributable to the recognition of smart meter capital expenditures during 2012. The remaining increase is attributable to the placement of new assets in service, consistent with our ongoing capital works program including new projects, services, line extensions, routine replacement and enhancements of aging infrastructure, tools, shop and transportation equipment, and general administrative assets, net of capital contributions, in the order of $5.4 million (2011- $4.9 million). The cost of self-constructed assets includes contracted services, materials and transportation, direct labour and directly attributable overhead costs, required to bring the asset to a working condition for its intended use.

Capital Expenditures Net of Capital Contributions

For the year ended	2012	2011
Distribution Plant Assets	$ 8,504,301	$ 4,203,344
Tools, Shop and Transportation Equipment	$ 273,983	$ 320,348
General Administration Assets	$ 377,290	$ 404,002
Sentinel Light Rental Units	$ 2,259	$ 2,524
Total	**$ 9,157,833**	**$ 4,930,218**

Capital Contributions

Capital contributions arise from new connection charges which are provided and paid by developers and/or customers and used to finance additions to capital assets. Capital contributions received are treated as a "credit" contra account and are included in capital assets. These amounts are subsequently amortized by a charge to accumulated amortization and a credit to amortization expense at an equivalent rate to that used for the amortization of the related capital asset.

In 2012, net capital expenditures provided for the rebate of capital contributions, in the order of $54,000 (2011- $13,000), to developers on account of eligible subdivision agreements entered into after November 2000. The rebates are calculated using an economic evaluation model developed in accordance with the OEB's Distribution System Code.

Interest Expense

Interest expense was $535,593 in 2012 compared to $485,501 in 2011 – a net increase in the order of $50,000. This increase is on account of the long-term debenture financing in the total amount of $6.7 million issued during 2012 as discussed below.

Payments in Lieu of Taxes

The Corporation is currently exempt from taxes under the Income Tax Act (Canada) and the Corporations Tax Act (Ontario). However, the Corporation and each of its subsidiaries is a "municipal electric utility" ("MEU") for purposes of the payments in lieu ("PILs") regime contained in the *Electricity Act, 1998*. Accordingly, the Corporation makes payments in lieu of corporate income taxes to the OEFC (to be applied against certain debt obligations of the former Ontario Hydro). The Corporation provides for PILs using the asset and liability method. Under this method, future income taxes reflect the net tax effects of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes.

FUNDS GENERATED FROM OPERATIONS

Cash and cash equivalents was $5,733,889 in 2012 compared to $3,991,762 in 2011. The increase in the order of $1.7 million is due to the increase in cash flows from operating activities and long-term debt which exceeded the decrease in cash flows from the investment in capital assets.

The Corporation's primary sources of funding for capital expenditures are cash provided by operating activities, interest income and long-term debt financing. HCHI's liquidity and capital resource requirements are mainly for capital expenditures to maintain and improve the electricity distribution system, purchased power expenses, financing charges, prudential requirements, and dividends.

As expected during the 2011 capital budget process, cash generated from operations, after the expected dividend payment, was not sufficient to fund capital expenditures. In July 2011 a new financing agreement with OILC was entered into for $6.7 million secured against a combination of capital expenditures completed in 2010 and 2011. An advance in the form of short-term construction financing, in the amount of $3.2 million was received in August 2011. The Corporation converted this existing short-term construction financing, as well as the remainder of the applied-for financing in the amount of $3.5 million, into long-term debentures on September 17, 2012.

RELATED PARTY TRANSACTIONS

The Corporation's operations include the provision of electricity and services to its sole Shareholder. Electrical energy is sold to the Municipality at the same prices and terms as other electricity customers in their rate class. Street lighting maintenance services are provided at cost. Water and waste water billing, collecting, and customer care services are provided pursuant to an agreement effective April 1, 2008, at rates based on the average cost to provide this service. A summary of the reciprocal charges between the Corporation and the Municipality is provided below.

Summary of Reciprocal Charges between the Corporation and the Municipality

Amounts Billed by the Corporation To the County	**2012**	**2011**
Electrical Energy	$ 3,848,471	$ 3,541,437
Distribution Service Revenue portion actually retained by HCHI	$ 573,544	$ 623,465
Street Lighting - Maintenance	$ 77,715	$ 84,209
Street Lighting - Specific Project Costs	$ 4,805	$ 14,427
Water and Waste Water Billing and Collecting	$ 441,008	$ 428,999
Tree Trimming and Removals	$ 8,887	$ 8,057
Miscellaneous Isolation, Relocation and Service	$ 2,901	$ 1,899
Amounts Billed by the County To the Corporation		
Property Taxes	$ 45,183	$ 45,141
Upgrades to HCHI Infrastructure (Alder St.; Argyle St.)	$ 537,351	$ 26,285
Traffic Signal Upgrades (Hagersville & Dunnville)	$ 176,483	$ -

DIVIDENDS

Dividends on common shares are declared at the discretion of the Board of Directors – subject to applicable law and based on direction from the Shareholder, the Board's proposed dividend policy, and recommendations of Management - with consideration for results of operations, financial condition and future outlook, cash requirements and industry practice.

During 2012 the Corporation declared and paid dividends in the amount of $611,329 (2011 - $716,750) for total dividends paid to date since 2003 in the amount of $4,385,661 to its sole Shareholder, the Municipality of Haldimand County.

Consistent with the Board's proposed dividend policy of paying dividends based on 25% of the previous year's net income – and in the case of 2012, prior to the regulatory adjustment – on May 29, 2013 the Board of Directors of the Corporation declared dividends in the amount of $512,549 to be paid in 2013.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

The accompanying Consolidated Financial Statements of the Corporation, prepared in accordance with Canadian Generally Accepted Accounting Principles, including accounting principles prescribed by the OEB, are the responsibility of Management and have been approved by the Board of Directors (the "Board"). The significant accounting principles, including regulatory treatments, are disclosed in Notes 2 and 3 to the Consolidated Financial Statements.

Fulfilling this responsibility requires the preparation and presentation of consolidated financial statements and other data which necessarily involves the use of estimates and assumptions, which affects the reported amounts of assets and liabilities, based on management's best judgment, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Accounts receivable, unbilled revenue and regulatory assets are reported based on amounts expected to be recovered. Unbilled revenue represents amounts for which the Corporation has a contractual right to receive cash through future billings and is unbilled at period end. Management has exercised careful judgment where estimates were required; however, due to the uncertainty involved in making such estimates, actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the Minister of Energy or the Minister of Finance. Accordingly, these Consolidated Financial Statements reflect all information available to April 3, 2013.

The Consolidated Financial Statements have been examined by Millard, Rouse & Rosebrugh, LLP, Licensed Public Accountants, external auditors of the Corporation. The Independent Auditor's report, which accompanies these statements, outlines the scope of their audit examination and states their opinion.

Management maintains appropriate systems of internal controls designed to provide reasonable assurance that the assets of the Corporation are safeguarded, that transactions are properly authorized and that reliable financial information is relevant, accurate and timely. The internal control systems include formal corporate-wide policies and procedures and an organizational structure that provides a proper delegation of authority and segregation of responsibilities.

The Board, through the Audit and Finance Committee, is responsible for ensuring that Management fulfills its responsibility for financial reporting, accounting systems and internal controls. The Audit and Finance Committee, which is comprised of the same Directors as the Corporation, meet with Management and the external auditors to review the Consolidated Financial Statements and recommends their approval to the Board.

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HALDIMAND COUNTY UTILITIES INC.

CONSOLIDATED FINANCIAL STATEMENTS

For the year ended December 31, 2012

Millard, Rouse & Rosebrugh LLP
Chartered Accountants

HALDIMAND COUNTY UTILITIES INC.

For the year ended December 31, 2012

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Millard, Rouse & Rosebrugh LLP
Chartered Accountants
P.O. Box 57, 91 Main Street South
Hagersville, Ontario N0A 1H0
Telephone: (905) 768-5883
Facsimile: (905) 768-5843

INDEPENDENT AUDITORS' REPORT

To the Shareholder of
Haldimand County Utilities Inc.

We have audited the accompanying consolidated financial statements of Haldimand County Utilities Inc., which comprise the consolidated statement of financial position as at December 31, 2012, and the consolidated statements of retained earnings, income and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements
Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility
Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgement, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Haldimand County Utilities Inc. as at December 31, 2012, and the consolidated results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Millard, Rouse & Rosebrugh LLP

April 3, 2013

CHARTERED ACCOUNTANTS
Licensed Public Accountants

HALDIMAND COUNTY UTILITIES INC.

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

As at December 31	2012	2011
ASSETS		
Current Assets		
Cash and bank	5,733,889	3,991,762
Unbilled revenue	5,589,542	5,422,772
Accounts receivable	4,546,330	3,365,083
OPA conservation program	160	-
Inventory	1,334,139	1,254,484
Income taxes recoverable	589,771	595,251
Prepaid expenses	276,994	270,855
	18,070,825	14,900,207
Property, Plant and Equipment (Note 5)	45,046,411	39,810,509
Regulatory Assets (Note 6)	-	2,284,829
Future Tax Asset	1,614,744	1,269,690
	64,731,980	58,265,235
LIABILITIES		
Current Liabilities		
Accounts payable and accrued expenses	9,212,675	7,760,238
OPA conservation program	-	3,281
Current portion of long term liabilities	1,354,948	1,023,662
	10,567,623	8,787,181
Regulatory Liabilities (Note 6)	2,106,320	-
Long Term Liabilities (Note 7)	13,698,310	11,386,158
	26,372,253	20,173,339
Deferred Credits		
Contributions in aid of construction	4,143,672	3,953,284
Less: Amortization to date	1,007,444	846,180
	3,136,228	3,107,104
SHAREHOLDER'S EQUITY		
Capital (Note 8)	20,289,812	20,289,812
Retained Earnings (Page 3)	14,933,687	14,694,980
	35,223,499	34,984,792
	64,731,980	58,265,235

See accompanying notes

HALDIMAND COUNTY UTILITIES INC.

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

For the year ended December 31	2012	2011
Retained Earnings - Beginning of Year	14,694,980	12,966,414
Net income	850,036	2,445,316
Dividends	(611,329)	(716,750)
Retained Earnings - End of Year	14,933,687	14,694,980

See accompanying notes

HALDIMAND COUNTY UTILITIES INC.

CONSOLIDATED STATEMENT OF INCOME

For the year ended December 31	2012	2011
Service Revenue (Note 9)	54,238,770	53,256,430
Cost of Power	39,895,540	40,380,841
Gross Margin on Service Revenue	14,343,230	12,875,589
Other Operating Revenue (Note 10)	1,363,976	1,425,187
	15,707,206	14,300,776
Expenses		
Distribution, operation and maintenance (Note 11)	4,390,090	4,145,265
Community relations	143,208	45,426
Billing and collecting	1,870,179	1,157,346
General administration	1,946,605	1,987,290
Directors	120,210	71,906
	8,470,292	7,407,233
Amortization	4,100,939	3,132,560
Less: Amortization of contributions in aid of construction	161,264	154,826
	3,939,675	2,977,734
	12,409,967	10,384,967
Income Before Undernoted Items	3,297,239	3,915,809
Interest expense	535,593	485,501
Income Before Income Taxes and Regulatory Adjustment	2,761,646	3,430,308
Income taxes - current (Note 12)	532,237	1,074,407
- future	179,213	(89,415)
	711,450	984,992
Income Before Regulatory Adjustment	2,050,196	2,445,316
Regulatory adjustment - payment in lieu of taxes (Note 13)	1,724,427	-
- future	(524,267)	-
Net regulatory adjustment	1,200,160	-
Net Income	850,036	2,445,316

See accompanying notes

HALDIMAND COUNTY UTILITIES INC.

CONSOLIDATED STATEMENT OF CASH FLOWS

For the year ended December 31	2012	2011
Cash Flows from Operating Activities		
Net Income	850,036	2,445,316
Charges (credits) to income not involving cash		
Amortization	4,103,011	3,136,204
Amortization of contributions in aid of capital	(161,264)	(154,826)
(Gain) loss on disposal of property, plant and equipment	(112,536)	(21,350)
Future income taxes	(345,054)	(89,415)
	4,334,193	5,315,929
Net change in non-cash working capital balances related to operations	20,665	(306,193)
	4,354,858	5,009,736
Cash Flows from Financing Activities		
Dividends	(611,329)	(716,750)
Deposits from customers, retailers and contractors (net)	71,031	(216,703)
Contributions in aid of construction	190,388	166,470
Long term debt	2,572,407	1,977,239
Regulatory liabilities	2,106,320	-
	4,328,817	1,210,256
Cash Flows from Investing Activities		
Purchase of property, plant and equipment	(9,345,962)	(5,096,689)
Proceeds on disposal of property, plant and equipment	119,585	32,343
Regulatory assets	2,284,829	291,902
	(6,941,548)	(4,772,444)
Net Increase in Cash and Cash Equivalents	1,742,127	1,447,548
Opening Cash and Cash Equivalents	3,991,762	2,544,214
Closing Cash and Cash Equivalents	5,733,889	3,991,762

See accompanying notes

1. NATURE OF ACTIVITIES

Haldimand County Utilities Inc. ("the Company") was incorporated under the Ontario Business Corporations Act on October 13, 2000. The company acts as the holding company for the shares of Haldimand County Hydro Inc., Haldimand County Energy Inc., and Haldimand County Generation Inc.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles.

(a) Basis of Consolidation

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries: Haldimand County Hydro Inc., Haldimand County Energy Inc., and Haldimand County Generation Inc.

(b) General

These financial statements have been prepared in accordance with accounting principles for electrical utilities in Ontario as required by the Ontario Energy Board (OEB) under the authority of Section 70(2) of the OEB Act, 1998, of The Energy Competition Act, 1998, and reflect the following policies as set forth in the Ontario Energy Board Accounting Procedures Handbook. All principles employed are in accordance with Canadian generally accepted accounting principles.

(c) Measurement

Financial statements are based on representations that may require estimates to be made in anticipation of future transactions and events and include measurement that may, by their nature, be approximations.

(d) Inventory

Inventory is stated at the lower of cost or net realizable value. Cost is determined on a weighted average basis.

(e) Property, Plant and Equipment and Amortization

Property, plant and equipment are recorded at their historical cost. Amortization is calculated on a straight-line basis over the estimated useful service life as follows:

Buildings	50 years	Distribution stations	30 years
Distribution lines - overhead	25 years	Distribution lines - underground	25 years
Distribution transformers	25 years	Distribution meters	25 years
Rolling stock	8 years	Sentinel lights	10 years
Other capital assets	5 - 50 years		

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(f) Contributions in Aid of Construction

Contributions in aid of construction are reported as deferred credits and amortized over the useful life of the related property, plant and equipment. Contributions prior to 2000 are included in equity as contributed capital.

(g) Revenue Recognition

Distribution revenues are based on OEB approved distribution rates and are recognized as electricity is delivered to customers and collection is reasonably assured. Distribution revenue includes an estimate of revenue based on electricity delivered but not yet invoiced to customers from the last meter reading date to the year end.

(h) Payments in Lieu of Income Taxes (PILs)

Under the Electricity Act, 1998, the Company makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations. Prior to October 1, 2001, the Corporation was not subject to income or capital taxes.

The Company accounts for payments in lieu of corporate taxes using the liability method. Under the liability method, future income taxes reflect the net tax effects of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, as well as for tax losses available to be carried forward to future years that are likely to be realized.

(i) Financial Instruments

Financial instruments are initially recognized at fair value. Subsequent measurement is based on the classification of the financial instrument. The Company has adopted a policy to classify all financial instruments as follows:

(1) - Cash and bank are classified as Held for Trading and measured at fair value.
(2) - Accounts receivable and unbilled revenue are classified as Loans and Receivables and measured at amortized cost using the effective interest rate method.
(3) - Accounts Payable, amounts due to affiliates and long term liabilities are classified as Other Liabilities and measured at amortized cost.
(4) - Purchases and sales of financial instruments are accounted for at the trade date.
(5) - Transaction costs on financial assets and liabilities are expensed as incurred.

The Company has adopted the disclosure and presentation requirements of CICA Handbook Section 3861 rather than Handbook Sections 3862 and 3863.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(j) Regulatory Policies

The Company has adopted the following policies, as prescribed by the Ontario Energy Board (OEB) for rate-regulated enterprises. The policies have resulted in accounting treatments differing from Canadian generally accepted accounting principles for enterprises operating in a non-rate-regulated environment:

1. Various regulatory costs have been deferred in accordance with criteria set out in the OEB's Accounting Procedures handbook. In the absence of such regulation, these costs would have been expensed when incurred under Canadian GAAP.

2. The Company has deferred certain retail settlement variance amounts under the provisions of Article 490 in the OEB's Accounting Procedures handbook.

3. EMERGING ACCOUNTING CHANGES

The Accounting Standards Board (AcSB) confirmed that rate-regulated enterprises will be required to adopt International Financial Reporting Standards (IFRS) by January 1, 2011. The Public Sector Accounting Board released a decision summary confirming that government organizations following commercial practices adhere to standards for publicly accountable entities after January 1, 2011. This was deferred by two years. In March 2013, the AcSB granted an additional optional two year deferral of the adoption of IFRS for rate regulated entities and as such, IFRS may be adopted for financial statements ending December 31, 2015.

The Company has taken the additional deferrals of its adoption of IFRS. Accordingly the Company has prepared its financial statements in accordance with Part V of the CICA Handbook "Pre-Changeover Accounting Standards" for 2012.

The Company continues to assess the impact of conversion to IFRS on its results of operations. The Company will continue to monitor accounting developments with respect to the adoption of IFRS and how any changes will impact on the Company's reporting under IFRS.

4. RATE SETTING

The rates of the Company's electricity distribution business are subject to regulation by the OEB.

With the commencement of the open market, the Company purchases electricity from the Independent Electricity System Operator (IESO), at spot market rates and charges its customers unbundled rates. The unbundled rates include the actual cost of generation and transmission of electricity and an approved rate for electricity distribution. The cost of generation, transmission and other charges such as connection are collected by Haldimand County Hydro Inc. and remitted to the IESO. Debt retirement charges are collected and remitted to the Ontario Electricity Financial Corporation. The Company retains the distribution charge on the customer hydro invoices.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated Company. Such change in timing gives rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. Specific regulatory assets and liabilities are disclosed in Note 6. Haldimand County Hydro Inc.'s approved rate for distribution includes components for the recovery (refund) of regulatory assets (liabilities). The approved rates, effective May 1, 2012, were calculated on a 2010 test year rate base and included a rate of return on equity of 9.85%.

5. PROPERTY, PLANT AND EQUIPMENT

	Cost	Accumulated Amortization	2012	2011
Land	127,140	-	127,140	131,280
Buildings	2,190,518	467,768	1,722,750	1,751,767
Distribution stations	466,496	185,350	281,146	298,441
Distribution lines - overhead	34,184,427	13,500,017	20,684,410	19,143,867
Distribution lines - underground	9,068,449	3,813,842	5,254,607	4,454,474
Distribution transformers	15,070,996	5,568,712	9,502,284	9,194,795
Distribution meters	6,758,882	2,070,790	4,688,092	1,935,650
Sentinel lights	182,449	166,761	15,688	16,829
Rolling stock	2,207,645	1,183,301	1,024,344	1,025,817
Other capital assets	5,274,302	3,528,352	1,745,950	1,857,589
	75,531,304	30,484,893	45,046,411	39,810,509

6. REGULATORY ASSETS (LIABILITIES)

	2012	2011
Deferred payments in lieu of taxes	-	1,011,901
Retail settlement variance accounts	(858,095)	(1,806,073)
Recovery of regulatory asset balances	(1,197,158)	(345,351)
Smart meters	(4,491)	3,508,788
Low voltage services	(52,744)	(113,364)
Hydro One Networks Inc.	6,168	6,081
Special purpose charge	-	22,847
	(2,106,320)	2,284,829

The deferred payments in lieu of taxes represents the accumulated difference in the approved estimate of taxes to be paid and the actual taxes paid.

On April 4, 2012, the OEB announced its decision regarding the Company's rate application. As part of the rate application, the OEB allowed for a recovery (refund) of various regulatory assets (liabilities). These amounts are reported as the Recovery of regulatory asset balances account (RAR). The RAR consists of various OEB approved regulatory asset (liability) account balances as at December 31, 2010.

In 2012, the OEB settled the Deferred payments-in-lieu of taxes regulatory accounts. The OEB adjusted this balance to a liability of $705,925 including interest (see Note 13). The balance owing to customers as at December 31, 2012 is $641,504. This amount is included in the Recovery of regulatory asset balances noted above.

The smart meters regulatory asset account relates to the Province of Ontario's decision to install smart meters throughout Ontario. As at December 31, 2012, the Company has installed its smart meters and received OEB approval for the disposition of and recovery of costs related to smart meters.

The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

7. LONG TERM LIABILITIES	2012	2011
Ontario Infrastructure and Lands Corporation (OILC)		
Interest bearing debentures with semi annual payments of principal and interest:		
(a) Interest at 2.92%, semi-annual payments of $96,499 plus interest, due April 2015	482,496	675,495
(b) Interest at 3.90%, semi-annual payments of $264,418 plus interest, due April 2020	3,966,273	4,495,109
(c) Interest at 4.39%, semi-annual payments of $133,333 plus interest, due April 2025	3,333,333	3,600,000
(d) Interest at 3.77%, semi-annual payments of $120,521 plus interest, due September 2037	6,026,065	-
(e) Interest at 2.91%, semi-annual payments of $35,029 plus interest, due September 2022	700,579	-
Other		
OILC financing advance, interest payable monthly at OILC advance interest rate calculated monthly	-	3,165,735
Customer, retailer and contractor deposits	544,512	473,481
	15,053,258	12,409,820
Current portion	1,354,948	1,023,662
	13,698,310	11,386,158

Based upon current repayment terms, the estimated annual principal repayments and return of customer deposits are as follows:

2013	-	1,354,948
2014	-	1,342,078
2015	-	1,303,767
2016	-	1,165,852
2017	-	1,176,202

The OILC debentures are secured by a general security agreement on all property owned by the Company.

8. CAPITAL	2012	2011
Capital Stock		
Authorized - an unlimited number of common shares		
Issued - 1,001 common shares	19,149,049	19,149,049
Miscellaneous Paid-in Capital	1,140,763	1,140,763
	20,289,812	20,289,812

9. SERVICE REVENUE	2012	2011
Residential	12,420,910	11,240,324
General	8,843,891	10,434,535
Street lighting	18,911	160,904
Sentinel lighting	23,493	24,383
Embedded Distributor	5,258,988	5,398,454
Retailer	6,216,878	4,816,833
Retail transmission and low voltage	5,038,539	5,379,871
Regulatory	2,073,930	2,925,537
Distribution services	14,343,230	12,875,589
	54,238,770	53,256,430

10. OTHER OPERATING REVENUE	2012	2011
Late payment charges	66,213	68,188
Retail service charges	27,137	30,425
Sentinel light rental	78,969	80,880
Interest earned	(13,042)	105,737
Pole rentals	76,396	86,987
Change of occupancy charges	81,660	76,290
Collection charges	253,170	220,830
Reconnection charges	30,240	27,095
Profit on sale of material services	19,646	22,402
Water and sewer billings	441,008	428,999
Gain (loss) on disposal of property, plant and equipment	112,536	21,350
Ontario Power Authority CDM fees	25,101	59,153
Miscellaneous	154,277	144,190
Special purpose charge	-	46,517
MicroFIT monthly service charge	10,665	6,144
	1,363,976	1,425,187

11. DISTRIBUTION, OPERATION AND MAINTENANCE

	2012	2011
Distribution station equipment	67,623	273,608
Overhead distribution lines	2,120,168	2,184,159
Underground distribution lines	342,191	230,768
Distribution transformers	576,537	496,830
Distribution meters	509,933	258,936
Distribution supervision and engineering	756,646	684,298
Sentinel light maintenance	16,992	16,666
	4,390,090	4,145,265

12. INCOME TAXES - CURRENT

The income tax provision was calculated based on taxable income.
Taxable income is calculated as follows:

	2012	2011
Income before income taxes	2,761,646	3,430,308
Less regulatory adjustment	(1,724,427)	-
Amortization in excess of Capital Cost Allowance	704,088	(69,304)
Net change in regulatory assets	4,391,149	291,902
Regulatory assets capitalized for tax purposes	(3,669,190)	258,384
(Gain) Loss on disposal of assets	(112,536)	(21,350)
Other additions and deductions	(207,850)	150,776
Taxable income	2,142,880	4,040,716
Tax at 24.84% (2011 - 26.59%)	532,237	1,074,407

13. OEB DECISION ON CERTAIN REGULATORY ASSETS

The OEB issued its decision and order regarding the disposition of account 1562, Deferred Payments in Lieu of Taxes, on August 30, 2012. The decision set the account balance at a liability of $705,923, including principal and interest. The required adjustment of $1,724,427 has been recorded in the Statement of Income after net income from operations.

14. RELATED PARTY TRANSACTIONS

The Company is wholly owned by The Corporation of Haldimand County. Haldimand County Utilities Inc. owns 100% of Haldimand County Hydro Inc., Haldimand County Energy Inc. and Haldimand County Generation Inc. Transactions between Haldimand County Hydro Inc., Haldimand County Energy Inc., Haldimand County Generation Inc., and Haldimand County Utilities Inc. occur in the normal course of operations and consideration paid is on similar terms as transactions with unrelated parties.

15. PRUDENTIAL SUPPORT

Haldimand County Hydro Inc. is required, through the IESO, to provide security to mitigate the Company's risk of default based on its expected activity in the electricity market. The IESO could draw on this guarantee if Haldimand County Hydro Inc. fails to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2012, the Company provided prudential support in the form of bank letters of credit of $1,796,505. The letters of credit are secured by a general security agreement on all property owned by the Company.

16. CAPITAL MANAGEMENT

The Company's objectives when managing capital are to maintain financial stability such that it can continue to provide returns for the shareholder and benefits for other stakeholders. The Company meets its objectives for managing capital by management oversight and Board monitoring of total capital.

The Company's total capital as at December 31, consists of:

	2012	2011
Total long term liabilities	15,053,258	12,409,820
Less: cash and bank	5,733,889	3,991,762
Net long term liabilities	9,319,369	8,418,058
Total shareholder's equity	35,223,499	34,984,792
Total capital	44,542,868	43,402,850

17. FINANCIAL INSTRUMENTS

Management and the Board monitor and respond as necessary to any risks arising from financial instruments.

Fair Value

The fair value of financial instruments such as cash and bank, accounts receivable, unbilled revenue and accounts payables and accrued liabilities are determined to approximate their recorded value due to their short term maturity.

Interest Rate Risk

The Company's exposure to interest rate risk relates to its outstanding debentures (see Note 7).

Credit Risk

The Company's exposure to credit risk relates to its accounts receivable and unbilled revenue. The Company collects security deposits from customers and retailers in accordance with direction provided by the OEB. The Company held deposits of $504,221 at year end in order to mitigate credit risk.

18. COMPARATIVE FIGURES

Certain of the prior year's figures, provided for purposes of comparison, have been reclassified to conform with the current year's presentation.

19. CONTINGENCIES

A claim has been filed against the Company related to stray voltage. At this time, it is not possible to quantify the effect, if any, of this claim on the financial statements of the Company, consequently no provision for a loss, if any, has been recorded in these financial statements.

Exhibit 1
Appendix F



Legend

- Provincial Highway
- Haldimand Highway
- Haldimand Road
- Former Regional Road Number
- Local Road
- County Boundary

NOTES:

* UPDATED FOR DUPLICATE CIVIC ADDRESS
PROJECT AUGUST 15TH, 2005

HALDIMAND COUNTY, IT'S EMPLOYEES, OFFICERS AND AGENTS ARE NOT RESPONSIBLE FOR ANY ERRORS, OMISSIONS OR INACCURACIES WHETHER DUE TO THEIR OWN NEGLIGENCE OR OTHERWISE.
DO NOT USE FOR OPERATING MAP OR DESIGN PURPOSES.
ALL INFORMATION SHOULD BE VERIFIED.

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NORTH

County of Brant
Six Nations
New Credit
City of Hamilton
Regional Municipality of Niagara
Norfolk County

Caledonia
Sims Lock Road
Blackheath
Willow Grove
York
Empire
Hagersville
Cayuga
Canborough
Canfield
Garnet
Nelles Corners
Decewsville
Balmoral
Townsend
Jarvis
Kohler
Fisherville
Dunnville
Byng
Springvale
Hartford
Cheapside
Selkirk
Rainham Centre
Sweet's Corners
South Cayuga
Nanticoke
Attercliffe Station
Moulton Station
Stromness
Lowbanks
Port Maitland

ONEIDA
SENECA
WALPOLE
N. CAYUGA
CANBOROUGH
S. CAYUGA
RAINHAM
MOULTON
DUNN
SHERBROOKE

Grand River
Lake Erie
Nanticoke Cr.
Sandusk Cr.
Oswego Cr.

Hickory Beach
Selkirk Provincial Park
Peacock Point
Hoover Point
Featherstone Point
Evans Point
Blott Point
Low Point
Grant Point
Rock Point
(Mohawk) Gull Island
Mohawk Point

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Legend

- 27M3, HYDRO ONE, 27600
- 27M4, HH, 27600
- 27M4, HYDRO ONE, 27600
- 27M5, HH, 27600
- 27M6, HH, 27600
- 27M6, HYDRO ONE, 27600
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- 57M4, HH, 27600
- 57M4, HYDRO ONE, 27600
- 57M5, HH, 27600
- 57M5, HYDRO ONE, 27600
- 57M6, HH, 27600
- 57M7, HYDRO ONE, 27600
- 57M8, HYDRO ONE, 27600
- BUS, HYDRO ONE, 27600

105 Hwy 56, Canfield

CANFIELD D.S.

271 Argyle St. North, Caledonia

ARGYLE D.S.

168 3rd Line, Hagersville

LYTHMORE D.S.

1423 Haldimand Rd 55, Jarvis

JARVIS D.S.

2283 River Rd, Cayuga

DECEWSVILLE D.S.

104 Selkirk St, Caledonia

SELKIRK SOUTH D.S.

1105 North Shore Drive, Dunnville

DUNNVILLE D.S.

95 Concession 2, Jarvis

JARVIS T.S.

531 Argyle St. South, Caledonia

CALEDONIA T.S.

1105 North Shore Drive, Dunnville

DUNNVILLE T.S.

City of Hamilton

Six Nations

County of Brant

New Credit

Regional Municipality of Niagara

Norfolk County

Lake Erie

LEGEND

- 8kV SD FOREIGN OWNED O/H PRIMARY
- 8kV 3ph OVERHEAD PRIMARY
- 4.8kV 1ph OVERHEAD PRIMARY
- 16kV 1ph OVERHEAD PRIMARY
- 4.8kV 1ph UNDERGROUND PRIMARY
- 16kV 1ph UNDERGROUND PRIMARY

- SOLID SWITCH
- AIR BREAK SWITCH
- LOAD BREAK SWITCH
- VOLTAGE REGULATOR
- RABBIT
- FUSED SWITCH, 65 AMPS
- RECLOSER
- CUSTOMER OWNED TRANSFORMER
- MID SPAN OPENERS
- PRIMARY METERING UNIT
- NORMALLY OPEN
- CAPACITOR
- SOLAR GENERATION
- WIND GENERATION

Exhibit 1

Appendix G

Haldimand County Hydro Schematic Distribution Map

Haldimand County Hydro

Date: March 31, 2013	Scale: 1:150,000
Drawn by: J.M.G	Rev # 0
	Approved by:

Haldimand County Hydro Inc.
Map of HONI Embedded to HCHI
Exhibit 1
Appendix H

Legend

OVERHEAD_PRIMARY

<all other values>

MAP_LAYER, PHASING, VOLTAGE

- HYDRO ONE, B, 16000
- HH, R, 4800
- HH, W, 4800
- HH, B, 4800
- HH, RWB, 8320
- HH, R, 16000
- HH, W, 16000
- HH, B, 16000
- HH, RWB, 27600
- HYDRO ONE, R, 4800
- HYDRO ONE, W, 4800
- HYDRO ONE, B, 4800
- HYDRO ONE, RWB, 8320
- HYDRO ONE, R, 16000
- HYDRO ONE, W, 16000
- HYDRO ONE, RWB, 27600
- HYDRO ONE, RWB, 230000

From: HYDRO ONE 27M6
ID: 0245200610
Name: GREENS RD PMU
Acct#: 122732

From: HYDRO ONE 27M6
ID: 0200199360
Name: GEORGIA PACIFIC PMU
Acct#: 122738

ARGYLE DS

From: LYTHMORE DS
ID: 0243200980
Name: 6th LINE PMU
Acct#: 122736

CALEDONIA T.S.
DP#: 105518

From: HYDRO ONE 27M3
ID: 0245200620
Name: 5th LINE PMU
Acct#: 122735

From: LYTHMORE DS
ID: 0245200630
Name: 4th LINE PMU
Acct#: 122734

From: HYDRO ONE 27M3
ID: 0200196420
Name: CANADIAN GYPSUM PMU
Acct#: 122739

From: LYTHMORE DS
ID: 0245200640
Name: 3rd LINE PMU
Acct#: 122733

LYTHMORE DS
27.6kV\8kV

JARVIS T.S.
DP#: 105519

From: JARVIS T.S. 57M1
ID: 1000020870
Name: Hydro One - Air Products PMU
Acct#: 122747

City of Hamilton

New Credit

Norfolk County

Lake Erie

Evans Point

Blott Point

Low Point

Featherstone Point

Peacock Point

SELKIRK PARK PMU

LEGEND

27kV 3Ø FOREIGN OWNED O/H PRIMARY
8kV 3Ø FOREIGN OWNED O/H PRIMARY
16kV 1ph OVERHEAD PRIMARY
27kV 3ph OVERHEAD PRIMARY
16kV 1ph UNDERGROUND PRIMARY
4.8kV 1ph OVERHEAD PRIMARY
8kV 3ph OVERHEAD PRIMARY
4.8kV 1ph UNDERGROUND PRIMARY

FAULT INDICATOR
SOLID SWITCH
AIR BREAK SWITCH
LOAD BREAK SWITCH
VOLTAGE REGULATOR
RABBIT
FUSED SWITCH, 65 AMPS
RECLOSER
CUSTOMER OWNED TRANSFORMER
MID SPAN OPENERS
PRIMARY METERING UNIT
NORMALLY OPEN
CAPACITOR
GENERATION POINT
WIND TURBINE

Haldimand County Hydro Inc.
Map of HCHI Embedded to HONI
Exhibit 1
Appendix I

N

Circuit - 27M6
ID: 1000016940

Circuit - 27M3
ID: 1000016910

ID: 1000020220
Name: SPRINGVALE PMU

ID: 1000007570
Name: WAINFLEET PMU

Circuit - 31M2
ID: 1000016880

Circuit - 57M3
ID: 1000009410

Service Area
1252 square kilometers
483 square miles

ID 1000016910	27M3	Caledonia T.S.
ID 1000016920	27M4	
ID 1000016930	27M5	
ID 1000016940	27M6	

Denotes HCH owned feeder
Denotes Hydro One owned feeder

ID 1000016870	31M1	Dunnville T.S.
ID 1000016880	31M2	

Denotes HCH owned feeder
Denotes Hydro One owned feeder

ID 1000009380	57M1	Jarvis T.S.
ID 1000009410	57M3	
ID 1000009390	57M4	
ID 1000009420	57M5	
ID 1000009400	57M6	

Denotes HCH owned feeder
Denotes Hydro One owned feeder

LEGEND

27kV 3Ø FOREIGN OWNED O/H PRIMARY
8kV 3Ø FOREIGN OWNED O/H PRIMARY
16kV 1ph OVERHEAD PRIMARY
27kV 3ph OVERHEAD PRIMARY
16kV 1ph UNDERGROUND PRIMARY
4.8kV 1ph OVERHEAD PRIMARY
8kV 3ph OVERHEAD PRIMARY
4.8kV 1ph UNDERGROUND PRIMARY

FAULT INDICATOR
SOLID SWITCH
AIR BREAK SWITCH
LOAD BREAK SWITCH
VOLTAGE REGULATOR
RABBIT
FUSED SWITCH, 65 AMPS
RECLOSER
CUSTOMER OWNED TRANSFORMER
MID SPAN OPENERS
PRIMARY METERING UNIT
NORMALLY OPEN
CAPACITOR
GENERATION POINT
WIND TURBINE

Haldimand County Distribution			
Haldimand County Hydro	Date: July, 2009	Scale: 1:50,000	
	Drawn by: J.M.G	Approved by:	Rev. No. 6

Lake Erie

2014 Cost of Service Checklist

HALDIMAND COUNTY HYDRO INC.

EB-2013-0134

Filing Requirement Page # Reference

Date: November 15, 2013

		Yes/No/N/A	Evidence Reference, Notes
GENERAL			
Ch 1 p4	Confidential Information - Practice Direction has been followed	N/A	
2	In advance of scheduled application - meet threshold established in Board letter (April 20, 2010)	N/A	
2	Align rate year with fiscal year - rationale for proposed alignment	N/A	
3	Text searchable and bookmarked PDF documents	Yes	Refer to PDF filed November 15, 2013
EXHIBIT 1 - ADMINISTRATIVE DOCUMENTS			
Executive Summary			
7	Overall business strategy including narrative of how the four RRFE outcomes are supported	Yes	Exhibit 1, Tab 1, Schedule 1
7	Revenue Requirement - service RR, increase from previously approved, main drivers	Yes	Exhibit 1, Tab 1, Schedule 2
7	Budgeting Assumptions - economic overview	Yes	Exhibit 1, Tab 1, Schedule 3
7	Load Forecast Summary - load and customer growth, change in kWh and customer numbers, methodology description	Yes	Exhibit 1, Tab 1, Schedule 4
7	Rate Base and Capital Plan - major drivers of DSP, rate base for test year, change from last approved, capex for test year, change from last approved, costs for any REG	Yes	Exhibit 1, Tab 1, Schedule 5
8	OM&A for test year and change from last approved, summary of drivers, inflation assumed, total compensation for test year and change from last approved.	Yes	Exhibit 1, Tab 1, Schedule 6
8	Statement regarding use of Board's cost of capital parameters; summary of any deviations	Yes	Exhibit 1, Tab 1, Schedule 7
8	Cost Allocation & Rate Design - summary of any deviations from Board methodologies and significant changes	Yes	Exhibit 1, Tab 1, Schedule 8
8	Deferral and Variance Account - total disposition (RPP and non-RPP), disposition period, new accounts requested	Yes	Exhibit 1, Tab 1, Schedule 9
8	Bill Impact - total impacts ($ and %)for all classes for typical customers	Yes	Exhibit 1, Tab 1, Schedule 10; Appendix A
Customer Engagement			
8	Overview of customer engagement activities; description of engagement, how customer needs are reflected in application. Explanation if no customer engagement	Yes	Exhibit 1, Tab 2, Schedule 1
Financial Information			
9 & 34	Audited Financial Statements for 2 most recent historical years (i.e. 3 years of historical actuals)	Yes	Exhibit 1, Tab 3, Schedule 1; Appendix B, C, and D
9	Detailed reconciliation of AFS with regulatory financial results filed in the application	Yes	Exhibit 1, Tab 3, Schedule 2
9	Annual Report and MD&A for most recent year of parent company	Yes	Exhibit 1, Tab 3, Schedule 3; Appendix E
9	Rating Agency Reports, if available; Prospectuses, etc. for recent and planned public issuances	N/A	
Materiality Thresholds			
10	Materiality threshold; additional details beyond the threshold if necessary	Yes	Exhibit 1, Tab 4, Schedule 1
Administration			
Ch 1 p2	Certification that evidence is accurate, consistent and complete	Yes	Exhibit 1, Page 2 of 2
10	Table of Contents	Yes	Exhibit 1, Index
10	Statement of who will be affected by application	Yes	Exhibit 1, Tab 5, Schedule 3
10	Publication information (paid, readership, circulation)	Yes	Exhibit 1, Tab 5, Schedule 3
10	Applicant's internet address for viewing of application	Yes	Exhibit 1, Tab 5, Schedule 3
10	Primary contact information (name, address, phone, fax, email)	Yes	Exhibit 1, Tab 5, Schedule 1
10	Identification of legal (or other) representation	Yes	Exhibit 1, Page 1 of 2
10	Requested effective date	Yes	Exhibit 1, Tab 5, Schedule 1
10	Bill impacts - distribution only impacts for 800 kWh residential and 2000 kWh GS<50 (sub-total A of Appendix 2-W)	Yes	Exhibit 1, Tab 1, Schedule 10; Appendix A
11	Form of hearing requested and why	Yes	Exhibit 1, Tab 5, Schedule 1
11	List of approvals requested (and relevant section of legislation), including accounting orders	Yes	Exhibit 1, Tab 5, Schedule 2
11	Change in tax status	N/A	Exhibit 1, Tab 5, Schedule 11
11	Existing accounting orders and departures from USoA including references to the accounting orders	N/A	Exhibit 1, Tab 5, Schedule 13
11	Description of Operating Environment (including map, list of neighbouring utilities)	Yes	Exhibit 1, Tab 5, Schedule 4; Appendix F and G
11	Identification of embedded and/or host distributors	Yes	Exhibit 1, Tab 5, Schedule 6; Appendix H and I
11	Corporate and Utility Organizational Structure, planned changes, corporate entities relationship chart, reporting relationships between LDC and parent	Yes	Exhibit 1, Tab 5, Schedule 7, 8, and 9

2014 Cost of Service Checklist

HALDIMAND COUNTY HYDRO INC.

EB-2013-0134

Filing Requirement Page # Reference

Date: November 15, 2013

		Yes/No/N/A	Evidence Reference, Notes
12 & 13	Corporate Governance: Number of Directors on Board, number of independent directors, how independent judgement is facilitated - Board Mandate; Schedule of Board Meetings - Orientation and Continuing Education for directors - Ethical Business Conduct - written code where available - Process for Nomination of Directors - Committees - function and charter for each committee - Audit Committee - number of independent members, whether members are financially literate	**Yes**	Exhibit 1, Tab 5, Schedule 10
13	Statement regarding any transmission assets previously deemed distribution and whether LDC seeks deeming in current application	**N/A**	Exhibit 1, Tab 5, Schedule 19
5, 6 & 13 Appendices	Accounting Standard used and when it was adopted. - MIFRS - Adoption of IFRS effective Jan 1-15, Jan 1-14 or earlier - CGAAP - must implement regulatory accounting changes for depreciation and capitalization by Jan 1-13 - USGAAP or ASPE - evidence of eligibility, authorization, benefits. Must implement regulatory accounting changes for depreciation and capitalization by Jan 1-13 Summary of changes to accounting policies and quantification of revenue requirement impact. LDC may choose to file Appendix 2-YA (MIFRS) or 2-YB (CGAAP or ASPE).	**Yes**	Exhibit 1, Tab 5, Schedule 15 and 16 and Excel
13	Statement identifying all deviations from Filing Requirements	**Yes**	Exhibit 1, Tab 5, Schedule 14
13	Statement identifying and describing any changes to methodologies used vs previous applications	**N/A**	Exhibit 1, Tab 5, Schedule 16
13	Confirmation that accounting treatment of any non-utility business has segregated activities from rate regulated activities	**Yes**	Exhibit 1, Tab 5, Schedule 18
13	Identification of Board Directives from previous Board Decisions, and how addressed	**Yes**	Exhibit 1, Tab 5, Schedule 18
13	Reference to Conditions of Service - LDC does not need to file Conditions of Service, but must provide reference to website and confirm version is current; identify if there are changes to Conditions of Service as a result of application	**Yes**	Exhibit 1, Tab 5, Schedule 19
EXHIBIT 2 - RATE BASE			
Overview			
14 & 15	Completed Appendix 2-BA1 or 2-BA2 (application material and Excel)	**Yes**	Exhibit 2, Tab 2, Schedule 1 and Excel
14	Opening and Closing balances, average of opening and closing balances for gross assets and accumulated depreciation; working capital allowance (historical actual, bridge and test year forecast)	**Yes**	Exhibit 2, Tab 1, Schedule 1 and Tab 2, Schedule 1
14	Continuity statements (year end balance, including interest during construction and overheads). Year over year variance analysis; explanation where variance greater than materiality Hist. Brd-Approved vs Hist. Actual Hist. Act. Vs previous Hist. Act. Bridge vs. Test	**Yes**	Exhibit 2, Tab 2, Schedule 1 and 3
14 & 15	Opening and closing balances of gross assets and accumulated depreciation must correspond to fixed asset continuity statements. If not, an explanation must be provided (eg. WIP, ARO, smart meter balances). Reconciliation must be between YE 2013 and YE 2014 net book value balances reported on Appendix 2-BA and balances included in rate base calculation	**Yes**	Exhibit 2, Tab 2, Schedule 1, 2, 3, and 4
Gross Assets			
15	Gross Assets Breakdown by Function and by major plant account; description of major plant items for test year	**Yes**	Exhibit 2, Tab 5, Schedule 1, 2, and 3; Appendix A
15	Summary of any ICM adjustment from IRM	**N/A**	Exhibit 2, Tab 7, Schedule 1
15 & 32	Continuity statements must reconcile to calculated depreciation expenses and presented by asset account	**Yes**	Exhibit 2, Tab 2, Schedule 1
Allowance for Working Capital			
15	Working Capital - 13% allowance or Lead/Lag Study or Previous Board Direction	**Yes**	Exhibit 2, Tab 3, Schedule 1
16	Cost of Power must be determined by split between RPP and non-RPP customers based on actual data, use most current RPP price, use current UTR. Should include SME charge.	**Yes**	Exhibit 2, Tab 3, Schedule 1
16	Lead/Lag Study - leads and lags measured in days, dollar-weighted	**N/A**	
Treatment of Stranded Assets Related to Smart Meter Deployment			
17 & 18	Stranded Meters - if not previously addressed by the Board, proposed treatment for recovery that conforms to Board approach: NBV of stranded meters at YE 2013, proposed stranded meter rate riders for applicable customer classes. Explanation for approaches that are not the Board approach Completed Appendix 2-S.	**Yes**	Exhibit 2, Tab 4, Schedule 1 and Excel

2014 Cost of Service Checklist

HALDIMAND COUNTY HYDRO INC.

EB-2013-0134

Filing Requirement Page # Reference

Date: November 15, 2013

		Yes/No/N/A	Evidence Reference, Notes
Capital Expenditures/Distribution System Plan			
19	DSP filed as a stand-alone document	**Yes**	Exhibit 2, Tab 5, Schedule 3; Appendix A
Ch 5 p9	Where applicable, explanation for section headings other than Chapter 5 headings; cross reference table	**N/A**	
Ch 5 p9-10	Distribution System Plan Overview - key elements, sources of cost savings, period covered, vintage of information on investment drivers, changes to asset management process since last DSP filing, dependencies	**Yes**	Section 5.2.1
Ch 5 p10-11	Coordinated Planning with 3rd parties - description of consultations - deliverables of the Regional Planning Process, or status of deliverables - OPA letter in relation to REG investments (Ch 5 p8&9) and Dx response letter	**Yes**	Section 5.2.2; Appendix A, B, C, and D
Ch 5 p11	Performance Measurement - identify and define methods and measures used to monitor DSP performance - summary of performance and trends over historical period. Must include SAIFI, SAIDI and CAIDI for all interruptions and all interruptions excluding loss of supply - explain how information has affected DSP	**Yes**	Section 5.2.3; Appendix E, F, G, and L
Ch5 p12	Asset Management Process Overview - description of AM objectives/corporate goals and how Dx ranks objectives for prioritizing investments	**Yes**	Section 5.3.1
Ch5 p12	Inputs/Outputs of the AM process and information flow for investments; flowchart recommended	**Yes**	Section 5.3.1
Ch 5 p13	Overview of Assets Managed - description of service area (including evolution of features in forecast period affecting DSP), - description of system configuration - service profile and condition by asset type (tables and/or figures) - date data compiled - assessment of degree the capacity of system assets is utilized	**Yes**	Section 5.3.2; Appendix I
Ch 5 p13-14	Asset Lifecycle Optimization - description of asset lifecycle optimization policies and practices, including asset replacement and refurbishment, maintenance planning criteria and assumptions - description of asset life cycle risk management policies and practices, assessment methods and approaches to mitigation	**Yes**	Section 5.3.3; Appendix H
Ch 5 p14-15	Capital Expenditure Plan Summary for significant projects and activities to be undertaken - capability to connect new load or Gx customers, total annual capex over forecast period by investment category, description of how AMP and Capex planning have affected capital expenditures for each category - list, description and total capital cost of material capital expenditures sorted by category (table recommended) - information related to Regional Planning Process (Needs Assessment Report, Regional Planning Status Letter, Regional Infrastructure Plan - as appropriate) - description of customer engagement - Dx expectations of system development over next 5 years - list, description and total capital cost of projects planned in response to customer preferences, to take advantage of technology based opportunities, to study innovative processes (table recommended)	**Yes**	Section 5.4.1
Ch 5 p15	Capital Expenditure Planning Process Overview - description of capex planning objectives/criteria/ assumptions, relationship with AM objectives, policy on consideration of non-distribution alternatives, processes used to identify projects in each investment category, customer feedback and impact on plan, method and criteria used to prioritise REG investments	**Yes**	Section 5.4.2
Ch 5 p16	System Capability Assessment for REG - REG applications > 10 kW, number and MW of REG connections for forecast period, capacity of Dx to connect REG, connection constraints	**Yes**	Section 5.4.3
Ch 5 p16-18 **Ch 2 p19**	Capital Expenditure Summary by Investment Category - completed Table 2 of Ch 5 for historical and forecast period, explanation of markedly different variances plan vs actual, explanation of markedly different variances year over year Table 2 of Ch 5 is provided in Excel format in Appendix 2-AB	**Yes**	Section 5.4.4 and Excel
Ch5 p19	Overall Plan - comparative expenditures by category over historical period, forecast impact of system investment on O&M, drivers of investments by category, information related to Dx system capability assessment	**Yes**	Section 5.4.5
Ch 5 p19-25	Material Investments - For each project that meets materiality threshold set in Ch 2 p10 - general information - total capital, customer attachments, dates, risks, variances, REG investments - evaluation criteria - may include: efficiency, customer value, reliability, etc. - category specific requirements for each project - system access, system renewal, system service, general plant (as applicable)	**Yes**	Section 5.4.5; Appendix J and K

2014 Cost of Service Checklist

HALDIMAND COUNTY HYDRO INC.

EB-2013-0134

Filing Requirement Page # Reference | **Date: November 15, 2013**

		Yes/No/N/A	Evidence Reference, Notes
19	Capital Expenditures - completed Appendix 2-AA showing capex on a project specific basis for 5 historical years, bridge and test; explanation of variances, accounting treatment for projects with life cycle greater than one year	Yes	Exhibit 2, Tab 5, Schedule 2
19	Non-distribution activities - capital expenditures and reconciliation to total capital budget	N/A	
5 & 19-20	Capitalization policy, changes to capitalization since previous rebasing - explanations must be provided. The changes must be identified (eg. capitalization of indirect costs, etc) and the causes of the changes must also be identified.	Yes	Exhibit 2, Tab 5, Schedule 4
20	Capitalization of overhead - Completed Appendix 2-DA (MIFRS) or 2-DB (CGAAP or ASPE) Burden rates must be identified; changes from last rebasing must be identified; LDC must identify burden rates prior to and after the change	Yes	Exhibit 2, Tab 5, Schedule 5
Costs of Eligible Investments			
20	For Eligible Investments - proposal to divide costs per O.Reg. 330/09	Yes	Exhibit 2, Tab 6, Schedule 1 and 2
21	Appendices 2-FA through 2-FC must be filed identifying eligible investments	Yes	Exhibit 2, Tab 6, Schedule 1 and 2 and Excel
Addition of ICM Assets to Rate Base			
21	Distributor with approved ICM - schedule of ICM amounts, variances and explanation	N/A	
21	Balances in 1508 sub-accounts, reconciliation with proposed rate base amounts; recalculated revenue requirement should be compared with rate rider revenue	N/A	
Service Quality and Reliability			
22	5 historical years of ESQRs, explanation for any under-performance and actions taken	Yes	Exhibit 2, Tab 8, Schedule 1
22	5 historical years of SAIDI and SAIFI - for all interruptions and all interruptions excluding loss of supply, explanation for any under-performance and actions taken	Yes	Exhibit 2, Tab 8, Schedule 1
22	Completed Appendix 2-G	Yes	Exhibit 2, Tab 8, Schedule 1 and Excel
EXHIBIT 3 - OPERATING REVENUE			
Load and Revenue Forecasts			
22 & 25	Customer, volume and revenue forecast	Yes	Exhibit 3, Tab 2, Schedule 1 and 2
22	Explanation of causes, assumptions and adjustments for volume forecast. Economic assumptions and data sources for load and customer forecast	Yes	Exhibit 3, Tab 2, Schedule 1 and 2
23 & 24	Regression Model - rationale for choice, regression statistics, explanation for any unintuitive relationships, explanation of modeling approaches and alternative models tested, explanation of weather normalization methodology, sources of data for endogenous and exogenous variables, explanation of any constructed variables; data used in load forecast must be provided in Excel format, including derivation of constructed variables	Yes	Exhibit 3, Tab 2, Schedule 1 and 2; Appendix A and B
24	NAC Model - rationale for choice, data supporting NAC variables, description of accounting for CDM including licence conditions, discussion of weather normalization considerations	N/A	
24 & 25	CDM Adjustment - 2013 and 2014 CDM reductions must take into account 2011 and 2012 CDM program results reported by OPA. CDM adjustment should take into account historical CDM results factored into base load forecast before CDM adjustment	Yes	Exhibit 3, Tab 2, Schedule 1 and 2
25	CDM savings for 2014 LRAMVA balance and adjustment to 2014 load forecast; data by customer class	Yes	Exhibit 3, Tab 2, Schedule 1 and 2
25	Completed Appendix 2-I, or alternative with explanation	Yes	Exhibit 3, Tab 2, Schedule 1 and 2 and Excel
Accuracy of Load Forecast and Variance Analyses			
22 & 25	Schedule of volumes, revenues, customer/connection count by class and total system load: 5 years historical, Board approved, 5 years historical weather normalized, bridge year and test year.	Yes	Exhibit 3, Tab 2, Schedule 1 and 2
25	Customer count increases or decreases for test year - explanation by class; confirmation of year end or average format	Yes	Exhibit 3, Tab 2, Schedule 1 and 2
25	Explanation for any changes in definition or composition of class	N/A	
25	Weather normalized average consumption per customer for historical 5 years, bridge and test	Yes	Exhibit 3, Tab 2, Schedule 1 and 2
25	Explanation of net change in average consumption from last Board approved, and actual historical, bridge and test - for each rate class	Yes	Exhibit 3, Tab 2, Schedule 1 and 2
25	Details of development of billing kW	Yes	Exhibit 3, Tab 2, Schedule 1 and 2
26	Revenues on existing and proposed rates	Yes	Exhibit 3, Tab 1, Schedule 2
26	Variance analysis of volumes, revenues, customer/connection count and total system load: Historical Board approved vs Historical Actual (and Historical Actual weather normalized) Year over year historical weather normalized variance, weather normalized bridge, test year	Yes	Exhibit 3, Tab 2, Schedule 1
24 & 26	Data used to determine forecast should be filed as Excel	Yes	

2014 Cost of Service Checklist

HALDIMAND COUNTY HYDRO INC.

EB-2013-0134

Filing Requirement Page # Reference

Date: November 15, 2013

		Yes/No/N/A	Evidence Reference, Notes
Other Revenue			
26	Breakdown of other distribution revenue accounts; completed Appendix 2-H	Yes	Exhibit 3, Tab 3, Schedule 1 and Excel
26	Variance analysis - year over year, historical, bridge and test	Yes	Exhibit 3, Tab 3, Schedule 2
26	Any new proposed specific service charges	N/A	Exhibit 3, Tab 3, Schedule 2
26 & 30	Revenue from affiliate transactions, shared services, corporate cost allocation	Yes	Exhibit 3, Tab 3, Schedule 2
EXHIBIT 4 - OPERATING COSTS			
Overview			
27	Brief explanation of test year OM&A levels, cost drivers, significant changes, trends, inflation rate assumed, business environment changes	Yes	Exhibit 4, Tab 1, Schedule 1 and 2
Summary and Cost Driver Tables			
28	Summary of recoverable OM&A expenses; Appendix 2-JA	Yes	Exhibit 4, Tab 1, Schedule 2 and Excel
28	OM&A cost drivers; Appendix 2-JB	Yes	Exhibit 4, Tab 1, Schedule 2 and Excel
28	Recoverable OM&A Cost per customer and per FTE; Appendix 2-L	Yes	Exhibit 4, Tab 1, Schedule 2 and Excel
28	Identification of change in OM&A in test year in relation to change in capitalized overhead.	N/A	
28	OM&A variance analysis for test year with respect to bridge and historical years; Appendix 2-DA or 2-DB	Yes	Exhibit 4, Tab 2, Schedule 2 and 3 and Excel
Program Delivery Costs with Variance Analysis			
28	Completed Appendix 2-JC OM&A Programs Table - by program or major functions; include variance analysis between test year and last Board approved and most recent actual	Yes	Exhibit 4, Tab 2, Schedule 2 and 3 and Excel
28	Employee Compensation - complete Appendix 2-K	Yes	Exhibit 4, Tab 2, Schedule 4 and Excel
29	Description of compensation strategy	Yes	Exhibit 4, Tab 2, Schedule 4
29	Explanation for material changes to head count and compensation: year over year variances, inflation, plans for new employees, details on collective agreements, basis for performance pay, filing of any relevant studies	Yes	Exhibit 4, Tab 2, Schedule 4
29	Details of employee benefit programs including pensions for last Board approved, historical, bridge and test; must agree with tax section	Yes	Exhibit 4, Tab 2, Schedule 4
29	Most recent actuary report	N/A	
30	Identification of all shared services among affiliates	Yes	Exhibit 4, Tab 2, Schedule 5
30	Allocation methodology for corporate and shared services, list of costs and allocators, including any third party review	Yes	Exhibit 4, Tab 2, Schedule 5
26 & 30	Completed Appendix 2-N for service provided or received for historical, bridge and test; including reconciliation with revenue included in Other Revenue	Yes	Exhibit 4, Tab 2, Schedule 5 and Excel
30	Identification of any Board of Director costs for affiliates included in LDC costs	Yes	Exhibit 4, Tab 2, Schedule 5
30	Shared Service and Corporate Cost Variance analysis - test year vs last Board approved and most recent actual	Yes	Exhibit 4, Tab 2, Schedule 5
30	Purchased Services - file a copy of procurement policy (signing authority, tendering process, non-affiliate service purchase compliance)	Yes	Exhibit 4, Tab 2, Schedule 6; Appendix A
30 & 31	Explanation for procurements above materiality threshold without competitive tender	Yes	Exhibit 4, Tab 2, Schedule 6
31	Identification of one-time costs in historical, bridge, test; explanation of cost recovery in test (or future years)	Yes	Exhibit 4, Tab 2, Schedule 7
31	Regulatory costs - breakdown of actual and forecast, supporting information related to CoS application, proposed recovery (ie amortized?). Completed Appendix 2-M	Yes	Exhibit 4, Tab 2, Schedule 8
31	LEAP - the greater of 0.12% of forecasted service revenue requirement or $2,000 should be included in OM&A and recovered from all rate classes	Yes	Exhibit 4, Tab 2, Schedule 9
32	Statement whether test year revenue requirement includes legacy programs. If yes, identify programs	N/A	Exhibit 4, Tab 2, Schedule 9
32	Charitable Donations - amounts paid from last Board approved up to test year	N/A	Exhibit 4, Tab 2, Schedule 10
32	Detailed information for any proposal to recover charitable donations (outside of assistance for payment of electricity bills)	N/A	Exhibit 4, Tab 2, Schedule 10
32	Any non-recoverable contributions identified and removed from revenue requirement. Confirm that no political contributions have been included for recovery	N/A	Exhibit 4, Tab 2, Schedule 10
Depreciation, Amortization and Depletion			
15 & 32	Depreciation, Amortization and Depletion details by asset group for historical, bridge and test years. Include asset amount and rate of depreciation/amortization. Must tie back to accumulated depreciation balances in continuity schedule under rate base. Ensure that significant parts of each item of PP&E are depreciated separately	Yes	Exhibit 4, Tab 3, Schedule 2
32	Identify any Asset Retirement Obligations and associated depreciation	Yes	Exhibit 4, Tab 3, Schedule 1
32	Historical depreciation practice and proposal for test year. Variances from the half year rule must be documented with supporting rationale	Yes	Exhibit 4, Tab 3, Schedule 1

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		Yes/No/N/A	Evidence Reference, Notes
33	Copy of depreciation/amortization policy, or equivalent written description; summary of changes to depreciation/amortization policy since last CoS	**Yes**	Exhibit 4, Tab 3, Schedule 1
33	Regulatory Accounting changes for depreciation and capitalization - use of Kinectrics study or another study to justify changes in useful life - list detailing all asset service lives tied to USoA, detail and explain differences in TUL from Kinectrics - Appendix 2-BB - recalculation to determine average remaining service life of opening balance on date of making depreciation changes	**Yes**	Exhibit 4, Tab 3, Schedule 2 and 3 and Excel
33 Appendices	Filing under MIFRS - applicable depreciation appendices (Appendix 2-CA to 2-CM)	**N/A**	
33 Appendices	Filing under CGAAP,ASPE,USGAAP - applicable depreciation appendices (CGAAP or ASPE Appendix 2-CN to 2-CU, USGAAP Appendix 2-CV); details of TUL whether Kinectrics or other, impacts and justification for change	**Yes**	Exhibit 4, Tab 3, Schedule 2 and Excel
PILs and Property Taxes			
33	Completed version of the PILs model (PDF and Excel); derivation of adjustments for historical, bridge, test	**Yes**	Exhibit 4, Tab 4, Schedule 1; Appendix B and Excel
33	Supporting schedules and calculations identifying reconciling items	**Yes**	Exhibit 4, Tab 4, Schedule 1
34	Most recent federal and provincial tax returns	**Yes**	Exhibit 4, Tab 4, Schedule 1; Appendix C
9 & 34	Financial Statements included with tax returns if different from those filed with application	**N/A**	
34	Calculation of Tax Credits	**Yes**	Exhibit 4, Tab 4, Schedule 1
34	Supporting schedules, calculations and explanations for other additions and deductions	**Yes**	Exhibit 4, Tab 4, Schedule 1
34	Exclude from regulatory tax calculation any non-recoverable or disallowed expenses	**Yes**	Exhibit 4, Tab 4, Schedule 1
34 & 35	Completion of Integrity checks listed on p34-35; statement confirming completion	**Yes**	Exhibit 4, Tab 4, Schedule 1
EXHIBIT 5 - COST OF CAPITAL AND CAPITAL STRUCTURE			
36	Statement that LDC adopting Board's guidelines for cost of capital and confirming updates will be done. Alternatively - utility specific cost of capital with supporting evidence	**Yes**	Exhibit 5, Tab 1, Schedule 1
3 & 36 Appendices	Completed Appendix 2-OA for last Board approved and test year; total capitalization (debt and equity) must equate to total rate base	**Yes**	Exhibit 5, Tab 1, Schedule 2 and Excel
36	Completed Appendix 2-OB for historical, bridge and test year	**Yes**	Exhibit 5, Tab 1, Schedule 3 and Excel
37	Explanation for any changes in capital structure	**N/A**	
37	Calculation of cost for each capital component	**Yes**	Exhibit 5, Tab 1, Schedule 2
37	Profit or loss on redemption of debt	**N/A**	
37	Copies of promissory notes or other debt arrangements with affiliates	**N/A**	
37	Explanation of debt rate for each existing debt instrument	**Yes**	Exhibit 5, Tab 1, Schedule 3
37	Forecast of new debt in bridge and test year - details including estimate of rate	**Yes**	Exhibit 5, Tab 1, Schedule 3
37	Not for Profit Corporations - evidence that excess revenue is used to build up operating and capital reserves	**N/A**	
EXHIBIT 6 - REVENUE DEFICIENCY/SUFFICIENCY			
37 & 38	Calculation of Delivery-Related Revenue Deficiency/Sufficiency: net utility income, rate base, actual return on rate base, indicated rate of return, requested rate of return, def/sufficiency, gross def/sufficiency. Def/sufficiency must be net of other costs (eg. electricity price).	**Yes**	Exhibit 6, Tab 1, Schedule 1
38	Summary of drivers for test year def/sufficiency, how much each driver contributes; references in evidence mapped to drivers	**Yes**	Exhibit 6, Tab 1, Schedule 2
38	Impacts of any changes in methodologies to def/sufficiency	**Yes**	Exhibit 6, Tab 1, Schedule 2
38	RRWF - in PDF and Excel. Revenue requirement, def/sufficiency, data entered in RRWF must correspond with other exhibits	**Yes**	Exhibit 6, Tab 1, Schedule 2; Appendix A and Excel
EXHIBIT 7 - COST ALLOCATION			
Cost Allocation Study Requirements			
39	Completed cost allocation study reflecting future loads and costs. Excel version of 2014 cost allocation model (updated load profiles or scaled version of HONI CAIF)	**Yes**	Exhibit 7, Tab 1, Schedule 3 and Excel
39	Description of weighting factors, and rationale for use of default values (if applicable)	**Yes**	Exhibit 7, Tab 1, Schedule 2
39	Hard copy of sheets I-6, I-8, O-1 and O-2 (first page)	**Yes**	Exhibit 7, Tab 1, Schedule 4; Appendix A and B

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		Yes/No/N/A	Evidence Reference, Notes
39 &40	Host Dx - evidence of consultation with embedded Dx - Statement regarding embedded Dx support for approach to allocation of costs - If embedded Dx is separate class - class in cost allocation study and Appendix 2-P - If new embedded Dx class - rationale and supporting evidence (cost of serving, load served, asset ownership information, distribution charges); include in cost allocation study and Appendix 2-P - If embedded Dx billed as GS customer - , include with the GS class in cost allocation model and Appendix 2-P. Provide cost of serving, load served, asset ownership information, distribution charges, appropriateness of rate class. LDC may choose to file Appendix 2-Q.	Yes	Exhibit 7, Tab 1, Schedule 3 and Excel
40	New customer class or eliminated customer class - rationale and restatement of revenue requirement from previous CoS	N/A	
	Class Revenue Requirements and Revenue to Cost Ratios		
41	Completed Appendix 2-P; supporting information for any proposal to re-balance rates	Yes	Exhibit 7, Tab 1, Schedule 4 and Excel
41	Proposal to re-balance to bring R:C ratio into Board policy range; any proposal to re-balance beyond test year.	Yes	Exhibit 7, Tab 1, Schedule 4 and Excel
42	If Cost Allocation Model other than Board model used - exclude LV, exclude DVA such as smart meters	N/A	
EXHIBIT 8 - RATE DESIGN			
42	Monthly fixed charges - 2 decimal places; variable charges - 4 decimal places	Yes	Exhibit 8, Tab 2, Schedule 2; Appendix D
42	Current and Proposed F/V proportion with explanation for any changes	Yes	Exhibit 8, Tab 1, Schedule 2
42 & 43	Table comparing current and proposed fixed charge with floor and ceiling from cost allocation study. Explanation for MFC that exceed the ceiling; analysis must be net of adders and riders	Yes	Exhibit 8, Tab 1, Schedule 2
43	Retail Transmission Service Rate Work Form - PDF and Excel	Yes	Exhibit 8, Tab 1, Schedule 3; Appendix A and B and Excel
16 & 43	RTSR information must be consistent with working capital allowance calculation	Yes	
43	If proposing changes to Retail Service Charge - evidence of consultation and notice	N/A	Exhibit 8, Tab 1, Schedule 3
44	Wholesale Market Service Rate - reflect $0.0056 in application or justify otherwise	Yes	Exhibit 8, Tab 1, Schedule 3
44	Smart Metering Charge - reflect $0.79 in application for Residential and GS<50	Yes	Exhibit 8, Tab 1, Schedule 3
44	Specific Service Charge description/purpose/reason for new and revised SSC; calculations to support charges	N/A	Exhibit 8, Tab 1, Schedule 3
44	Identify any rates and charges in Conditions of Service that do not appear on tariff sheet Explain nature of costs, schedule outlining revenues 2009-2012, bridge and test Whether these charges are included on tariff sheet	N/A	Exhibit 8, Tab 1, Schedule 3
45	Ensure revenue from SSC corresponds with Operating Revenue evidence	Yes	Exhibit 8, Tab 1, Schedule 3
45	Low Voltage Cost (historical, bridge, test), variances and explanations for substantive changes	Yes	Exhibit 8, Tab 1, Schedule 3
45	Support for forecast LV, e.g. Hydro One Sub-Transmission charges	Yes	Exhibit 8, Tab 1, Schedule 3
45	Allocation of LV cost to customer classes (typically proportional to Tx connection revenue)	Yes	Exhibit 8, Tab 1, Schedule 3
45	Proposed LV rates by customer class	Yes	Exhibit 8, Tab 1, Schedule 3
45	Proposed SFLF and Total Loss Factor for test year	Yes	Exhibit 8, Tab 1, Schedule 4
45	Statement as to whether LDC is embedded	Yes	Exhibit 8, Tab 1, Schedule 4
45	Study of losses if required by previous decision	N/A	
45	3-5 years of historical loss factor data - Completed Appendix 2-R	Yes	Exhibit 8, Tab 1, Schedule 4 and Excel
46	Explanation of losses >5%	Yes	Exhibit 8, Tab 1, Schedule 4
46	If proposed loss factor >5%, action plan to reduce losses going forward	Yes	Exhibit 8, Tab 1, Schedule 4
46	Explanation of SFLF if not standard	Yes	Exhibit 8, Tab 1, Schedule 4
46	Current Tariff of Rates and Charges	Yes	Exhibit 8, Tab 2, Schedule 1; Appendix C
46	Track Changes version of current tariff showing proposed changes	Yes	Exhibit 8, Tab 2, Schedule 2; Appendix E
46	Proposed Tariff of Rates - Appendix 2-Z	Yes	Exhibit 8, Tab 2, Schedule 2; Appendix D and Excel
46	Explanation of changes to terms and conditions of service if changes affect application of rates	N/A	
46	Calculations of revenue per class under current and proposed rates; reconciliation of rate class revenue and other revenue to total revenue requirement	Yes	Exhibit 8, Tab 3, Schedule 1
46	Completed Appendix 2-V (Revenue Reconciliation)	Yes	Exhibit 8, Tab 3, Schedule 1 and Excel
46 & 47	Bill Impacts - completed Appendix 2-W for all classes for representative samples of end-users. Must provide residential 800 kWh and GS<50 2,000 kWh. Commodity and regulatory charges held constant	Yes	Exhibit 8, Tab 4, Schedule 1; Appendix F and Excel
47 & 48	Mitigation plan if total bill increase for any customer class is >10% including: specification of class and magnitude of increase, description of mitigation measures, justification, revised impact calculation	N/A	Exhibit 8, Tab 1, Schedule 5
48	Rate Harmonization Plans, if applicable - including impact analysis	Yes	Exhibit 8, Tab 1, Schedule 3

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		Yes/No/N/A	Evidence Reference, Notes
EXHIBIT 9 - DEFERRAL AND VARIANCE ACCOUNTS			
48	List of all outstanding DVA and sub-accounts; provide description of DVAs that were used differently than as described in the APH	**Yes**	Exhibit 9, Tab 2, Schedule 1
48 & 49	Completed DVA continuity schedule for period following last disposition to present - Excel format	**Yes**	Exhibit 9, Tab 2, Schedule 4; Appendix A and B and Excel
49	Interest rates applied to calculate carrying charges (month or quarter)	**Yes**	Exhibit 9, Tab 2, Schedule 2
49 & 55	Explanation if account balances in continuity schedule differs from trial balance in RRR and AFS	**N/A**	Exhibit 9, Tab 2, Schedule 2
49	Identification of Group 2 accounts that will continue/discontinue going forward, with explanation	**N/A**	
49	Proposed allocators for DVA for which Board has not established approved allocator	**N/A**	Exhibit 9, Tab 2, Schedule 4
48 & 49	Statement as to any new accounts, and justification.	**N/A**	
49	Statement whether any adjustments made to DVA balances previously approved by Board on final basis; explanation and amount of adjustment	**N/A**	
49	Breakdown of energy sales and cost of power by USoA - as reported in AFS mapped to USoA. Provide explanation if making a profit or loss on commodity.	**Yes**	Exhibit 9, Tab 1, Schedule 2
49	Statement confirming that IESO GA charge is pro-rated into RPP and non-RPP; provide explanation if not pro-rated.	**Yes**	Exhibit 9, Tab 1, Schedule 2
50	If not addressed previously, disposition of Account 1592 - Completed Appendix 2-TA	**N/A**	
50	If not addressed previously, disposition of Account 1592 sub-account HST/OVAT ITC - analysis that supports conformity with Dec 2010 APH FAQ (particularly #4) - completed Appendix 2-TB Applicant must state the period that the account covers (i.e. Jul 1-2010 up to start of new rate year (year of rebasing))	**Yes**	Exhibit 9, Tab 2, Schedule 2 and Excel
50 & 51	Assuming 2014 CoS filed under MIFRS: One time IFRS transition costs - If IFRS transition costs in rates, file for disposition of balance in IFRS variance account; - completed Appendix 2-U - statement whether any one time IFRS transition costs are embedded in 2014 revenue requirement where it is embedded - explanation for each category of cost recorded in 1508 sub-account - explanation for material variances - statement that no capital costs, ongoing IFRS compliance costs are recorded in 1508 sub-account; provide explanation if this is not the case	**N/A**	
51 & 52	Assuming 2014 CoS filed under MIFRS - 1575 IFRS-CGAAP PP&E account - breakdown of balance, Appendix 2-EA, 2-EB or 2-EC - listing and quantification of drivers - a breakdown for quantification of any accounting changes arising from IFRS in relation to PP&E - volumetric rate rider to clear 1575; explain basis for disposition period - rate of return component is to be applied to 1575 but not recorded in 1575 - statement confirming no carrying charges applied to 1575 - show the balance in DVA continuity schedule	**N/A**	
53 & 54	Assuming 2014 CoS filed under CGAAP or ASPE, or 2014 CoS under MIFRS with changes to depreciation and capitalization in 2012 or 2013 - 1576 IFRS-CGAAP PP&E account - Appendix 2-BA1 or 2-BA2 must not be adjusted for 1576 - breakdown of balance related to 1576, Appendix 2-ED or 2-EE - volumetric rate rider to clear 1576; explain basis for disposition period - rate of return component is to be applied to 1576 but not recorded in 1576 - statement confirming no carrying charges applied to 1576 - show the balance in DVA continuity schedule	**Yes**	Exhibit 9, Tab 4, Schedule 1 and Excel Exhibit 9, Tab 2, Schedule 3
54	Retail Service Charges - material balance in 1518 or 1548 - confirm variances are incremental costs of providing retail services - identify drivers - provide schedule identifying all revenues and expenses listed by USoA for 2012, bridge and test years - state whether Article 490 of APH has been followed; explanation if not followed	**Yes**	Exhibit 9, Tab 2, Schedule 1
54	Retail Service Charges - zero balance in 1518 or 1548 - state whether Article 490 of APH has been followed; explanation if not followed	**N/A**	

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Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
4 & 55	Identify all accounts for which LDC is seeking disposition; identify DVA for which LDC is not proposing disposition and the reasons why Proposal for disposition of deferral accounts for renewable generation connection and smart grid as set out in FR "Distribution System Plans - Filing Under Deemed Conditions of Licence"	Yes	Exhibit 9, Tab 2, Schedule 3 Exhibit 9, Tab 3, Schedule 1 Exhibit 9, Tab 5, Schedule 1
55	Proposed rate riders (Separate rate rider for RSVA GA for non-RPP customers). Default disposition period of 1 year and provide explanation for deviations from default period. Show calculations - allocation of each account, billing determinants and length of disposition period	Yes	Exhibit 9, Tab 2, Schedule 4 Exhibit 9, Tab 3, Schedule 1 Exhibit 9, Tab 5, Schedule 1, 2, 3, and 4; Appendix C and Excel
49 & 55	Statement whether DVA balances before forecasted interest match the last AFS	Yes	Exhibit 9, Tab 2, Schedule 2
55	Provide an explanation of variance > 5% between amounts proposed for disposition and amounts reported in RRR for each account. Provide explanations even if such variances are < 5% threshold if the variances in question relate to: (1) matters of principle (i.e. conformance with the APH or prior Board decisions, and prior period adjustments); and/or, (2) the cumulative effect of immaterial differences over several accounts totaling to a material difference between what is proposed for disposition in total before forecasted interest and what is recorded in the RRR filings	N/A	
55	New DVA - must meet causation, materiality, prudence criteria; include draft accounting order	N/A	
56	LRAMVA - disposition of balance - statement indicating use of most recent input assumptions when calculating lost revenue -statement indicating reliance on most recent CDM evaluation report from OPA; copy of report - Tables for each rate class showing lost revenue by year - lost revenue calculations - energy savings by class and Board approved variable charge - statement that indicates if carrying charges are requested - Third party report for any Board-approved programs	Yes	Exhibit 9, Tab 6, Schedule 1 and 2; Appendix D, E, F, and G
57	Smart Meters - if applying for final disposition, completed smart meter model (excel) must be filed. Refer to G-2011-0001 regarding proposal to dispose of balances. Any previous approval should be documented.	N/A	

TOTAL "NO"	0

Exhibit 2 – Rate Base			
	Tab	**Schedule**	**Appendix**
Overview	1		
Overview of Rate Base		1	
Rate Base Variance Analysis		2	
Gross Assets – Property, Plant, & Equipment	2		
Fixed Asset Continuity Schedules		1	
Gross Asset Table		2	
Variance Analysis on Gross Asset Values		3	
Accumulated Depreciation Table and Variance Analysis		4	
Allowance for Working Capital	3		
Overview and Calculation of Cost of Power		1	
Treatment of Stranded Assets Related to Smart Meter Deployment	4		
Treatment of Stranded Meters		1	
Capital Expenditures	5		
Overview of Capital Expenditures		1	
Capital Expenditures / Projects		2	
Overview of Distribution System Plan		3	
Distribution System Plan; including: • Renewable Energy Generation Plan • Distribution Asset Management Plan o Distribution System Maintenance and Inspection Program o Asset Condition Assessment • Capital Expenditure Plans			A

Exhibit 2 – Rate Base			
	Tab	**Schedule**	**Appendix**
Capitalization Policy		4	
Accounting Changes Under Canadian Generally Accepted Accounting Principles ("CGAAP")		5	
Costs of Eligible Investments for Connection of Qualifying Generation Facilities	6		
Overview of Eligible Investments for Connection of Qualifying Generation Facilities		1	
Calculation for Funding Request – Provincial Recovery and Direct Benefit		2	
Addition of Incremental Capital Module ("ICM") Assets to Rate Base	7		
ICM Capital Asset Amounts		1	
Service Quality and Reliability Performance	8		
Service Quality and Reliability Indicators		1	

RATE BASE

Rate Base Overview

The rate base used for the purpose of calculating the Revenue Requirement used in this Application is the average of the net fixed asset balances at the beginning and the end of the 2014 Test Year, plus a working capital allowance, calculated as 13% of the sum of the cost of power and controllable expenses. The 13% working capital allowance is consistent with the Ontario Energy Board's (the "Board's) letter dated April 12, 2012.

The net fixed assets include those distribution assets that are associated with activities that enable the conveyance of electricity for distribution purposes. Haldimand County Hydro Inc.'s ("HCHI's") rate base calculation excludes any non-distribution assets. Controllable expenses include operating and maintenance, billing and collecting and administrative expenses.

This Exhibit will compare historical data with the 2013 Bridge Year and the 2014 Test Year under Canadian Generally Accepted Accounting Principles ("CGAAP"); as HCHI will not adopt International Financial Reporting Standards ("IFRS") until January 1, 2015 as indicated in Exhibit 1, Tab 5, Schedule 16. However, pursuant to the Board's letter dated July 17, 2012, HCHI has applied the accounting changes to depreciation expense effective January 1, 2013, consistent with the Board's regulatory accounting policy direction in that letter.

HCHI has provided its rate base calculations for the 2010 Board Approved, 2010 Actual, 2011 Actual, 2012 Actual, 2013 Bridge Year and 2014 Test Year in Table 1 below. HCHI's 2014 Test Year rate base is $53,797,605. The year over year gross fixed assets and accumulated depreciation reconcile to the Fixed Asset Continuity statements provided at Tab 2, Schedule 1 of this Exhibit and as filed in the OEB Appendix 2-BA1 "Fixed Asset Continuity CGAAP".

Table 1
Summary of Rate Base

Description	2010 Board Approved	2010 Actual Year	2011 Actual Year	2012 Actual Year	2013 Bridge Year	2014 Test Year
Gross Fixed Assets	58,164,822	57,445,569	62,226,258	71,205,185	75,039,623	81,018,541
Accumulated Depreciation	23,220,128	22,697,861	25,539,681	29,310,689	30,285,402	32,403,359
Net Book Value	34,944,694	34,747,708	36,686,577	41,894,496	44,754,221	48,615,182
Average Net Book Value	34,697,070	34,537,344	35,717,143	39,290,537	43,324,358	46,684,701
Working Capital	36,787,618	44,313,984	47,739,197	48,317,165	53,332,548	54,714,649
Working Capital Allowance	5,518,143	6,647,098	7,160,880	7,247,575	7,999,882	7,112,904
Rate Base	**40,215,213**	**41,184,442**	**42,878,023**	**46,538,112**	**51,324,240**	**53,797,605**

HCHI has provided a summary of its cost of power and controllable expenses used in the calculation for determining working capital for 2010 Board Approved, 2010 Actual, 2011 Actual, 2012 Actual, 2013 Bridge Year and 2014 Test Year in Table 2 below. Details of HCHI's calculation of its working capital allowance are provided at Tab 3, Schedule 1 of this Exhibit.

Table 2
Summary of Working Capital Calculation

Description	2010 Board Approved	2010 Actual Year	2011 Actual Year	2012 Actual Year	2013 Bridge Year	2014 Test Year
Cost of Power	29,342,259	37,439,461	40,380,841	39,895,540	44,619,060	46,008,158
Operations	1,418,231	1,454,866	1,669,077	2,061,484	1,901,712	1,926,274
Maintenance	2,693,492	2,187,634	2,459,521	2,311,614	2,802,176	2,751,043
Billing and Collecting	1,319,423	1,305,988	1,154,952	1,867,865	1,565,594	1,618,934
Community Relations	46,836	42,643	45,426	143,208	64,620	69,320
Administration & General	1,913,930	1,832,252	1,981,685	1,990,255	2,332,985	2,292,810
Property Taxes	53,447	51,140	47,695	47,199	46,401	48,110
Working Capital	**36,787,618**	**44,313,984**	**47,739,197**	**48,317,165**	**53,332,548**	**54,714,649**

The 2014 Test Year rate base has increased by $13,582,392 over the 2010 Board Approved, $7,259,493 over the 2012 Actual, and $2,473,365 over the 2013 Bridge Year. The largest contributor to these increases is in the fixed asset component on account of two factors; (i) the CGAAP accounting change to useful lives; and (ii) the

annual capital expenditure increase since the 2010 Board Approved of $3.5 million to an approximate $5 million in each of the 2011 through 2012 Actuals and the 2013 Bridge Year and 2014 Test Year forecasts. The balance of the 2014 Test Year rate base increase is in the working capital allowance component mainly on account of the increase in the cost of power. These variances are discussed in more detail in Tab 1 Schedule 2 that follows.

HCHI's main objective in managing its distribution assets is to optimize performance of the assets at a reasonable cost with due regard for system reliability, public and employee safety and customer service requirements. This Application incorporates HCHI's 2014 Capital and Operating Budgets in determining the Revenue Requirement to bring these objectives to fruition. Further information will be provided later in this Application. HCHI considers performance-related asset information including, but not limited to, data on reliability, asset age and condition, loading, customer connection requirements, and system configuration, to determine investment needs of the system.

HCHI has been, and continues to be, focused on maintaining the adequacy, reliability, and quality of service to its distribution customers through effective capital spending. The capital spending by account for the each Actual year, the Bridge Year, and the Test Year is provided in Exhibit 2, Tab 2, Schedule 3.

Further information related to HCHI's capital projects and spending is detailed in its Distribution System Plan ("DSP") provided in Appendix A to this Exhibit. Appendices accompanying the DSP include: (i) HCHI's Renewable Energy Generation Plan (the "REG" Plan); (ii) HCHI's Discretionary Capital Projects Prioritization Model; (iii) HCHI's Distribution Asset Management Plan ("DAMP"); (iv) HCHI's Capital Expenditure Plan (2009 to 2013); and (v) HCHI's Capital Expenditure Plan (2014 to 2018). The DAMP includes the Distribution Asset Condition Assessment prepared by Kinectrics Inc. on behalf of HCHI and HCHI's Distribution System Maintenance and Inspection Program which all assist when prioritizing capital project spending and planning for maintenance and inspection of assets.

RATE BASE VARIANCE ANALYSIS

The OEB's *Filing Requirements for Electricity Distribution Rate Applications*, dated July 17, 2013 (the "Filing Requirements") suggest a default materiality threshold for rate base, capital expenditures, Operating, Maintenance and Administrative ("OM&A") costs and other items, and that it be determined based on a distributor's Revenue Requirement. HCHI's distribution Revenue Requirement falls into the category of greater than $10 million and less than or equal to $200 million; resulting in HCHI's materiality threshold calculated as 0.5% of its distribution Revenue Requirement. The calculation for the 2014 Test Year rate base materiality threshold is summarized in Table 3 below.

Table 3
Rate Base Materiality Threshold

	2014 Test Year
Distribution Revenue Requirement	12,874,552
	0.50%
Calculated Materiality Threshold	64,373
Materiality Threshold Used	**64,000**

The following Tables 4 to 8 set out HCHI's rate base and working capital allowance calculations for 2010 Board Approved, 2010 Actual, 2011 Actual, 2012 Actual, 2013 Bridge Year and 2014 Test Year, and the following variances:

- 2010 Actual versus 2010 Board Approved;
- 2011 Actual versus 2010 Actual;
- 2012 Actual versus 2011 Actual
- 2013 Bridge Year versus 2012 Actual; and
- 2014 Test Year versus 2013 Bridge Year.

Below each table HCHI includes details with respect to the variances exceeding the materiality threshold of $64,000 as calculated in Table 3 above. Details of the annual capital expenditures in each year can be found in HCHI's DSP.

2010 Actual versus 2010 Board Approved:

Table 4
Rate Base Variance – 2010 Actual versus 2010 Board Approved

Description	2010 Board Approved	2010 Actual Year	Variance
Gross Fixed Assets	58,164,822	57,445,569	(719,253)
Accumulated Depreciation	23,220,128	22,697,861	(522,267)
Net Book Value	34,944,694	34,747,708	(196,986)
Average Net Book Value	34,697,070	34,537,344	(159,726)
Working Capital	36,787,618	44,313,984	7,526,366
Working Capital Allowance	5,518,143	6,647,098	1,128,955
Rate Base	**40,215,213**	**41,184,442**	**969,229**

In HCHI's 2010 Cost of Service ("COS") rate application, HCHI projected capital expenditures of approximately $3,300,000 when in actual fact HCHI spent $3,256,765. HCHI also incurred disposals in the amount of $342,789 in the 2010 Actual versus the 2010 Board Approved amount of $0. This decrease in actual net capital expenditures is offset by the increase in the working capital allowance. The 2010 Board Approved amount did not include any cost of power expenditures on account of the Embedded Distributor – Hydro One Networks Inc. ("Embedded Distributor - HONI"). The Embedded Distributor – HONI situation commenced in 2009 and was approved as a separate customer rate class in conjunction with HCHI's 2010 COS rate application. It was an oversight by HCHI to not have included cost of power expenditures in its 2010 Board Approved working capital allowance.

2011 Actual versus 2010 Actual:

Table 5
Rate Base Variance – 2011 Actual versus 2010 Actual

Description	2010 Actual Year	2011 Actual Year	Variance
Gross Fixed Assets	57,445,569	62,226,258	4,780,689
Accumulated Depreciation	22,697,861	25,539,681	2,841,820
Net Book Value	34,747,708	36,686,577	1,938,869
Average Net Book Value	34,537,344	35,717,143	1,179,799
Working Capital	44,313,984	47,739,197	3,425,213
Working Capital Allowance	6,647,098	7,160,880	513,782
Rate Base	**41,184,442**	**42,878,023**	**1,693,581**

The rate base increase in 2011 Actual versus the 2010 Actual is a combination of: (i) the increase in HCHI's capital spend in 2011 to an approximate $5 million versus the $3.2 million in 2010; and (ii) the annual increase in the cost of power components of the working capital allowance.

2012 Actual versus 2011 Actual:

Table 6
Rate Base Variance – 2012 Actual versus 2011 Actual

Description	2011 Actual Year	2012 Actual Year	Variance
Gross Fixed Assets	62,226,258	71,205,185	8,978,927
Accumulated Depreciation	25,539,681	29,310,689	3,771,008
Net Book Value	36,686,577	41,894,496	5,207,919
Average Net Book Value	35,717,143	39,290,537	3,573,394
Working Capital	47,739,197	48,317,165	577,968
Working Capital Allowance	7,160,880	7,247,575	86,695
Rate Base	**42,878,023**	**46,538,112**	**3,660,089**

The rate base increase in the 2012 Actual versus the 2011 Actual is on account of the Smart Meter Cost Recovery rate application (EB-2012-0272) approved for disposition November 1, 2012. Smart meter capital and related computer hardware and software, in the total amount of $3,033,357 (net of accumulated depreciation) were added to the 2012 capital expenditures as follows:

- Meter capital - $3,682,120 less accumulated depreciation of $715,893;
- Computer Hardware - $51,094 less accumulated depreciation of $21,785; and
- Computer Software - $62,415 less accumulated depreciation of $24,594.

2013 Bridge Year versus 2012 Actual:

Table 7
Rate Base Variance –2013 Bridge Year versus 2012 Actual

Description	2012 Actual Year	2013 Bridge Year	Variance
Gross Fixed Assets	71,205,185	75,039,623	3,834,438
Accumulated Depreciation	29,310,689	30,285,402	974,713
Net Book Value	41,894,496	44,754,221	2,859,725
Average Net Book Value	39,290,537	43,324,358	4,033,821
Working Capital	48,317,165	53,332,548	5,015,383
Working Capital Allowance	7,247,575	7,999,882	752,307
Rate Base	**46,538,112**	**51,324,240**	**4,786,128**

The rate base in the 2013 Bridge Year is expected to increase over the 2012 Actual by a total of $4,786,128 as detailed in Table 7 above. Part of this increase, $1,459,184, is on account of the CGAAP accounting change in useful lives effective January 1, 2013 as discussed in more detail in Tab 5, Schedule 5 of this Exhibit. The majority of the remaining variance is the $5.5 million capital spend forecast for the 2013 Bridge Year reduced by $483,932 on account of the net book value of stranded meters being requested for disposition with this Application. The stranded meter disposition is discussed in more detail at Tab 4, Schedule 1. The balance of the total rate base

increase is in relation to the increase in working capital allowance on account of the approximate $4 million increase in the cost of power components

2014 Test Year versus 2013 Bridge Year:

Table 8
Rate Base Variance –2014 Test Year versus 2013 Bridge Year

Description	2013 Bridge Year	2014 Bridge Year	Variance
Gross Fixed Assets	75,039,623	81,018,541	5,978,918
Accumulated Depreciation	30,285,402	32,403,359	2,117,957
Net Book Value	44,754,221	48,615,182	3,860,961
Average Net Book Value	43,324,358	46,684,701	3,360,343
Working Capital	53,332,548	54,714,649	1,382,101
Working Capital Allowance	7,999,882	8,207,197	207,315
Rate Base	**51,324,240**	**54,891,898**	**3,567,658**

The main contributor to the rate base increase for the 2014 Test Year is the capital spend of $5.9 million net of $2.1 million accumulated depreciation. The working capital allowance increase of $207,315 is on account of the $1.5 million increase in the cost of power component increases as calculated for rates and load forecast as part of this Application.

GROSS ASSETS – PROPERTY, PLANT, and EQUIPMENT

Fixed Asset Continuity Schedules

HCHI has provided Fixed Asset Continuity Schedules in Tables 10 through 13 for the 2010 Actual, 2011 Actual, 2012 Actual, and 2013 Bridge Year in accordance with CGAAP; that is, prior to the required accounting change for useful lives. Fixed Asset Continuity Schedules have also been provided after this accounting change for the 2013 Bridge Year and 2014 Test Year in Tables 14 and 15, respectively. These same Fixed Asset Continuity Schedules have been filed with this Application in the OEB's Appendix 2-BA1 "Fixed Asset Continuity CGAAP".

All Fixed Asset Continuity Schedules reconcile to the calculated depreciation expenses detailed in Exhibit 4, Tab 3, Schedule 2, and Table 17; that is, except for the 2013 Bridge Year prior to the accounting change for useful lives. However, this particular Fixed Asset Continuity Schedule does reconcile to the calculation for account 1576, "Accounting Changes under CGAAP", in order to account for the change in useful lives and the impact on fixed assets. Refer to OEB Appendix 2-EE "Account 1576 (2013)" and Tab 5, Schedule 6 in this Exhibit.

HCHI confirms that it has not applied for, nor received any, Incremental Capital Module adjustments.

HCHI uses the following accounts and descriptions in the calculations of its net fixed assets:

<u>1609 – Intangible Assets – Capital Contributions Paid</u> – This account includes the cost of one new 27.6 kV feeder breaker position (M3) at the Hydro One Networks Inc. ("Hydro One") owned Dunnville Transformer Station ("TS") to supply HCHI's forecasted increased load. HCHI is responsible for the costs incurred by Hydro One of providing and installing the feeder to connect to Hydro One's breaker position, as well as the revenue metering outside of the TS. The Connection and Cost Recovery Agreement

("CCRA") – Mini was executed on October 7, 2013. The capital additions will occur over a two year period commencing in 2013 through 2014. HCHI has directly assigned 50% of the costs as due to system reliability and included in each year's capital projects accordingly. The remaining 50% of the costs are considered as eligible renewable expansion investment costs and included as part of HCHI's REG Plan (refer to Appendix C of the DSP). This 50% renewable expansion investment portion is further split between (i) a 17% direct benefit component to HCHI's customers and included in the 2013 and 2014 capital projects; and (ii) 83% provincial recovery component recorded to Account 1531 "Renewable Connection Capital Deferral" and requested for provincial recovery as part of this Application. Calculations are provided in Tab 6, Schedule 2 of this Exhibit. The following Table 9 provides a breakdown of the Dunnville TS breaker position capital additions contemplated in 2013 and 2014.

Table 9
Dunnville TS Breaker Position – 2013 and 2014 Capital Additions

	Reliability (50%)	REG Plan (50%)	
Total Capital Addition			
Hydro One Estimated Cost - Total $806,000 - Capital Portion	$ 403,000	$ 403,000	**
REG Plan - Capital Portion - Direct Benefit $403,000 @ 17%	68,510		
Total Capital Addition	**$ 471,510**		
** Requested amount for Provincial Recovery (to be recorded in a deferral account)			
Capital Addition in 2013			
Payment in 2013 - Total $51,000 - Capital Portion	$ 25,500	$ 25,500	
REG Plan - Capital Portion - Direct Benefit $25,500 @ 17%	4,335		
Total 2013 Capital	**$ 29,835**		
Capital Addition in 2014			
Payment in 2014 - Total $755,000 - Capital Portion	$ 377,500	$ 377,500	
REG Plan - Capital Portion - Direct Benefit $377,500 @ 17%	64,175		
Total 2014 Capital	**$ 441,675**		
Total Capital Addition	**$ 471,510**		

1820 – Distribution Station Equipment – Normally Primary below 50 kV – This account is used to record the installed cost of transforming and switching equipment in each of

HCHI's distribution stations, used for the purpose of stepping down to distribution voltages. In HCHI's financial reporting system, costs are separated for each distribution station. The details of each station have been tracked in such a manner that an accurate record of their age, cost, location and voltage characteristics are evident.

1830 – Poles, Towers, and Fixtures – This account is used to record the installed cost of poles, towers, and fixtures used for supporting overhead distribution conductors and service wires. HCHI's distribution system is comprised of mainly wood poles - approximately 98% of the pole population - with some metal and concrete poles in the urban centres.

1835 – Overhead Conductors and Devices – This account is used to record the installed cost of overhead conductors and devices used for distribution purposes. Such items include reclosers (manual and electronic), switches, and conductor.

1840 – Underground Conduit – This account is used to record the installed cost of underground conduit (duct) and tunnels used for housing distribution cables or wires.

1845 – Underground Conductors and Devices – This account is used to record the installed cost of underground conductors and devices used for distribution purposes. HCHI currently categorizes this account into direct buried non-duct cable, in duct cable, and padmount switchgear.

1850 – Line Transformers – This account is used to record the installed cost of overhead and underground distribution line transformers and pole type and underground voltage regulators owned by HCHI for use in transforming electricity to the voltage at which it is to be used by the customer. HCHI further categorizes this account into pole-top transformers, pad mount transformers, and step-down transformers (also known as rabbits). The majority of HCHI's transformers – approximately 90% of the total population - are pole-top. HCHI also stocks a number of transformers in reserve as "Spare Transformer Capital" recorded by type, capacity, and function.

1855 – Services – This account is used to record the installed cost of overhead and underground conductors leading from a point where the wires leave the last pole of the overhead distribution system of the transformers, or manhole, or the top of the pole of the distribution line to the point of connection with the customer's electrical panel. HCHI further categorizes this account into overhead and underground installed costs.

1860 – Meters – This account is used to record the installed cost of meters or devices for use in measuring the electricity delivered to its users. HCHI currently tracks Primary Metering Units, Interval Meters, Smart Meters, and other metering equipment such as a meter cabinet. HCHI's conventional electric meters which became stranded with the deployment of Smart Meters, have been transferred to a sub-account of 1555 , "Smart Meter and Capital Recovery Offset, Sub-account Stranded Meter Costs", as at December 31, 2013, with a request for disposition of this account as part of this Application. Further details are provided in Tab 4, Schedule 1 of this Exhibit. HCHI also stocks a number of meters in reserve as "Spare Meter Capital" recorded by type, capacity, and function.

1905 – Land – This account includes the cost of land used for utility purposes by HCHI and is not included in other land accounts. This category includes the land on which HCHI's head office/service centre is located as well as the land on which its distribution stations are located.

1612 (formerly account 1906) – Land Rights – This account includes the cost of land rights used for utility purposes by HCHI and is not included in other land rights accounts.

1908 – Buildings and Fixtures – This account includes the costs of buildings and fixtures used for utility purposes owned by HCHI at its head office/service centre location in Caledonia, ON.

1915 – Office Furniture and Equipment – This account includes the cost of general office furniture and equipment. HCHI records purchases of low value and/or relatively short life to the appropriate OM&A expense account.

1920 – Computer Equipment - Hardware – This account includes the costs of all computer hardware purchased inclusive of all physical equipment associated with input, processing, storage, and output functions. This consists of various purchases for HCHI related to workstations, servers, laptops, and tablets.

1611 (formerly account 1925) Computer Equipment – Software – This account includes the installed costs of all computer operating and application software purchased or developed in-house. HCHI includes such types of software as its Microsoft Great Plains financial reporting software, Harris NorthStar billing system software, outage management software, website design, and network related software.

1930 – Transportation Equipment – This account contains the costs of all vehicles owned by HCHI, including bucket trucks, pickup trucks, vans, pole trailers, and forklifts. The items in this account are considered unique and identifiable assets.

1940 – Tools, Shop and Garage Equipment – This account includes the cost of tools, loggers, testers, measuring equipment, chain saws, pole dollies, generators, locators, remote control flagmen, and various other equipment used in the general shop.

1955 – Communications Equipment – This account includes amounts relating to telephone and wireless equipment for the general use in connection with utility operations.

1995 – Contributions and Grants – Credit – This account includes amounts relating to contributions from customers (contributed capital) for customer demand projects in accordance with the Distribution System Code (“DSC”) and the provisions of HCHI’s Conditions of Service. HCHI maintains records in this account categorized by the various 1800 series of distribution assets.

Table 10
Fixed Asset Continuity Schedule
As at December 31, 2010

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
47	1820	Distribution Station Equipment <50 kV	$ 580,903	$ -	$ (114,406)	$ 466,497	$ (235,437)	$ (23,512)	$ 108,160	$ (150,789)	$ 315,708
47	1830	Poles, Towers & Fixtures	$ 16,869,155	915,291		$ 17,784,446	$ (6,713,775)	(825,705)		$ (7,539,480)	$ 10,244,966
47	1835	Overhead Conductors & Devices	$ 9,355,782	895,166		$ 10,250,948	$ (2,685,749)	(446,745)		$ (3,132,494)	$ 7,118,454
47	1840	Underground Conduit	$ 700,000	(184,837)		$ 515,163	$ (80,810)	(17,743)		$ (98,553)	$ 416,610
47	1845	Underground Conductors & Devices	$ 6,620,742	509,694		$ 7,130,436	$ (2,706,020)	(318,216)		$ (3,024,236)	$ 4,106,200
47	1850	Line Transformers	$ 10,478,535	483,494		$ 10,962,029	$ (3,340,570)	(441,181)		$ (3,781,751)	$ 7,180,278
47	1855	Services (Overhead & Underground)	$ 2,254,254	124,963		$ 2,379,217	$ (533,527)	(92,686)		$ (626,213)	$ 1,753,004
47	1860	Meters	$ 2,931,270	18,218		$ 2,949,488	$ (962,753)	(114,955)		$ (1,077,708)	$ 1,871,780
N/A	1905	Land	$ 139,071			$ 139,071				$ -	$ 139,071
CEC	1612	Land Rights (Formally known as Account 1906)	$ 695,389			$ 695,389	$ (197,673)	(20,721)		$ (218,394)	$ 476,995
1 b	1908	Buildings & Fixtures	$ 1,997,893	32,033		$ 2,029,926	$ (317,590)	(48,202)		$ (365,792)	$ 1,664,134
8	1915	Office Furniture & Equipment (10 years)	$ 341,917	4,925	(216)	$ 346,626	$ (172,293)	(30,742)	173	$ (202,862)	$ 143,764
50	1920	Computer Equipment - Hardware	$ 515,292	69,180	(45,549)	$ 538,923	$ (396,699)	(52,405)	45,154	$ (403,950)	$ 134,973
50	1611	Computer Software (Formally known as Account 1925)	$ 2,174,830	285,190		$ 2,460,020	$ (1,111,596)	(324,388)	164,220	$ (1,271,764)	$ 1,188,256
10	1930	Transportation Equipment	$ 1,703,282	332,199	(165,107)	$ 1,870,374	$ (938,973)	(165,552)		$ (1,104,525)	$ 765,849
8	1940	Tools, Shop & Garage Equipment	$ 558,803	90,319		$ 649,122	$ (291,656)	(48,478)		$ (340,134)	$ 308,988
8	1955	Communications Equipment	$ 70,790	11,430	(17,511)	$ 64,709	$ (66,281)	(1,800)	17,511	$ (50,570)	$ 14,139
47	1995	Contributions & Grants	$ (3,456,315)	(330,500)		$ (3,786,815)	$ 546,789	144,565		$ 691,354	$ (3,095,461)
	etc.										
		Sub-Total	**$ 54,531,593**	**$ 3,256,765**	**$ (342,789)**	**$ 57,445,569**	**$ (20,204,613)**	**$ (2,828,466)**	**$ 335,218**	**$ (22,697,861)**	**$ 34,747,708**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	**$ -**
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	**$ -**
		Total PP&E	**$ 54,531,593**	**$ 3,256,765**	**$ (342,789)**	**$ 57,445,569**	**$ (20,204,613)**	**$ (2,828,466)**	**$ 335,218**	**$ (22,697,861)**	**$ 34,747,708**

Table 11
Fixed Asset Continuity Schedule
As at December 31, 2011

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
47	1820	Distribution Station Equipment <50 kV	$ 466,497	$ -		$ 466,497	$ (150,789)	$ (17,266)		$ (168,055)	$ 298,442
47	1830	Poles, Towers & Fixtures	$ 17,784,446	1,624,237		$ 19,408,683	$ (7,539,480)	(863,874)		$ (8,403,354)	$ 11,005,329
47	1835	Overhead Conductors & Devices	$ 10,250,948	1,506,540		$ 11,757,488	$ (3,132,494)	(486,457)		$ (3,618,951)	$ 8,138,537
47	1840	Underground Conduit	$ 515,163	118,618		$ 633,781	$ (98,553)	(20,443)		$ (118,996)	$ 514,785
47	1845	Underground Conductors & Devices	$ 7,130,436	161,753		$ 7,292,189	$ (3,024,236)	(328,265)		$ (3,352,501)	$ 3,939,688
47	1850	Line Transformers	$ 10,962,029	652,039		$ 11,614,068	$ (3,781,751)	(464,341)		$ (4,246,092)	$ 7,367,976
47	1855	Services (Overhead & Underground)	$ 2,379,217	172,584		$ 2,551,801	$ (626,213)	(98,767)		$ (724,980)	$ 1,826,821
47	1860	Meters	$ 2,949,488	182,218		$ 3,131,706	$ (1,077,708)	(118,348)		$ (1,196,056)	$ 1,935,650
N/A	1905	Land	$ 139,071		$ (7,792)	$ 131,279				$ -	$ 131,279
CEC	1612	Land Rights (Formally known as Account 1906)	$ 695,389			$ 695,389	$ (218,394)	(20,721)		$ (239,115)	$ 456,274
1 b	1908	Buildings & Fixtures	$ 2,029,926	138,090		$ 2,168,016	$ (365,792)	(50,456)		$ (416,248)	$ 1,751,768
8	1915	Office Furniture & Equipment (10 years)	$ 346,626	17,332	(816)	$ 363,142	$ (202,862)	(30,691)	333	$ (233,220)	$ 129,922
50	1920	Computer Equipment - Hardware	$ 538,923	75,941	(97,327)	$ 517,537	$ (403,950)	(57,281)	94,733	$ (366,498)	$ 151,039
50	1611	Computer Software (Formally known as Account 1925)	$ 2,460,020	124,463		$ 2,584,483	$ (1,435,984)	(354,793)		$ (1,790,777)	$ 793,706
10	1930	Transportation Equipment	$ 1,870,374	258,266	(41,070)	$ 2,087,570	$ (940,305)	(162,393)	40,947	$ (1,061,751)	$ 1,025,819
8	1940	Tools, Shop & Garage Equipment	$ 649,122	58,717		$ 707,839	$ (340,134)	(55,052)		$ (395,186)	$ 312,653
8	1955	Communications Equipment	$ 64,709	3,365		$ 68,074	$ (50,570)	(3,511)		$ (54,081)	$ 13,993
47	1995	Contributions & Grants	$ (3,786,815)	(166,469)		$ (3,953,284)	$ 691,354	154,826		$ 846,180	$ (3,107,104)
	etc.										
		Sub-Total	**$ 57,445,569**	**$ 4,927,694**	**$ (147,005)**	**$ 62,226,258**	**$ (22,697,861)**	**$ (2,977,833)**	**$ 136,013**	**$ (25,539,681)**	**$ 36,686,577**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	**$ -**
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	**$ -**
		Total PP&E	**$ 57,445,569**	**$ 4,927,694**	**$ (147,005)**	**$ 62,226,258**	**$ (22,697,861)**	**$ (2,977,833)**	**$ 136,013**	**$ (25,539,681)**	**$ 36,686,577**

Less: CDM-OPA Allocated Costs - *Depreciation Expense*

Building	$ 925
Office Equipment	$ 563
Computer Hardware	$ 1,050
Computer Software	$ 1,106
Net Depreciation Expense	**$ (2,974,189)**

Table 12
Fixed Asset Continuity Schedule
As at December 31, 2012

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
47	1820	Distribution Station Equipment <50 kV	$ 466,497			$ 466,497	$ (168,055)	$ (17,295)		$ (185,350)	$ 281,147
47	1830	Poles, Towers & Fixtures	$ 19,408,683	1,218,769		$ 20,627,452	$ (8,403,354)	(922,254)		$ (9,325,608)	$ 11,301,844
47	1835	Overhead Conductors & Devices	$ 11,757,488	1,799,487		$ 13,556,975	$ (3,618,951)	(555,459)		$ (4,174,410)	$ 9,382,565
47	1840	Underground Conduit	$ 633,781	732,415		$ 1,366,196	$ (118,996)	(28,384)		$ (147,380)	$ 1,218,816
47	1845	Underground Conductors & Devices	$ 7,292,189	410,064		$ 7,702,253	$ (3,352,501)	(313,961)		$ (3,666,462)	$ 4,035,791
47	1850	Line Transformers	$ 11,614,068	773,837		$ 12,387,905	$ (4,246,092)	(492,175)		$ (4,738,267)	$ 7,649,638
47	1855	Services (Overhead & Underground)	$ 2,551,801	131,291		$ 2,683,092	$ (724,980)	(105,464)		$ (830,444)	$ 1,852,648
47	1860	Meters	$ 3,131,706	(95,933)	$ (1,651)	$ 3,034,122	$ (1,196,056)	(117,787)	$ 714	$ (1,313,129)	$ 1,720,993
47	1860	Smart Meters	$ -	3,724,761		$ 3,724,761	$ -	(757,661)		$ (757,661)	$ 2,967,100
N/A	1905	Land	$ 131,279		(4,140)	$ 127,139				$ -	$ 127,139
CEC	1612	Land Rights (Formally known as Account 1906)	$ 695,389			$ 695,389	$ (239,115)	(20,777)		$ (259,892)	$ 435,497
1 b	1908	Buildings & Fixtures	$ 2,168,016	22,502		$ 2,190,518	$ (416,248)	(51,520)		$ (467,768)	$ 1,722,750
8	1915	Office Furniture & Equipment (10 years)	$ 363,142	4,711	(2,217)	$ 365,636	$ (233,220)	(29,830)	1,810	$ (261,240)	$ 104,396
50	1920	Computer Equipment - Hardware	$ 517,537	118,989	(51,431)	$ 585,095	$ (366,498)	(79,968)	50,469	$ (395,997)	$ 189,098
50	1611	Computer Software (Formally known as Account 1925)	$ 2,584,483	231,088	(50,502)	$ 2,765,069	$ (1,790,777)	(360,638)	49,911	$ (2,101,504)	$ 663,565
10	1930	Transportation Equipment	$ 2,087,570	186,784	(66,708)	$ 2,207,646	$ (1,061,751)	(188,244)	66,695	$ (1,183,300)	$ 1,024,346
8	1940	Tools, Shop & Garage Equipment	$ 707,839	87,199		$ 795,038	$ (395,186)	(56,592)		$ (451,778)	$ 343,260
8	1955	Communications Equipment	$ 68,074			$ 68,074	$ (54,081)	(3,861)		$ (57,942)	$ 10,132
47	1995	Contributions & Grants	$ (3,953,284)	(190,388)		$ (4,143,672)	$ 846,180	161,263		$ 1,007,443	$ (3,136,229)
	etc.										
		Sub-Total	**$ 62,226,258**	**$ 9,155,576**	**$ (176,649)**	**$ 71,205,185**	**$ (25,539,681)**	**$ (3,940,607)**	**$ 169,599**	**$ (29,310,689)**	**$ 41,894,496**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	**$ -**
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	**$ -**
		Total PP&E	**$ 62,226,258**	**$ 9,155,576**	**$ (176,649)**	**$ 71,205,185**	**$ (25,539,681)**	**$ (3,940,607)**	**$ 169,599**	**$ (29,310,689)**	**$ 41,894,496**

Less: CDM-OPA Allocated Costs - *Depreciation Expense*

Building	$ 927
Office Equipment	$ 537
Computer Hardware	$ 1,435
Computer Software	$ 1,431
Net Depreciation Expense	**$ (3,936,277)**

Table 13
Fixed Asset Continuity Schedule
As at December 31, 2013
(Prior Accounting Change to Useful Lives)

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
CEC	1609	Distribution Station Equipment <50 kV - Capital Contribution Paid	$ -	$ 29,835		$ 29,835	$ -	$ (497)		$ (497)	$ 29,338
47	1820	Distribution Station Equipment <50 kV	$ 466,497			$ 466,497	$ (185,350)	(17,266)		$ (202,616)	$ 263,881
47	1830	Poles, Towers & Fixtures	$ 20,627,452	1,907,831		$ 22,535,283	$ (9,325,608)	(995,416)		$ (10,321,024)	$ 12,214,259
47	1835	Overhead Conductors & Devices	$ 13,556,975	1,249,008		$ 14,805,983	$ (4,174,410)	(612,066)		$ (4,786,476)	$ 10,019,507
47	1840	Underground Conduit	$ 1,366,196	456,855		$ 1,823,051	$ (147,380)	(65,486)		$ (212,866)	$ 1,610,185
47	1845	Underground Conductors & Devices	$ 7,702,253	749,544		$ 8,451,797	$ (3,666,462)	(336,723)		$ (4,003,185)	$ 4,448,612
47	1850	Line Transformers	$ 12,387,905	859,557		$ 13,247,462	$ (4,738,267)	(520,610)		$ (5,258,877)	$ 7,988,585
47	1855	Services (Overhead & Underground)	$ 2,683,092	240,643		$ 2,923,735	$ (830,444)	(112,750)		$ (943,194)	$ 1,980,541
47	1860	Meters	$ 3,034,121	30,060	$ (1,666,572)	$ 1,397,609	$ (1,313,129)	(122,797)	$ 1,182,640	$ (253,286)	$ 1,144,323
47	1860	Smart Meters	$ 3,724,762	118,390		$ 3,843,152	$ (757,661)	(247,073)		$ (1,004,734)	$ 2,838,418
N/A	1905	Land	$ 127,139			$ 127,139				$ -	$ 127,139
CEC	1612	Land Rights (Formally known as Account 1906)	$ 695,389			$ 695,389	$ (259,892)	(20,720)		$ (280,612)	$ 414,777
1 b	1908	Buildings & Fixtures	$ 2,190,518			$ 2,190,518	$ (467,768)	(51,715)		$ (519,483)	$ 1,671,035
8	1915	Office Furniture & Equipment (10 years)	$ 365,636	5,000		$ 370,636	$ (261,240)	(23,021)		$ (284,261)	$ 86,375
50	1920	Computer Equipment - Hardware	$ 585,095	57,125		$ 642,220	$ (395,997)	(67,921)		$ (463,918)	$ 178,302
50	1611	Computer Software (Formally known as Account 1925)	$ 2,765,069	196,000		$ 2,961,069	$ (2,101,504)	(324,494)		$ (2,425,998)	$ 535,071
10	1930	Transportation Equipment	$ 2,207,646	247,281		$ 2,454,927	$ (1,183,300)	(206,206)		$ (1,389,506)	$ 1,065,421
8	1940	Tools, Shop & Garage Equipment	$ 795,038	35,685		$ 830,723	$ (451,778)	(59,581)		$ (511,359)	$ 319,364
8	1955	Communications Equipment	$ 68,074			$ 68,074	$ (57,942)	(3,860)		$ (61,802)	$ 6,272
47	1995	Contributions & Grants	$ (4,143,672)	(681,804)		$ (4,825,476)	$ 1,007,443	171,665		$ 1,179,108	$ (3,646,368)
	etc.										
		Sub-Total	**$ 71,205,185**	**$ 5,501,010**	**$ (1,666,572)**	**$ 75,039,623**	**$ (29,310,689)**	**$ (3,616,537)**	**$ 1,182,640**	**$ (31,744,586)**	**$ 43,295,037**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	**$ -**
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	**$ -**
		Total PP&E	**$ 71,205,185**	**$ 5,501,010**	**$ (1,666,572)**	**$ 75,039,623**	**$ (29,310,689)**	**$ (3,616,537)**	**$ 1,182,640**	**$ (31,744,586)**	**$ 43,295,037**

Less: CDM-OPA Allocated Costs - *Depreciation Expense*

Building	$ 946
Office Equipment	$ 421
Computer Hardware	$ 1,243
Computer Software	$ 1,207
Net Depreciation Expense	**$ (3,612,720)**

Table 14
Fixed Asset Continuity Schedule
As at December 31, 2013
(Post Accounting Change to Useful Lives)

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
CEC	1609	Distribution Station Equipment <50 kV - Capital Contribution Paid	$ -	29,835		$ 29,835	$ -	$ (332)		$ (332)	$ 29,503
47	1820	Distribution Station Equipment <50 kV	$ 466,497			$ 466,497	$ (185,350)	(8,035)		$ (193,385)	$ 273,112
47	1830	Poles, Towers & Fixtures - Wood Poles	$ 20,543,025	1,907,831		$ 22,450,856	$ (9,281,040)	(287,600)		$ (9,568,640)	$ 12,882,216
47	1830	Poles, Towers & Fixtures - Metal/Concrete Poles	$ 84,427			$ 84,427	$ (44,568)	(835)		$ (45,403)	$ 39,024
47	1835	Overhead Conductors & Devices - Conductor	$ 12,599,263	1,249,008		$ 13,848,271	$ (3,718,103)	(210,754)		$ (3,928,857)	$ 9,919,414
47	1835	Overhead Conductors & Devices - Switches	$ 510,902			$ 510,902	$ (273,141)	(7,260)		$ (280,401)	$ 230,501
47	1835	Overhead Conductors & Devices - Reclosures	$ 446,811			$ 446,811	$ (183,166)	(8,446)		$ (191,612)	$ 255,199
47	1840	Underground Conduit - Duct	$ 1,366,196	456,855		$ 1,823,051	$ (147,380)	(30,125)		$ (177,505)	$ 1,645,546
47	1845	Underground Conductors & Devices - Cable (Non-Duct)	$ 6,219,026	33,369		$ 6,252,395	$ (2,961,123)	(173,968)		$ (3,135,091)	$ 3,117,304
47	1845	Underground Conductors & Devices - Cable (In Duct)	$ 1,428,183	639,620		$ 2,067,803	$ (682,394)	(33,438)		$ (715,832)	$ 1,351,971
47	1845	Underground Conductors & Devices - Switchgear	$ 55,043	76,555		$ 131,598	$ (22,945)	(2,915)		$ (25,860)	$ 105,738
47	1850	Line Transformers - Pole Top	$ 9,439,683	581,783		$ 10,021,466	$ (3,943,726)	(188,586)		$ (4,132,312)	$ 5,889,154
47	1850	Line Transformers - Padmount	$ 2,420,047	216,524		$ 2,636,571	$ (703,172)	(53,924)		$ (757,096)	$ 1,879,475
47	1850	Line Transformers - Step-Down (Rabbits)	$ 314,345	61,250		$ 375,595	$ (91,369)	(7,418)		$ (98,787)	$ 276,808
47	1850	Line Transformers - Spare Capital	$ 213,830			$ 213,830	$ -			$ -	$ 213,830
47	1855	Services - Overhead	$ 984,278	110,516		$ 1,094,794	$ (294,207)	(13,931)		$ (308,138)	$ 786,656
47	1855	Services - Underground	$ 1,698,814	130,127		$ 1,828,941	$ (536,237)	(44,340)		$ (580,577)	$ 1,248,364
47	1860	Meters - Primary Metering Units	$ 129,969	9,480		$ 139,449	$ (22,207)	(6,836)		$ (29,043)	$ 110,406
47	1860	Meters - Interval Meters & Other Metering Equipment	$ 1,142,904	20,580		$ 1,163,484	$ (150,783)	(218,149)		$ (368,932)	$ 794,552
47	1860	Meters - Smart Meters	$ 3,724,762	118,390		$ 3,843,152	$ (757,661)	(247,073)		$ (1,004,734)	$ 2,838,418
47	1860	Meters - Stranded Conventional Meters	$ 1,666,572		$ (1,666,572)	$ -	$ (1,140,139)	(42,501)	$ 1,182,640	$ -	$ -
47	1860	Meters - Spare Capital	$ 94,676			$ 94,676	$ -			$ -	$ 94,676
N/A	1905	Land	$ 127,139			$ 127,139				$ -	$ 127,139
CEC	1612	Land Rights (Formally known as Account 1906)	$ 695,389			$ 695,389	$ (259,892)	(20,720)		$ (280,612)	$ 414,777
1 b	1908	Buildings & Fixtures	$ 2,190,518			$ 2,190,518	$ (467,768)	(51,715)		$ (519,483)	$ 1,671,035
8	1915	Office Furniture & Equipment (10 years)	$ 365,636	5,000		$ 370,636	$ (261,240)	(23,021)		$ (284,261)	$ 86,375
50	1920	Computer Equipment - Hardware	$ 585,095	57,125		$ 642,220	$ (395,997)	(67,921)		$ (463,918)	$ 178,302
50	1611	Computer Software (Formally known as Account 1925)	$ 2,765,069	196,000		$ 2,961,069	$ (2,101,504)	(324,494)		$ (2,425,998)	$ 535,071
10	1930	Transportation Equipment - Bucket Trucks	$ 1,759,603	207,000		$ 1,966,603	$ (904,828)	(97,234)		$ (1,002,062)	$ 964,541
10	1930	Transportation Equipment - Pickups and Vans	$ 364,206	40,281		$ 404,487	$ (227,321)	(39,005)		$ (266,326)	$ 138,161
10	1930	Transportation Equipment - Trailers	$ 83,837			$ 83,837	$ (51,151)	(2,000)		$ (53,151)	$ 30,686
8	1940	Tools, Shop & Garage Equipment	$ 795,038	35,685		$ 830,723	$ (451,778)	(59,581)		$ (511,359)	$ 319,364
8	1955	Communications Equipment	$ 68,074			$ 68,074	$ (57,942)	(3,860)		$ (61,802)	$ 6,272
47	1995	Contributions & Grants - Wood Poles	$ (739,792)	(88,153)		$ (827,945)	$ 184,802	13,528		$ 198,330	$ (629,615)
47	1995	Contributions & Grants - Metal / Concrete Poles	$ -			$ -	$ -	0		$ -	$ -
47	1995	Contributions & Grants - O/H Conductor	$ (206,948)	(5,254)		$ (212,202)	$ 39,943	3,758		$ 43,701	$ (168,501)
47	1995	Contributions & Grants - O/H Line Switches	$ (8,391)			$ (8,391)	$ 1,722	167		$ 1,889	$ (6,502)
47	1995	Contributions & Grants - O/H Reclosures	$ (7,345)			$ (7,345)	$ 1,507	167		$ 1,674	$ (5,671)
47	1995	Contributions & Grants - U/G Conduit	$ (303,943)	(116,303)		$ (420,246)	$ 66,336	6,494		$ 72,830	$ (347,416)
47	1995	Contributions & Grants - U/G Conductor (Non-Duct)	$ (1,081,893)			$ (1,081,893)	$ 263,019	34,702		$ 297,721	$ (784,172)
47	1995	Contributions & Grants - U/G Conductor (In Duct)	$ (242,982)	(310,010)		$ (552,992)	$ 59,071	9,333		$ 68,404	$ (484,588)
47	1995	Contributions & Grants - Pole Top Transformers	$ (668,018)	(31,658)		$ (699,676)	$ 179,942	15,109		$ 195,051	$ (504,625)
47	1995	Contributions & Grants - Padmount Transformers	$ (171,269)	(78,787)		$ (250,056)	$ 46,091	4,758		$ 50,849	$ (199,207)
47	1995	Contributions & Grants - Step-Down Transformers	$ (22,227)			$ (22,227)	$ 5,982	490		$ 6,472	$ (15,755)
47	1995	Contributions & Grants - O/H Services	$ (149,478)	(20,126)		$ (169,604)	$ 40,101	2,223		$ 42,324	$ (127,280)
47	1995	Contributions & Grants - U/G Services	$ (258,042)	(23,692)		$ (281,734)	$ 69,225	7,056		$ 76,281	$ (205,453)
47	1995	Contributions & Grants - Primary Metering Units	$ (156,852)			$ (156,852)	$ 21,959	8,431		$ 30,390	$ (126,462)
47	1995	Contributions & Grants - Intervals & Other Metering Equipment	$ (28,461)	(1,158)		$ (29,619)	$ 6,242	2,781		$ 9,023	$ (20,596)
47	1995	Contributions & Grants - Smart Meters	$ (98,031)	(6,663)		$ (104,694)	$ 21,501	9,667		$ 31,168	$ (73,526)
	etc.										
		Sub-Total	**$ 71,205,185**	**$ 5,501,010**	**$ (1,666,572)**	**$ 75,039,623**	**$ (29,310,689)**	**$ (2,157,353)**	**$ 1,182,640**	**$ (30,285,402)**	**$ 44,754,221**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	**$ -**
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	**$ -**
		Total PP&E	**$ 71,205,185**	**$ 5,501,010**	**$ (1,666,572)**	**$ 75,039,623**	**$ (29,310,689)**	**$ (2,157,353)**	**$ 1,182,640**	**$ (30,285,402)**	**$ 44,754,221**

Less: CDM-OPA Allocated Costs - *Depreciation Expense*

Building	$ 946
Office Equipment	$ 421
Computer Hardware	$ 1,243
Computer Software	$ 1,207
Net Depreciation Expense	**$ (2,153,536)**

Table 15
Fixed Asset Continuity Schedule
As at December 31, 2014

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
CEC	1609	Distribution Station Equipment <50 kV - Capital Contribution Paid	$ 29,835	441,675		$ 471,510	$ (332)	$ (5,571)		$ (5,903)	$ 465,607
47	1820	Distribution Station Equipment <50 kV	$ 466,497	5,000		$ 471,497	$ (193,385)	(8,091)		$ (201,476)	$ 270,021
47	1830	Poles, Towers & Fixtures - Wood Poles	$ 22,450,856	1,615,483		$ 24,066,339	$ (9,568,640)	(322,835)		$ (9,891,475)	$ 14,174,864
47	1830	Poles, Towers & Fixtures - Metal/Concrete Poles	$ 84,427			$ 84,427	$ (45,403)	(835)		$ (46,238)	$ 38,189
47	1835	Overhead Conductors & Devices - Conductor	$ 13,848,271	1,117,956		$ 14,966,227	$ (3,928,857)	(234,423)		$ (4,163,280)	$ 10,802,947
47	1835	Overhead Conductors & Devices - Switches	$ 510,902	15,900		$ 526,802	$ (280,401)	(7,437)		$ (287,838)	$ 238,964
47	1835	Overhead Conductors & Devices - Reclosures	$ 446,811			$ 446,811	$ (191,612)	(8,446)		$ (200,058)	$ 246,753
47	1840	Underground Conduit - Duct	$ 1,823,051	641,971		$ 2,465,022	$ (177,505)	(41,113)		$ (218,618)	$ 2,246,404
47	1845	Underground Conductors & Devices - Cable (Non-Duct)	$ 6,252,395			$ 6,252,395	$ (3,135,091)	(174,523)		$ (3,309,614)	$ 2,942,781
47	1845	Underground Conductors & Devices - Cable (In Duct)	$ 2,067,803	570,260		$ 2,638,063	$ (715,832)	(48,562)		$ (764,394)	$ 1,873,669
47	1845	Underground Conductors & Devices - Switchgear	$ 131,598	41,600		$ 173,198	$ (25,860)	(4,884)		$ (30,744)	$ 142,454
47	1850	Line Transformers - Pole Top	$ 10,021,466	499,028		$ 10,520,494	$ (4,132,312)	(202,097)		$ (4,334,409)	$ 6,186,085
47	1850	Line Transformers - Padmount	$ 2,636,571	178,699		$ 2,815,270	$ (757,096)	(58,864)		$ (815,960)	$ 1,999,310
47	1850	Line Transformers - Step-Down (Rabbits)	$ 375,595	29,250		$ 404,845	$ (98,787)	(8,550)		$ (107,337)	$ 297,508
47	1850	Line Transformers - Spare Capital	$ 213,830			$ 213,830	$ -			$ -	$ 213,830
47	1855	Services - Overhead	$ 1,094,794	113,572		$ 1,208,366	$ (308,138)	(15,798)		$ (323,936)	$ 884,430
47	1855	Services - Underground	$ 1,828,941	136,725		$ 1,965,666	$ (580,577)	(48,152)		$ (628,729)	$ 1,336,937
47	1860	Meters - Primary Metering Units	$ 139,449	77,540		$ 216,989	$ (29,043)	(9,012)		$ (38,055)	$ 178,934
47	1860	Meters - Interval Meters & Other Metering Equipment	$ 1,163,484	34,660		$ 1,198,144	$ (368,932)	(192,515)		$ (561,447)	$ 636,697
47	1860	Meters - Smart Meters	$ 3,843,152	133,025		$ 3,976,177	$ (1,004,734)	(252,371)		$ (1,257,105)	$ 2,719,072
47	1860	Meters - Stranded Conventional Meters	$ -			$ -	$ -			$ -	$ -
47	1860	Meters - Spare Capital	$ 94,676			$ 94,676	$ -			$ -	$ 94,676
N/A	1905	Land	$ 127,139			$ 127,139	$ -			$ -	$ 127,139
CEC	1612	Land Rights (Formally known as Account 1906)	$ 695,389			$ 695,389	$ (280,612)	(20,720)		$ (301,332)	$ 394,057
1 b	1908	Buildings & Fixtures	$ 2,190,518			$ 2,190,518	$ (519,483)	(51,730)		$ (571,213)	$ 1,619,305
8	1915	Office Furniture & Equipment (10 years)	$ 370,636	5,000		$ 375,636	$ (284,261)	(22,044)		$ (306,305)	$ 69,331
50	1920	Computer Equipment - Hardware	$ 642,220	109,344		$ 751,564	$ (463,918)	(65,786)		$ (529,704)	$ 221,860
50	1611	Computer Software (Formally known as Account 1925)	$ 2,961,069	280,645		$ 3,241,714	$ (2,425,998)	(221,292)		$ (2,647,290)	$ 594,424
10	1930	Transportation Equipment - Bucket Trucks	$ 1,966,603			$ 1,966,603	$ (1,002,062)	(105,859)		$ (1,107,921)	$ 858,682
10	1930	Transportation Equipment - Pickups and Vans	$ 404,487	218,400		$ 622,887	$ (266,326)	(55,172)		$ (321,498)	$ 301,389
10	1930	Transportation Equipment - Trailers	$ 83,837			$ 83,837	$ (53,151)	(2,000)		$ (55,151)	$ 28,686
8	1940	Tools, Shop & Garage Equipment	$ 830,723	67,250		$ 897,973	$ (511,359)	(56,600)		$ (567,959)	$ 330,014
8	1955	Communications Equipment	$ 68,074			$ 68,074	$ (61,802)	(3,861)		$ (65,663)	$ 2,411
47	1995	Contributions & Grants - Wood Poles	$ (827,945)	(38,153)		-$ 866,098	$ 198,330	14,792		$ 213,122	$ (652,976)
47	1995	Contributions & Grants - Metal / Concrete Poles	$ -			$ -	$ -	0		$ -	$ -
47	1995	Contributions & Grants - O/H Conductor	$ (212,202)	(5,254)		-$ 217,456	$ 43,701	3,863		$ 47,564	$ (169,892)
47	1995	Contributions & Grants - O/H Line Switches	$ (8,391)			-$ 8,391	$ 1,889	167		$ 2,056	$ (6,335)
47	1995	Contributions & Grants - O/H Reclosures	$ (7,345)			-$ 7,345	$ 1,674	167		$ 1,841	$ (5,504)
47	1995	Contributions & Grants - U/G Conduit	$ (420,246)	(16,303)		-$ 436,549	$ 72,830	7,820		$ 80,650	$ (355,899)
47	1995	Contributions & Grants - U/G Conductor (Non-Duct)	$ (1,081,893)			-$ 1,081,893	$ 297,721	34,702		$ 332,423	$ (749,470)
47	1995	Contributions & Grants - U/G Conductor (In Duct)	$ (552,992)	(166,761)		-$ 719,753	$ 68,404	15,293		$ 83,697	$ (636,056)
47	1995	Contributions & Grants - Pole Top Transformers	$ (699,676)	(31,658)		-$ 731,334	$ 195,051	15,900		$ 210,951	$ (520,383)
47	1995	Contributions & Grants - Padmount Transformers	$ (250,056)	(44,297)		-$ 294,353	$ 50,849	6,297		$ 57,146	$ (237,207)
47	1995	Contributions & Grants - Step-Down Transformers	$ (22,227)			-$ 22,227	$ 6,472	490		$ 6,962	$ (15,265)
47	1995	Contributions & Grants - O/H Services	$ (169,604)	(19,639)		-$ 189,243	$ 42,324	2,555		$ 44,879	$ (144,364)
47	1995	Contributions & Grants - U/G Services	$ (281,734)	(24,179)		-$ 305,913	$ 76,281	7,740		$ 84,021	$ (221,892)
47	1995	Contributions & Grants - Primary Metering Units	$ (156,852)			-$ 156,852	$ 30,390	8,431		$ 38,821	$ (118,031)
47	1995	Contributions & Grants - Intervals & Other Metering Equipment	$ (29,619)	(1,672)		-$ 31,291	$ 9,023	2,875		$ 11,898	$ (19,393)
47	1995	Contributions & Grants - Smart Meters	$ (104,694)	(6,149)		-$ 110,843	$ 31,168	10,094		$ 41,262	$ (69,581)
	etc.										
		Sub-Total	**$ 75,039,623**	**$ 5,978,918**	**$ -**	**$ 81,018,541**	**$ (30,285,402)**	**$ (2,117,957)**	**$ -**	**$ (32,403,359)**	**$ 48,615,182**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	**$ -**
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	**$ -**
		Total PP&E	**$ 75,039,623**	**$ 5,978,918**	**$ -**	**$ 81,018,541**	**$ (30,285,402)**	**$ (2,117,957)**	**$ -**	**$ (32,403,359)**	**$ 48,615,182**

Less: CDM-OPA Allocated Costs - *Depreciation Expense*

Building	$ 916
Office Equipment	$ 390
Computer Hardware	$ 1,164
Computer Software	$ 1,499
Net Depreciation Expense	**$ (2,113,988)**

Table 16
Gross Asset by Function with Variances

Description	2010 Board Approved ($)	2010 Actual ($)	Variance from 2010 Board Approved	2011 Actual ($)	Variance from 2010 Actual	2012 Actual ($)	Variance from 2011 Actual	2013 Bridge Year ($)	Variance from 2012 Actual	2014 Test Year ($)	Variance from 2013 Bridge Year
Land and Buildings											
1905-Land	139,071	139,071	-	131,279	(7,792)	127,139	(4,140)	127,139	-	127,139	-
1906-Land Rights	695,389	695,389	-	695,389	0	695,389	-	695,389	-	695,389	-
Sub-Total-Land and Buildings	834,460	834,460	-	826,668	(7,792)	822,528	(4,140)	822,528	-	822,528	-
Distribution Stations											
1609-Distribution Station (below 50 kV) - Capital Contribution Paid	-		-		-		-	29,835	29,835	471,510	441,675
1820-Distribution Station Equipment-Normally Primary below 50 kV	580,903	466,497	(114,406)	466,497	-	466,497	-	466,497	-	471,497	5,000
Sub-Total-Distribution Stations	580,903	466,497	(114,406)	466,497	-	466,497	-	496,332	29,835	943,007	446,675
Poles and Wires											
1830-Poles, Towers and Fixtures	17,504,451	17,784,446	279,995	19,408,683	1,624,237	20,627,452	1,218,769	22,535,283	1,907,831	24,150,766	1,615,483
1835-Overhead Conductors and Devices	9,641,484	10,250,948	609,464	11,757,488	1,506,540	13,556,975	1,799,487	14,805,984	1,249,009	15,939,840	1,133,856
1840-Underground Conduit	973,197	515,163	(458,034)	633,781	118,618	1,366,196	732,415	1,823,051	456,855	2,465,022	641,971
1845-Underground Conductors and Devices	6,918,989	7,130,436	211,447	7,292,189	161,753	7,702,253	410,064	8,451,796	749,543	9,063,656	611,860
Sub-Total-Poles and Wires	35,038,121	35,680,993	642,872	39,092,141	3,411,148	43,252,876	4,160,735	47,616,114	4,363,238	51,619,284	4,003,170
Line Transformers											
1850-Line Transformers	10,957,681	10,962,029	4,348	11,614,068	652,039	12,387,905	773,837	13,247,462	859,557	13,954,439	706,977
Sub-Total-Line Transformers	10,957,681	10,962,029	4,348	11,614,068	652,039	12,387,905	773,837	13,247,462	859,557	13,954,439	706,977
Services and Meters											
1855-Services	2,529,709	2,379,217	(150,492)	2,551,801	172,584	2,683,092	131,291	2,923,735	240,643	3,174,032	250,297
1860-Meters	2,861,710	2,949,488	87,778	3,131,706	182,218	6,758,883	3,627,177	5,240,761	(1,518,122)	5,485,986	245,225
Sub-Total-Services and Meters	5,391,419	5,328,705	(62,714)	5,683,507	354,802	9,441,975	3,758,468	8,164,496	(1,277,479)	8,660,018	495,522
General Plant											
1908-Buildings and Fixtures	2,013,342	2,029,926	16,584	2,168,016	138,090	2,190,518	22,502	2,190,518	-	2,190,518	-
Sub-Total-General Plant	2,013,342	2,029,926	16,584	2,168,016	138,090	2,190,518	22,502	2,190,518	-	2,190,518	-
IT Assets											
1920-Computer Equipment - Hardware	564,322	538,923	(25,399)	517,537	(21,386)	585,095	67,558	642,220	57,125	751,564	109,344
1925-Computer Software	2,621,977	2,460,020	(161,957)	2,584,483	124,463	2,765,069	180,586	2,961,069	196,000	3,241,714	280,645
Sub-Total-IT Assets	3,186,299	2,998,943	(187,356)	3,102,020	103,077	3,350,164	248,144	3,603,289	253,125	3,993,278	389,989
Equipment											
1915-Office Furniture and Equipment	351,584	346,626	(4,958)	363,142	16,516	365,636	2,494	370,636	5,000	375,636	5,000
1930-Transportation Equipment	2,045,683	1,870,374	(175,309)	2,087,570	217,196	2,207,646	120,076	2,454,927	247,281	2,673,327	218,400
1940-Tools, Shop and Garage Equipment	554,868	649,122	94,254	707,839	58,717	795,038	87,199	830,723	35,685	897,973	67,250
1955-Communication Equipment	66,281	64,709	(1,572)	68,074	3,365	68,074	-	68,074	-	68,074	-
Sub-Total-Equipment	3,018,416	2,930,831	(87,585)	3,226,625	295,794	3,436,394	209,769	3,724,360	287,966	4,015,010	290,650
Other Distribution Assets											
1995-Contributions and Grants - Credit	(2,855,819)	(3,786,815)	(930,996)	(3,953,284)	(166,469)	(4,143,672)	(190,388)	(4,825,476)	(681,804)	(5,179,541)	(354,065)
Sub-Total-Other Distribution Assets	(2,855,819)	(3,786,815)	(930,996)	(3,953,284)	(166,469)	(4,143,672)	(190,388)	(4,825,476)	(681,804)	(5,179,541)	(354,065)
Total Gross Assets	58,164,822	57,445,569	(719,253)	62,226,258	4,780,689	71,205,185	8,978,927	75,039,623	3,834,438	81,018,541	5,978,918

VARIANCE ANALYSIS ON GROSS ASSETS

The Gross Asset Variance analysis for those material variances highlighted in Table 16 in Tab 2, Schedule 2 is provided as follows:

2010 Actual versus 2010 Board Approved:

Account 1820 – Distribution Station Equipment $(114,406)

This entire variance is on account of the Nanticoke Distribution Station ("DS"). This DS was dismantled in 2010 and removed from HCHI's books with accumulated depreciation in the amount of $108,160 and a net book value of $6,246.

Construction Projects $642,872 - Accounts as follows:

1830 – Poles, Towers & Fixtures $279,995
1835 – Overhead (O/H) Conductors and Devices $609,464
1840 – Underground (U/G) Conduit $(458,034)
1845 – Underground (U/G) Conductors and Devices $211,447

One contributor to the variance between 2010 Actual and 2010 Board Approved was on account of the Pole Replacement Program capital project. HCHI had originally forecast to spend in the order of $500,000 as included with its 2010 COS rate application but in actual fact spent over $1,000,000 on this project. Two other capital projects originally included in the 2010 Board Approved were cancelled, with the funds reallocated to the Pole Replacement program, which account for a portion of the additional spending but costs were also incurred for the assumption of subdivision assets in the order of $185,000 for 2010 and $433,000 for 2009 that offset this reallocation as they were not forecast in the opening and closing 2010 Board Approved expenditures. An additional contributor to the overall increase was in the Betterments and Line Extensions categories. 2010 Actual spending on Betterments and Line Extensions totaled approximately $187,000 more than the 2010 Board Approved. This category is forecasted by trending historical expenditures. The 2010 Actual expenditures were

higher than the historical years. These types of projects are driven by customer connections (new services and upgrades), safety issues or maintenance activities which are too large to be considered as part of OM&A.

Account 1855 – Services (Overhead and Underground) $(150,492)

The decrease in new service connections in the 2010 Actual versus the 2010 Board Approved is on account of lower than anticipated new customer connections in 2010. Although HCHI connected 248 customers in 2010, 81 of these were related to the conversion of an apartment block from bulk service to individual accounts and when removed from the count, HCHI connected a total of 167 new customers in 2010.

Account 1860 – Meters $87,778

The increase in meters in the 2010 Actual versus the 2010 Board Approved is on account of purchases in 2009 that are not accounted for in the opening or closing balance of the Meter capital in the 2010 COS rate application. Primary metering units were assumed (i.e. purchased) from Hydro One on account of the eight embedded distributor points and from a wind farm in HCHI's service territory for an approximate total value of $152,000. This total increase is offset by the underspend in HCHI's 2010 actual meter capital in the order of $69,000. This underspend is on account of the General Service 50 to 4999 kW meter installs that did not occur at the magnitude projected in the 2010 COS rate application.

Account 1925 – Computer Equipment – Software $(161,957)

The entire decrease in this category is on account of the Asset Management Software System being deferred from the 2010 Actual capital spend. This item was included in the 2010 Board Approved in the amount of $198,000.

Account 1930 – Transportation Equipment $(175,309)

This decrease is mainly on account of the two bucket truck disposals in 2010 Actual that were not included in the 2010 Board Approved in the amount of $165,107.

Account 1940 – Tools, Shop and Garage Equipment $94,254

The increase in the amount of capital spend on tools in the 2010 Actual versus the 2010 Board Approved is on account of deficiencies that were recognized with many tools HCHI had been using and the amount of tool inventory on vehicles. HCHI took immediate action to ensure all tools met safety requirements for line crews and that all trucks were properly outfitted to operate efficiently. HCHI also purchased Tingle Voltage analyzing equipment, in the order of $21,000, to meet requirements for stray voltage testing and three concentrators to gather data from Line Trackers, in the order of $8,400, to analyze power quality information, all of which were not included in the 2010 Board Approved.

Account 1995 – Contributions and Grants – Credit $(930,996)

The 2010 Board Approved amount for opening and closing balances do not include the contributed capital attributable to developers for the assumption of assets in a subdivision. The actual developer rebates were forecast but the capital cost of the subdivision assets and offsetting capital contribution had not been forecast as these amounts are entirely unknown to HCHI. As discussed in the construction variance, these amount to $433,000 in 2009 and $185,000 in 2010. Another contributor to the variance is the capital contribution for the assumption of assets from the wind farm in HCHI's service territory and the primary metering units for the 8 embedded distributor points of Hydro One totaling approximately $322,000.

2011 Actual versus 2010 Actual:

Construction Projects $4,063,187 - Accounts as follows:

1830 – Poles, Towers & Fixtures $1,624,237

1835 – Overhead (O/H) Conductors and Devices $1,506,540
1840 – Underground (U/G) Conduit $118,618
1845 – Underground (U/G) Conductors and Devices $161,753
1850 – Line Transformers $652,039

Part of this variance, in the order of $2,300,000, is on account of a total construction project increase subsequently approved by HCHI's Board of Directors. A majority of this was on account of a specific project approved for an area in HCHI's service territory that was experiencing reliability and power quality issues on a regular basis. This capital project was the 27M5 Feeder Extension in Caledonia (3-Phase project). The remaining variance is on account of the construction projects undertaken in 2011 as described in detail in HCHI's Capital Expenditure Plan (2009 to 2013) ("CEP-2009 to 2013") (refer to Appendix J of its HCHI's DSP).

Account 1855 – Services $172,584

HCHI's spending on new services increased in 2011 Actual versus 2010 Actual due to the number of new customer connections increasing to 265 in 2011 from 167 in 2010.

Account 1860 – Meters $182,218

The increase in meter spending in 2011 Actual versus 2010 Actual is partially related to the General Service 50 to 4999 kW meters that were targeted for installation in 2010 but did not occur until 2011. Another contributor to the increased capital spend is the upgrade of existing services to 3 element meters where feasible. HCHI also experienced an increase in its spare meter capital on account of primary metering units that HCHI needed in its reserve.

Account 1908 – Buildings and Fixtures $138,090

Various renovations and system upgrades to the building at HCHI's head office/service centre in Caledonia, ON occurred in 2011, including: (i) a sliding gate operator to

address security concerns with property access and asset protection; (ii) renovations in the Operations department area; (iii) installation of a roll-up garage door to replace defective equipment; and (iv) new pallet racking in the stores / warehouse area to address safety and loading issues with the existing racking system identified by the Joint Health & Safety Committee and further confirmed by an independent Professional Engineer.

Account 1925 – Computer Equipment – Software $124,463

In 2011 Actual, investments were targeted for the ESRI Distribution Mapping System, a version upgrade to the financial reporting software, upgrades to the server operating systems, and custom reporting in the billing software.

Account 1930 – Transportation Equipment $217,196

2011 Actual capital spend consisted of the new bucket truck aerial device to be installed on its chassis that had been purchased in 2010. HCHI has implemented a fleet management plan and given the nature of the larger vehicle purchases, the spending will occur over a two year period.

Account 1995 – Contributions and Grants – Credit $(166,469)

Capital contributions include contributions from customers on account of line extensions for connecting new services, contributions from developers for subdivision developments, and contributions required from existing customers for service upgrades as per HCHI's Conditions of Service. The majority of these are unpredictable year over year. One evaluation was completed for subdivisions in 2011.

2012 Actual versus 2011 Actual:

Construction Projects $4,934,572 - Accounts as follows:

1830 – Poles, Towers & Fixtures $1,218,769

1835 – Overhead (O/H) Conductors and Devices $1,799,487

1840 – Underground (U/G) Conduit $732,415

1845 – Underground (U/G) Conductors and Devices $410,064

1850 – Line Transformers $773,837

The variance represents HCHI's actual capital investment in construction projects for the year 2012. As discussed in the 2011 Actual, one major construction project that occurred was the 27M5 Feeder Extension in Caledonia, with Phase 2 of 3 being completed in 2012 contributing in the order of $1,500,000 to the 2012 Actual capital spend. An additional $200,000 was on account of carryover from 2011 from Phase 1 of this capital project. Additional project details are included in HCHI's CEP-2009 to 2013 (refer to Appendix J of the DSP).

Account 1855 – Services $131,291

HCHI's spending on new services decreased in 2012 Actual versus 2011 Actual due to the number of new customer connections decreasing to 207 in 2012 from 265 in 2011.

Account 1860 – Meters $3,627,177

The 2012 Actual increase is on account of the disposition approved as part of HCHI's Smart Meter Cost Recovery rate application (EB-2012-0272) in the amount of $3,682,120. The offsetting decrease of $54,943 is on account of the transfer of General Service 50 to 4999 kW smart meters installed in 2011 to the smart meter deferral accounts in order to be included in HCHI's smart meter application for approved disposition and calculation of smart meter rate riders for this customer class.

Account 1920 – Computer Equipment – Hardware $67,558

The 2012 Actual increase is mainly due to the disposition approved as part of HCHI's Smart Meter Cost Recovery rate application (EB-2012-0272) in the amount of $51,094. In addition to this, capital investments were made in 2012 for a plotter / scanner to replace an obsolete plotter, and laptop and server replacements.

Account 1611 (formerly account 1925) – Computer Equipment – Software $180,586

The 2012 Actual increase is mainly due to the disposition approved as part of HCHI's Smart Meter Cost Recovery rate application (EB-2012-0272) in the amount of $62,416. In addition to this, capital investments were made in 2012 for website design, Time-of-Use ("TOU") web access licenses for customers, and upgrades to the financial reporting software.

Account 1930 – Transportation Equipment $120,076

In 2012, HCHI initiated the purchase of a radial boom derrick (i.e. chassis only) to replace an old bucket truck with the balance (i.e. body and aerial device) of the purchase to occur in 2013. The balance of the capital expenditures in this category is for the purchase of a new pickup truck and metering van.

Account 1940 – Tools, Shop and Garage Equipment $87,199

HCHI's 2012 investment in tools for the execution of everyday tasks include: (i) Data Pac devices for communications to the Line Trackers; (ii) a cross-phase circuit analyser for Meter Technicians to verify complex meter installations; (iii) a Fault Wizard locator to locate high resistance faults on underground primary cables; (iv) an additional 5 defibrillators for Operations trucks; and (v) communication devices for Fault Indicators for automatic notification of distribution system faults**.**

Account 1995 – Contributions and Grants – Credit $(190,388)

Capital contributions include contributions from customers on account of line extensions for connecting new services, contributions from developers for subdivision developments, and contributions required from existing customers for service upgrades as per HCHI's Conditions of Service. The majority of these are unpredictable year over year. One evaluation was completed for subdivisions in 2012.

2013 Bridge Year versus 2012 Actual:

Construction Projects - $5,222,795 Accounts as follows:

1830 – Poles, Towers & Fixtures $1,907,831
1835 – Overhead (O/H) Conductors and Devices $1,249,009
1840 – Underground (U/G) Conduit $456,855
1845 – Underground (U/G) Conductors and Devices $749,543
1850 – Line Transformers $859,557

The variance represents HCHI's actual capital investment in construction projects for the year 2013. One major project contributing to the total investment is the "Conversion of Highway #54 to 27.6 kV" in the order of $1,147,000. Two other major capital projects contributing to the variance are the "Conversion to 27.6 kV, Stromness (overloaded step-down transformer)" in the amount of $450,000 and "Conversion to 27.6 kV, Orkney, Inverness, Sutherland St, Caledonia" in the amount of $407,000. The balance of the construction project capital investment in 2013 is detailed in HCHI's CEP-2009 to 2013, (refer to Appendix J of the DSP) along with specific project details for those listed above.

Account 1855 – Services $240,643

HCHI's spending on new services is forecasted to increase in 2013 as compared to 2012 Actual. Services are expected to continue to increase reflecting an upward trend since 2009 even though the increase in services is still budgeted below 2006 levels. 2013 levels have been based on the forecast completed for 2012's budget preparation which is intended to represent an increase in economic activity and the continued implementation of GEA connections.

Account 1860 – Meters $(1,518,122)

The 2013 Bridge Year decrease includes the removal of the stranded conventional meters, in the amount of $1,666,572, from the gross asset pool and transferred to a

sub-account of 1555 for request for disposition as part of this Application. Refer to Exhibit 9, Tab 3, Schedule 1 for details. The remaining difference between the stranded meter disposition and the total variance is on account of annual meter installations. The 2013 Bridge Year also includes a quantity of meters with Zigbee communication protocol for installation on accounts that participate in the Conservation and Demand Management ("CDM") programs. The Zigbee protocol enables the use of an "in home display" for customers to monitor their real time usage.

Account 1611 (formerly account 1925) – Computer Equipment – Software $196,000

For the 2013 Bridge Year, HCHI has included the installation of (i) a bar-code reading system for inventory and the stock room; (ii) cable locate management software for integration to the Ontario OneCall system; and (iii) integration of systems for outage management and reporting.

Account 1930 – Transportation Equipment $247,281

The 2013 Test Year includes the remaining portion of the radial boom derrick chassis purchase initiated in 2012, including the body and aerial device, and the purchase of an additional pickup truck for use by the Engineering staff.

Account 1995 – Contributions and Grants – Credit $(681,804)

Capital contributions include contributions from customers on account of line extensions for connecting new services, contributions from developers for subdivision developments, and contributions required from existing customers for service upgrades as per HCHI's Conditions of Service. The majority of these are unpredictable year over year. Six evaluations are forecasted to be done for subdivision completion in 2013. An additional capital contribution forecast in 2013 is on account of the capital project "Lakeshore Road Conversion – Haldimand Rd 50 to Bookers Road – Phase 2". This project was a coordinated effort with the Grand Renewable Energy Park ("GREP") project, and GREP contributed $200,000 towards this project.

2014 Test Year versus 2013 Bridge Year:

Account 1609 – Distribution Station Equip. – Capital Contribution Paid $441,675

This entire 2014 Test Year variance is on account of the projected purchase of one new 27.6 kV feeder breaker position (M3) at the Hydro One owned Dunnville Transformer Station ("TS") to supply HCHI's forecasted increased load. HCHI is responsible for the costs of providing and installing the feeder to connect to Hydro One's breaker position, as well as the revenue metering outside of the TS. The Connection and Cost Recovery Agreement ("CCRA") – Mini was executed on October 7, 2013. Refer to capital spend details in Table 9 included in Tab 2, Schedule 1 of this Exhibit.

Construction Projects $4,710,147 - Accounts as follows:

1830 – Poles, Towers & Fixtures $1,615,483
1835 – Overhead (O/H) Conductors and Devices $1,133,856
1840 – Underground (U/G) Conduit $641,971
1845 – Underground (U/G) Conductors and Devices $611,860
1850 – Line Transformers $706,977

The variance represents HCHI's actual investment in construction projects for the 2014 Test Year. One major project contributing to the total investment is the "Conversion of Step-Down Transformer on Fisherville Road" in the order of $800,000. Two other major capital projects contributing to the variance are the "Talbot Street, Cayuga – Road Reconstruction" in the amount of $500,000 and "Caithness Street, Caledonia - Road Re-construction" in the order of $650,000. The balance of the construction project capital investment in 2014 is detailed in HCHI's Capital Expenditure Plan (2014 to 2018) ("CEP-2014 to 2018") (refer to Appendix K of the DSP) along with specific project details for those listed above.

Account 1855 – Services $250,297

Services, including both new and upgrades to existing are expected to continue to increase in the 2014 Test Year reflecting an upward trend since 2009. The increase in services is still budgeted below 2006 levels. 2014 levels have been based on the forecast completed for 2012 and estimated 2013 budget preparation which represents an increase in economic activity and the continued implementation of GEA connections.

Account 1860 – Meters $245,225

The 2014 Test Year capital investment in this category continues to represent HCHI's projected capital spending for new meter installs for new services, single phase and three phase services.

Account 1920 – Computer Equipment – Hardware $109,344

Capital investment continues in 2014 as part of HCHI's Information Technology 5 year plan and strategy. Expenditures include server replacements, storage devices, back-up technology, workstation replacements, wireless points, and firewalls.

Account 1611 (formerly account 1925) – Computer Equipment – Software $280,645

2014 Test Year capital spending has been targeted for (i) software compatible with HCHI's financial reporting software that will integrate budgeting, forecasting, financial consolidations and management reporting capabilities; (ii) billing system ad-hoc reports; (iii) an additional module for the financial reporting software to automate timesheets; (iv) replacement of the telephone system; and (v) system integration expenditures between HCHI's four critical software applications, including: (i) Harris Northstar customer information system; (ii) Microsoft Great Plains financial reporting system; (iii) ESRI GIS Mapping system; and (iv) Smart Assistant Operation Data Store system.

Account 1930 – Transportation Equipment $218,400

The 2014 Test Year capital expenditures are for the replacement of two Engineering pick-up trucks and two Operations "on-call" pickup trucks. The annual review of the fleet is based on the age of truck(s), evaluation of trucks using a matrix established in 2008, a detailed assessment of the truck condition and an assessment of future and current needs.

Account 1940 – Tools, Shop and Garage Equipment $67,250

The 2014 Test Year capital expenditures include: (i) a Servisavor unit for temporary restoration of power for customers that have a failed conductor; (ii) the replacement of a power sweeper for the shop and warehouse; and (iii) a tensioner for stringing primary conductor under tension.

Account 1995 – Contributions and Grants – Credit $(354,065)

Capital contributions include contributions from customers on account of line extensions for connecting new services, contributions from developers for subdivision developments, and contributions required from existing customers for service upgrades as per HCHI's Conditions of Service. The majority of these are unpredictable year over year. One evaluation is forecasted to be done for subdivision completion in 2014.

VARIANCE ANALYSIS ON ACCUMULATED DEPRECIATION

In the 2014 Test Year, HCHI reports an opening balance of accumulated depreciation of $30,285,402 and a closing balance of $32,403,359 for an average value of $31,344,380. HCHI's accumulated depreciation with variances is presented in Table 17 below and in the Fixed Asset Continuity tables in Tab 2, Schedule 1 of this Exhibit.

Changes in accumulated depreciation are directly affected by changes in fixed assets due to additions, the removal of fully depreciated assets from the pooled asset classes, and the disposition of identifiable assets. HCHI's accumulated depreciation has increased at the same pace as HCHI's capital investment year over year; that is, except for the accumulated depreciation increase in 2013 which was substantially lower due to the accounting change for new estimated useful lives effective January 1, 2013 as further described at Tab 5, Schedule 6 of this Exhibit.

HCHI's depreciation expense policy and methodology are provided in Exhibit 4, Tab 3, Schedules 1, 2, and 3.

Table 17
Accumulated Depreciation with Variances

Description	2010 Board Approved ($)	2010 Actual ($)	Variance from 2010 Board Approved	2011 Actual ($)	Variance from 2010 Actual	2012 Actual ($)	Variance from 2011 Actual	2013 Bridge Year ($)	Variance from 2012 Actual	2014 Test Year ($)	Variance from 2013 Bridge Year
Land and Buildings											
1905-Land	-	-	-	-	-	-	-	-	-	-	-
1906-Land Rights	212,502	218,394	5,892	239,115	20,721	259,892	20,777	280,612	20,720	301,332	20,720
Sub-Total-Land and Buildings	212,502	218,394	5,892	239,115	20,721	259,892	20,777	280,612	20,720	301,332	20,720
Distribution Stations											
1609-Distribution Station (below 50 kV) - Capital Contribution Paid	-	-	-	-	-	-	-	332	332	5,903	5,571
1820-Distribution Station Equipment-Normally Primary below 50 kV	253,911	150,789	(103,122)	168,055	17,266	185,350	17,295	193,385	8,035	201,477	8,092
Sub-Total-Distribution Stations	253,911	150,789	(103,122)	168,055	17,266	185,350	17,295	193,717	8,367	207,380	13,663
Poles and Wires											
1830-Poles, Towers and Fixtures	7,524,692	7,539,480	14,788	8,403,354	863,874	9,325,608	922,254	9,614,045	288,437	9,937,715	323,670
1835-Overhead Conductors and Devices	3,128,551	3,132,494	3,943	3,618,951	486,457	4,174,410	555,459	4,400,870	226,460	4,651,176	250,306
1840-Underground Conduit	118,641	98,553	(20,088)	118,996	20,443	147,380	28,384	177,505	30,125	218,617	41,112
1845-Underground Conductors and Devices	3,019,679	3,024,236	4,557	3,352,501	328,265	3,666,462	313,961	3,876,781	210,319	4,104,751	227,970
Sub-Total-Poles and Wires	13,791,563	13,794,763	3,200	15,493,802	1,699,039	17,313,860	1,820,058	18,069,201	755,341	18,912,259	843,058
Line Transformers											
1850-Line Transformers	3,792,105	3,781,751	(10,354)	4,246,092	464,341	4,738,267	492,175	4,988,196	249,929	5,257,706	269,510
Sub-Total-Line Transformers	3,792,105	3,781,751	(10,354)	4,246,092	464,341	4,738,267	492,175	4,988,196	249,929	5,257,706	269,510
Services and Meters											
1855-Services	635,791	626,213	(9,578)	724,980	98,767	830,444	105,464	888,715	58,271	952,666	63,951
1860-Meters	1,073,513	1,077,708	4,195	1,196,056	118,348	2,070,790	874,734	1,402,708	(668,082)	1,856,605	453,897
Sub-Total-Services and Meters	1,709,304	1,703,921	(5,383)	1,921,036	217,115	2,901,234	980,198	2,291,423	(609,811)	2,809,271	517,848
General Plant											
1908-Buildings and Fixtures	366,086	365,792	(294)	416,248	50,456	467,768	51,520	519,483	51,715	571,213	51,730
Sub-Total-General Plant	366,086	365,792	(294)	416,248	50,456	467,768	51,520	519,483	51,715	571,213	51,730
IT Assets											
1920-Computer Equipment - Hardware	476,752	403,950	(72,802)	366,498	(37,452)	395,997	29,499	463,918	67,921	529,704	65,786
1925-Computer Equipment - Software	1,500,878	1,435,984	(64,894)	1,790,777	354,793	2,101,504	310,727	2,425,998	324,494	2,647,290	221,292
Sub-Total-IT Assets	1,977,630	1,839,934	(137,696)	2,157,275	317,341	2,497,501	340,226	2,889,916	392,415	3,176,994	287,078
Equipment											
1915-Office Furniture and Equipment	205,946	202,862	(3,084)	233,220	30,358	261,240	28,020	284,261	23,021	306,305	22,044
1930-Transportation Equipment	1,183,144	940,305	(242,839)	1,061,751	121,446	1,183,300	121,549	1,321,538	138,238	1,484,569	163,031
1940-Tools, Shop and Garage Equipment	305,255	340,134	34,879	395,186	55,052	451,778	56,592	511,359	59,581	567,959	56,600
1955-Communication Equipment	66,282	50,570	(15,712)	54,081	3,511	57,942	3,861	61,802	3,860	65,663	3,861
Sub-Total-Equipment	1,760,627	1,533,871	(226,756)	1,744,238	210,367	1,954,260	210,022	2,178,960	224,700	2,424,496	245,536
Other Distribution Assets											
1995-Contributions and Grants - Credit	(643,600)	(691,354)	(47,754)	(846,180)	(154,826)	(1,007,443)	(161,263)	(1,126,106)	(118,663)	(1,257,292)	(131,186)
Sub-Total-Other Distribution Assets	(643,600)	(691,354)	(47,754)	(846,180)	(154,826)	(1,007,443)	(161,263)	(1,126,106)	(118,663)	(1,257,292)	(131,186)
Total Accumulated Depreciation	23,220,128	22,697,861	(522,267)	25,539,681	2,841,820	29,310,689	3,771,008	30,285,402	974,713	32,403,359	2,117,957

WORKING CAPITAL ALLOWANCE

Overview

HCHI's 2014 Test Year working capital allowance is $7,112,904 and is based on the "13% Allowance Approach" referred to at page 15 and described on page 16 of the Board's Filing Requirements. HCHI has applied the 13% to the sum of the cost of power and controllable expenses (i.e. Operating, Maintenance, Billing and Collecting, Community Relations, Administration and General, and Property Taxes) for the 2014 Test year. The 15% allowance approach, as approved in HCHI's 2010 COS rate application, has been used to calculate the working capital allowance in each of the 2010 Actual, 2011 Actual, 2012 Actual, and the 2013 Bridge Year. Table 2 of this Exhibit summarizes these working capital allowance calculations.

Cost of Power

Table 18 below provides HCHI's details on cost of power for the 2010 Board Approved, 2010 Actual, 2011 Actual, 2012 Actual, 2013 Bridge Year and the 2014 Test Year.

Table 18
Summary of Total Cost of Power

	2010 Board Approved	2010 Actual	2011 Actual	2012 Actual	2013 Bridge Year	2014 Test Year
Power	23,063,072	29,560,190	32,075,433	32,783,071	37,161,185	37,764,102
Wholesale Market Service Charges	2,400,175	2,909,386	2,925,537	2,073,930	2,078,700	2,495,692
Network Charges	1,940,566	2,490,966	2,788,020	2,703,951	2,825,564	3,047,987
Connection Charges	1,748,653	2,287,906	2,455,299	2,252,196	2,293,172	2,365,154
Low Voltage Charges	189,793	191,013	136,552	82,392	127,927	137,307
Smart Meter Entity Charges					132,512	197,916
Total Cost of Power	**29,342,259**	**37,439,461**	**40,380,841**	**39,895,540**	**44,619,060**	**46,008,158**

The cost of power for the 2014 Test Year was calculated in accordance with the Filing Requirements and incorporates the load forecast, revised loss factor and increased cost of power rates. The commodity price estimate used to calculate the cost of power was determined by using a split between Regulated Price Plan ("RPP") and non-RPP

customers, based on actual historical data, and using the most current RPP (TOU) price established for May 1, 2013. The rate used for the 2010 Board Approved was $0.06215 per kWh as compared to the current TOU weighted average rate of $0.08395, which represents a rate increase of 35%.

HCHI's calculations also incorporate the most recent Uniform Transmission Rates approved by the Board (EB-2012-0031) and the Hydro One Transmission Rates approved by the Board (EB-2012-0136), both effective January 1, 2013.

The Smart Meter Entity charge, approved by the Board on March 28, 2013 in its EB-2012-0100 / EB-2012-0211 Decision and Order, has also been incorporated into the cost of power calculations.

HCHI has also used the approved rates for the other components of the cost of power calculation, specifically the Wholesale Market Service charge and Rural or Remote Protection Plan charge as approved by the Board (EB-2013-0067) effective May 1, 2013 and the Low Voltage Charges as approved by the Board in the Hydro One's Distribution Rate Application (EB-2012-0136) for rates effective January 1, 2013.

The following Table 19 provides details of HCHI's cost of power calculations for the 2014 Test Year using the 2014 proposed load forecast discussed in further detail in Exhibit 3, Tab 2, Schedule 2.

Table 19
2014 Test Year Cost of Power Calculations

2014 Load Foreacst	**kWh**	**kW**	**2012 %RPP**		
Residential	169,003,519		88.29%		
General Service Less Than 50 kW	53,925,141		72.88%		
General Service 50 to 4,999 kW	121,879,907	342,324	7.71%		
Embedded Distributor - Hydro One Networks Inc.	72,629,941	227,715	0.00%		
Street Lighting	2,387,575	6,648	1.28%		
Sentinel Lighting	327,143	909	83.76%		
Unmetered Scattered Loads	350,238		80.82%		
TOTAL	**420,503,464**	**577,596**			

Electricity - Commodity RPP	**2014**	**2014 Loss**			
Class per Load Forecast RPP	**Forecasted**	**Factor**		**2014**	
Residential	149,204,757	1.0663	159,097,032	$0.08395	$13,356,196
General Service Less Than 50 kW	39,300,643	1.0663	41,906,276	$0.08395	$3,518,032
General Service 50 to 4,999 kW	9,399,378	1.0663	10,022,557	$0.08395	$841,394
Embedded Distributor - Hydro One Networks Inc.	0	1.0288	0	$0.08395	$0
Street Lighting	30,442	1.0663	32,460	$0.08395	$2,725
Sentinel Lighting	274,012	1.0663	292,179	$0.08395	$24,528
Unmetered Scattered Loads	283,062	1.0663	301,829	$0.08395	$25,339
TOTAL	**198,492,294**		**211,652,333**		**$17,768,213**

Electricity - Commodity Non-RPP	**2014**	**2014 Loss**			
Class per Load Forecast	**Forecasted**	**Factor**		**2014**	
Residential	19,798,762	1.0663	21,111,420	$0.01933	$408,084
General Service Less Than 50 kW	14,624,498	1.0663	15,594,102	$0.01933	$301,434
General Service 50 to 4,999 kW	112,480,529	1.0663	119,937,988	$0.01933	$2,318,401
Embedded Distributor - Hydro One Networks Inc.	72,629,941	1.0288	74,721,683	$0.01933	$1,444,370
Street Lighting	2,357,133	1.0663	2,513,410	$0.01933	$48,584
Sentinel Lighting	53,131	1.0663	56,654	$0.01933	$1,095
Unmetered Scattered Loads	67,176	1.0663	71,630	$0.01933	$1,385
TOTAL	**222,011,170**		**234,006,888**		**$4,523,353**

Electricity - Global Adjustment Non-RPP	**2014**	**2014 Loss**			
Class per Load Forecast	**Forecasted**	**Factor**		**2014**	
Residential	19,798,762	1.0663	21,111,420	$0.06612	$1,395,887
General Service Less Than 50 kW	14,624,498	1.0663	15,594,102	$0.06612	$1,031,082
General Service 50 to 4,999 kW	112,480,529	1.0663	119,937,988	$0.06612	$7,930,300
Embedded Distributor - Hydro One Networks Inc.	72,629,941	1.0288	74,721,683	$0.06612	$4,940,598
Street Lighting	2,357,133	1.0663	2,513,410	$0.06612	$166,187
Sentinel Lighting	53,131	1.0663	56,654	$0.06612	$3,746
Unmetered Scattered Loads	67,176	1.0663	71,630	$0.06612	$4,736
TOTAL	**222,011,170**		**234,006,888**		**$15,472,535**

Transmission - Network	**2014 Loss**	**Volume**			
Class per Load Forecast	**Factor**	**Metric**		**2014**	
Residential		kWh	180,208,452	$0.0065	$1,171,355
General Service Less Than 50 kW		kWh	57,500,378	$0.0058	$333,502
General Service 50 to 4,999 kW		kW	342,324	$2.4800	$848,964
Embedded Distributor - Hydro One Networks Inc.	1.0288	kW	227,715	$2.8960	$678,455
Street Lighting		kW	6,648	$1.7912	$11,908
Sentinel Lighting		kW	909	$1.8003	$1,637
Unmetered Scattered Loads		kWh	373,459	$0.0058	$2,166
TOTAL					**$3,047,987**

Transmission - Connection		**Volume**			
Class per Load Forecast		**Metric**		**2014**	
Residential		kWh	180,208,452	$0.0049	$883,021
General Service Less Than 50 kW		kWh	57,500,378	$0.0045	$258,752
General Service 50 to 4,999 kW		kW	342,324	$1.9031	$651,477
Embedded Distributor - Hydro One Networks Inc.	1.0288	kW	227,715	$2.3898	$559,866
Street Lighting		kW	6,648	$1.3671	$9,088
Sentinel Lighting		kW	909	$1.3957	$1,269
Unmetered Scattered Loads		kWh	373,459	$0.0045	$1,681
TOTAL					**$2,365,154**

Wholesale Market Service					
Class per Load Forecast				**2014**	
Residential			180,208,452	$0.0044	$792,917
General Service Less Than 50 kW			57,500,378	$0.0044	$253,002
General Service 50 to 4,999 kW			129,960,545	$0.0044	$571,826
Embedded Distributor - Hydro One Networks Inc.			74,721,683	$0.0044	$328,775
Street Lighting			2,545,870	$0.0044	$11,202
Sentinel Lighting			348,833	$0.0044	$1,535
Unmetered Scattered Loads			373,459	$0.0044	$1,643
TOTAL			**445,659,221**		**$1,960,901**

Rural Rate Assistance					
Class per Load Forecast				**2014**	
Residential			180,208,452	$0.0012	$216,250
General Service Less Than 50 kW			57,500,378	$0.0012	$69,000
General Service 50 to 4,999 kW			129,960,545	$0.0012	$155,953
Embedded Distributor - Hydro One Networks Inc.			74,721,683	$0.0012	$89,666
Street Lighting			2,545,870	$0.0012	$3,055
Sentinel Lighting			348,833	$0.0012	$419
Unmetered Scattered Loads			373,459	$0.0012	$448
TOTAL			**445,659,221**		**$534,791**

Calculations Per Above	**2014**
4705-Power Purchased	$22,291,567
4707-Global Adjustment	$15,472,535
4708-Charges-WMS	$1,960,901
4714-Charges-NW	$3,047,987
4716-Charges-CN	$2,365,154
4730-Rural Rate Assistance	$534,791
4750-Low Voltage	$137,307
4751-Smart Meter Entity Charge	$197,916
TOTAL	**46,008,157**

TREATMENT OF STRANDED ASSETS RELATED TO SMART METER DEPLOYMENT

Treatment of Stranded Meters

The Board's *Guideline: Smart Meter Funding and Cost Recovery (G-2008-0002)* provides two options to distributors regarding the accounting treatment for stranded meters related to the installation of smart meters; (1) leave them in rate base; or (2) record them in "Sub-account Stranded Meter Costs" of Account 1555. HCHI has accounted for its stranded meter costs using option (1).

HCHI applied for, and was approved for, the disposition and recovery of costs related to Smart Meter deployment, offset by Smart Meter Funding Adder revenues collected from May 1, 2006 to April 30, 2012 (EB-2012-0272). As part of the Smart Meter rate application, and as approved by the Board in its Decision and Order issued November 1, 2012, HCHI proposed not to dispose of stranded meter costs at that time, but to deal with the disposition in its next rebasing application, scheduled for 2014 rates. The Smart Meter rate application, and Decision and Order, noted an estimated net book value of stranded meters for the Residential, General Service Less Than 50 kW, and General Service 50 to 4999 kW customer classes of $439,049 as at December 31, 2013 and that the stranded conventional meters would continue to be amortized until disposition. This estimation of the net book value has now been updated to reflect actual costing information at a net book value of $479,441 as at December 31, 2013.

In accordance with the Board's Guidelines G-2011-0001 *"Smart Meter Funding and Cost Recovery – Final Disposition"* issued December 15, 2011, whereby distributors are to be held whole with respect to the cost recovery of stranded meters (i.e. conventional meters replaced as part of the Smart Meter initiative), HCHI, as part of this rebasing application, is requesting approval to recover its stranded meter costs as at December 31, 2013 through class-specific rate riders from the three applicable customer classes.

As part of this Application, HCHI has transferred the stranded meter costs from "Account 1860 – Meters" to "Sub-account - Stranded Meter Costs" of Account 1555 as at December 31, 2013 and has specifically applied in Exhibit 9 at Tab 3, Schedule 1 for the disposal of the balance in deferral / variance sub-account 1555 – Stranded Meter Costs.

Table 20 provides a summary of the gross costs, accumulated depreciation, net asset costs, proceeds on dispositions, and residual net book value of $479,441 as at December 31, 2013. Table 21 allocates the residual net book value between the three customer classes, Residential, General Service Less Than 50 kW, and General Service 50 to 4999 kW. This information has also been filed as OEB Appendix 2-S "Stranded Meters".

Table 20
Stranded Meter Treatment

Year	Gross Asset Value	Accumulated Depreciation	Contributed Capital (Net of Depreciation)	Net Asset	Proceeds on Disposition	Residual Net Book Value
	(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2009	$ 1,164,668	$ 985,328		$ 179,340		$ 179,340
2010	$ 1,487,164	$ 1,042,811		$ 444,353	$ 3,687	$ 440,666
2011	$ 1,664,167	$ 1,095,973		$ 568,194	$ 3,687	$ 564,508
2012	$ 1,666,572	$ 1,140,139		$ 526,433	$ 4,491	$ 521,942
2013	$ 1,666,572	$ 1,182,640		$ 483,932	$ 4,491	**$ 479,441**

Table 21
Stranded Meter Treatment by Customer Class

Rate Class	Net Book Value of Stranded Asset	Proceeds on Disposition	Residual Net Book Value
Residential	$ 360,013	$ 3,341	$ 356,671
General Service Less Than 50 kW	$ 104,195	$ 967	$ 103,228
General Service 50 to 4,999 kW	$ 19,725	$ 183	$ 19,542
	$ 483,933	**$ 4,491**	**$ 479,441**

Note: Proceeds on Disposition allocated to Customer Classes based on Net Book Value of Stranded Asset

HCHI proposes to recover the net book value of Stranded Meter costs of $479,441 through a customer class-specific rate rider, over a one year period beginning May 1, 2014.

CAPITAL EXPENDITURES

OVERVIEW OF CAPITAL EXPENDITURES

In managing its distribution system assets, HCHI's main objective is to optimize performance of the assets at a reasonable cost with due regard for system reliability, public and employee safety and customer service requirements. This Application incorporates HCHI's 2014 Capital and Operating Budgets in determining its Revenue Requirement to bring these plans to fruition. HCHI considers performance-related asset information including, but not limited to, data on reliability, asset age and condition, loading, customer connection requirements, and system configuration, to determine the investment needs of the system.

HCHI's Distribution System Plan ("DSP") identifies the capital projects required over a 5 year period, 2014 to 2018, based on the best available information for each year. The DSP has been filed as Appendix A to this Exhibit. The capital budget forecast is influenced significantly by condition data that is collected each year on aging infrastructure and as such, HCHI may be required to adjust the capital project forecast as the knowledge of its distribution system needs increases. For major conversion projects to 27.6 kV voltages, the project is broken down into phases of completion with each phase being recorded on the books in the year of completion.

The budget is prepared before the start of each fiscal year by management and is reviewed and approved by HCHI's Board of Directors. Once approved, it typically does not change but provides a plan against which actual results are evaluated.

In addition to the capital needs of the system, HCHI provides for maintenance planning for the assets. The same preparation and consideration steps are undertaken before budget amounts are presented to HCHI's Board of Directors for approval.

HCHI has been and continues to be focused on maintaining the adequacy, reliability and quality of service to its electricity distribution customers. HCHI completes regular

inspections throughout the year while carrying out necessary maintenance of the distribution system.

The reliability indices are recorded and monitored on a monthly basis as demonstrated at Tab 8, Schedule 1 of this Exhibit. The indices are used to assess the condition of assets which impacts the capital budgeting process.

The nature and magnitude of the capital expenditures is in part to address the large portion of the 8 kV system, currently representing 63% of HCHI's entire distribution system. The 8 kV system limits the connection of load and generator connections, is often off road and difficult to access, and is at end-of-life in most areas. These issues also cause poor power quality and reliability when compared to the 27.6 kV system. The five year forecast of capital expenditures address only the areas that are identified as a high priority. The priorities are determined by loading, quantity of customers, and three phase lines. HCHI views this strategy as a long term strategy for the next 10 – 20 years.

HCHI's capital investment strategy is based on the vision and mission to provide efficient, reliable, and safe electricity distribution and other related services to customers and to contribute to the development of our jurisdiction's economy and our employees and the protection of the environment while enhancing the value of the utility. HCHI is of the opinion that investments in distribution infrastructure have, and will continue to have, positive impacts such as improved reliability, improved power quality and improvements to its total loss factor at the same time providing greater access for load and generator customers. These reliability improvements have been realized to date. Ultimately this results in reduced operating and maintenance costs.

Capital expenditure variance analysis can be found in Tab 2, Schedule 3 of this Exhibit with additional discussion on each capital project, historical and forecast, in the DSP (refer to Appendix A).

HCHI has not included any capital expenditures for non-distribution activities in its capital spending for any historical, bridge, or test year.

CAPITAL EXPENDITURES / PROJECTS

Historically, HCHI's assets have fallen into two broad categories. The first category is "distribution plant", which includes assets such as distribution stations, poles, conductor, overhead and underground electricity distribution infrastructure, transformers, and meters. The second category is "general plant" which includes modifications, replacements, or additions to a distributor's assets that are not part of its distribution system - including land, buildings, tools, transportation equipment, computer hardware and software and communication devices - all used to support day to day business and operational activities.

Consistent with Chapter 5 of the Filing Requirements, *"Consolidated Distribution System Plan Filing Requirements"*, issued March 28, 2013, HCHI has further allocated its distribution plant into the Board investment categories, as follows:

A. System Access – defined as modifications (including asset relocation) to a distributor's distribution system a distributor is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system.

B. System Renewal – defined as replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services.

C. System Service – defined as modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements.

HCHI has provided its capital expenditure summary for distribution plant by these three investment categories and its General and Administrative assets in the fourth investment category (D. General Plant) in Table 22 below. This information is also filed as OEB Appendix 2-AB "Capital Expenditures".

Table 22
Capital Expenditure Summary by Investment Category

CATEGORY	Historical Period (Actual)					Forecast Period (Planned)				
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
	Actual	Actual	Actual	Actual	Actual					
	$ '000	*$ '000*	*$ '000*	*$ '000*	*$ '000*	*$ '000*				
System Access	928	1,004	887	4,848	1,644	1,978	1,456	1,330	1,406	1,365
System Renewal	928	1,210	769	498	330	375	950	1,425	1,300	1,350
System Service	1,221	189	2,617	3,203	2,986	2,946	2,200	2,175	2,410	2,100
General Plant	1,114	825	676	651	541	680	698	489	437	464
Total Capital Expenditure	$ 4,191	$ 3,228	$ 4,949	$ 9,200	$ 5,501	$ 5,979	$ 5,304	$ 5,419	$ 5,553	$ 5,279
System O&M	$ 2,909	$ 2,794	$ 3,078	$ 3,158	$ 3,539	$ 3,606	$ 3,664	$ 3,722	$ 3,782	$ 3,842

Notes to the Table:

Notes on shifts in forecast vs. histrical budgets by category

Investments in single pole replacements (System Renewal) as a result of the annual capital project Pole Replacement Program have decreased by approximately 50 - 60 % ($500,000) starting in 2012 as compared to prior years. This is on account of the majority of poles that required immediate replacement have now been completed. Pole inspection cycles are now in their second inspection cycle and the number of very poor poles inspected is less than in prior years.

Notes on year over year Plan vs. Actual variances for Total Expenditures

Not required as a Distribution System Plan has not previously been filed as this is the initial Chapter 5 filing.

HCHI has been, and continues to be, focused on maintaining the adequacy, reliability, and quality of service to its electricity distribution customers through effective capital spending.

HCHI has completed OEB Appendix 2-AA "Capital Projects" with information about capital expenditures on a project-specific basis in two formats. The first format, found in Table 23, includes the capital projects allocated by major function with a column for the investment category beside each project, and the second format, found in Table 24, includes the capital projects allocated by investment category reconciling back to Table 22 above.

The investment categories in Table 23 have been assigned the same letters as can be found in HCHI's DSP, Appendix A, to this Exhibit. They are as follows:

- A – System Access
- B – System Renewal
- C – System Service
- D – General Plant

Table 23
Capital Projects by Function and Investment Category

Projects	Investment Category	2008	2009	2010	2011	2012	2013 Bridge Year	2014 Test Year
Reporting Basis			CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Distribution Stations (1820)								
Dunnville TS Breaker Position	A						29,835	441,675
Dunnville TS Make Ready Work	A							5,000
Sub-Total		0	-	-	-	-	29,835	446,675
Poles, Towers, and Fixtures (1830)								
Dunnville TS Make Ready Work	A							20,000
Pole Replacement Program	B		207,948	552,590	452,783	320,663	167,705	190,574
Moulton-Sherbrooke Townline-Rattlesnake Road Conversion, Dunnville	C		30,818					
Construction of Line from Hagersville to Jarvis	C		12,640					
Conversion of Line from Hagersville to Jarvis	C		69,091					
Conversion of Central Lane Phase II	C		12,774					
Eliminate Selkirk North 8kV Distribution Station	B		70,442					
Purchase Hydro One F2 Feeder out of Argyle Distribution Station	C		23,436					
Lakeshore Road Re-Build (Melville Lane Area)	C		129,767	1,426				
Eliminate Nanticoke Distribution Station (2008 Carryover)	B		518					
Elimate Feeds from Lythmore Distribution Station (Ph.1-East)	B			39,644				
Conversion to Supply Innophos and Sherbrooke Area to 31M1 Feeder	C			53,006				
27M5 Feeder Extension Caledonia (3-phase project)	C				704,463	395,414		
Maple Street, Dunnville - Line Conversion to 27.6 kV	C				472	11,622		
Alder Street, Dunnville - Conversion- Underground Rebuild	C				14,877	64,965	2,929	
Highway #3, Jarvis - Line Conversion from 8 kV to 27.6 kV	C				29,806	309		
27.6 kV Conversion into Cayuga	C				174,194	483		
Conversion to Supply Innophos and Sherbrooke Area to 31M1 Feeder	C				67,475			
Install One Load Break Switch	C				1,972			
Townsend Back-up Feeder	C					148,893	1,440	
Lakeshore Road Conversion - Haldimand Road 50 to Bookers Rd.	C					6,960	95,649	
Contributed Capital - Lakeshore Rd.Conversion (Grand Renewable Energy Park project)	C						(50,000)	
Conversion of Highway #54 to 27.6 kV	C						539,125	
Conversion to 27.6 kV, Stromness (Overloaded Step-down Trx.)	C						274,750	
Conversion to 27.6 kV Orkney, Inverness, Sutherland Streets, Caledonia	C						204,500	
Conversion to 27.6 kV - Kohler Road	C						112,842	
Renewable Energy Cost Cap Investments	A						3,059	76,500
Caithness Street, Caledonia - Road Reconstruction	C							45,500
Conversion of York Village to 27.6 kV	C							142,000
Conversion of Lakeshore Road (West of Kohler to 27.6 kV)	C							194,000
Conversion of Step-down Transformer on Fisherville Road	C							420,000
Partial Conversion of Step-down (SD-37) Transformer, Oneida	C							176,000
Betterments	A		126,868	119,053	38,543	172,956	335,761	177,088
Line Extensions	A		148,505	146,745	139,652	96,506	170,071	173,822
Contributed Capital - Regular	A		(55,025)	(52,400)	(56,270)	(53,226)	(38,153)	(38,153)
Contributed Capital - Subdivisions / Developer Rebates	A							
Assumption of Assets - Subdivisions	A							
Contributed Capital - Other	A		(63,089)	(2,828)				
Assumption of Assets - Other (Wind Farm / HONI Metering Points)	A		63,091	2,828				
Sub-Total		0	777,784	860,064	1,567,967	1,165,545	1,819,678	1,577,331
Overhead Conductor (1835)								
Dunnville TS Make Ready Work	A							15,900
Pole Replacement Program	B		233,654	400,373	272,630	139,902	108,736	123,563
Moulton-Sherbrooke Townline-Rattlesnake Road Conversion, Dunnville	C		41,042					
Construction of Line from Hagersville to Jarvis	C		179,978					
Conversion of Line from Hagersville to Jarvis	C		140,139					
Conversion of Central Lane Phase II	C		107,045					
Eliminate Selkirk North 8kV Distribution Station	B		261,801					
Purchase Hydro One F2 Feeder out of Argyle Distribution Station	C		100,266					
Lakeshore Road Re-Build (Melville Lane Area)	C		137,520	(401)				
Elimate Feeds from Lythmore Distribution Station (Ph.1-East)	B			70,630				
Install One Load Break Switch	C			23,392				
Conversion to Supply Innophos and Sherbrooke Area to 31M1 Feeder	C			66,798				
27M5 Feeder Extension Caledonia (3-phase project)	C				443,353	1,162,296		
Maple Street, Dunnville - Line Conversion to 27.6 kV	C				203	29,542		
Alder Street, Dunnville - Conversion- Underground Rebuild	C				10,086	15,524	359	
Highway #3, Jarvis - Line Conversion from 8 kV to 27.6 kV	C				58,797	510		
27.6 kV Conversion into Cayuga	C				342,801			
Conversion to Supply Innophos and Sherbrooke Area to 31M1 Feeder	C				180,093			
Rebuild of Argyle Street, Caledonia (Sutherland St. to railway)	C						7,010	
Townsend Back-up Feeder	C					136,042	535	
Lakeshore Road Conversion - Haldimand Road 50 to Bookers Rd.	C					20,000	39,416	
Conversion of Highway #54 to 27.6 kV	C						498,344	
Conversion to 27.6 kV, Stromness (Overloaded Step-down Trx.)	C						77,500	
Conversion to 27.6 kV Orkney, Inverness, Sutherland Streets, Caledonia	C						110,500	
Conversion to 27.6 kV - Kohler Road	C						74,828	
Renewable Energy Cost Cap Investments	A						766	76,500
Caithness Street, Caledonia - Road Reconstruction	C							45,500
Conversion of York Village to 27.6 kV	C							102,500
Conversion of Lakeshore Road (West of Kohler to 27.6 kV)	C							170,000
Conversion of Step-down Transformer on Fisherville Road	C							330,000
Partial Conversion of Step-down (SD-37) Transformer, Oneida	C							74,000
Betterments	A		161,472	190,667	85,300	73,646	242,066	104,981
Line Extensions	A		108,893	122,424	113,278	222,024	88,949	90,911
Contributed Capital - Regular	A		(2,103)	(1,788)	(7,821)	(119)	(5,254)	(5,254)
Contributed Capital - Subdivisions / Developer Rebates	A		(50,211)					
Assumption of Assets - Subdivisions	A		68,875					
Contributed Capital - Other	A		(80,810)	(21,282)				
Assumption of Assets - Other (Wind Farm / HONI Metering Points)	A		80,810	21,282				
Sub-Total		0	1,488,371	872,095	1,498,720	1,799,367	1,243,755	1,128,601

Projects	Investment Category	2008	2009	2010	2011	2012	2013 Bridge Year	2014 Test Year
Reporting Basis			CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Underground Conduit (1840)								
Pole Replacement Program	B		2,694	1,471		688	1,658	1,884
Construction of Line from Hagersville to Jarvis	C		847					
Conversion of Central Lane, Dunnville Phase II	C		1,016					
Eliminate Selkirk North 8kV Distribution Station	B		(50)					
Lakeshore Road Re-Build (Melville Lane Area)	C		2,499					
27M5 Feeder Extension Caledonia (3-phase project)	C					1,333		
Maple Street, Dunnville - Line Conversion to 27.6 kV	C				593	3,666		
Alder Street, Dunnville - Conversion- Underground Rebuild	C				116,922	107,454	72,211	
Highway #3, Jarvis - Line Conversion from 8 kV to 27.6 kV	C				2,826	(185)		
27.6 kV Conversion into Cayuga	C				105			
Conversion to Supply Innophos and Sherbrooke Area to 31M1 Feeder	C				150			
Rebuild of Argyle Street, Caledonia (Sutherland St. to railway)	C					277,336	153,416	
Townsend Back-up Feeder	C					30,992	1,022	
Lakeshore Road Conversion - Haldimand Road 50 to Bookers Rd.	C					15,160	176,275	
Contributed Capital - Lakeshore Rd.Conversion (Grand Renewable Energy Park project)	C						(100,000)	
Main & Queen Streets, Dunnville - Road Re-construction	C					139,328		
Conversion to 27.6 kV Orkney, Inverness, Sutherland Streets, Caledonia	C						28,000	
Conversion to 27.6 kV - Kohler Road	C						40	
Caithness Street, Caledonia - Road Reconstruction	C							287,400
York Bridge Duct Installation - Engineering Design	A							15,000
Talbot Street, Cayuga - Road Reconstruction	C							314,000
Betterments	A		18,155	62,154	(10,531)	3,753	3,990	2,998
Line Extensions	A		52,124	669	8,551	152,890	20,243	20,690
Contributed Capital - Regular	A		(26,358)	(29,193)	(34,817)	(33,854)	(16,303)	(16,303)
Sub-Total		0	50,927	35,101	83,799	698,561	340,552	625,669
Underground Conductor (1845)								
Pole Replacement Program	B		14,849	5,779	3,258	10,556		
Conversion of Central Lane, Dunnville Phase II	C		3,889					
Eliminate Selkirk North 8kV Distribution Station	B		14,580					
Lakeshore Road Re-Build (Melville Lane Area)	C		9,437					
Elimate Feeds from Lythmore Distribution Station (Ph.1-East)	B			1,409				
Alder Street, Dunnville - Conversion- Underground Rebuild	C			27,097	79,661	101,211	71,451	
27M5 Feeder Extension Caledonia (3-phase project)	c					24,228		
Maple Street, Dunnville - Line Conversion to 27.6 kV	C					13,421		
27.6 kV Conversion into Cayuga	C				4,760			
Rebuild of Argyle Street, Caledonia (Sutherland St. to railway)	C				3,750	40,854	(3,425)	
Townsend Back-up Feeder	C					29,236	76,555	
Lakeshore Road Conversion - Haldimand Road 50 to Bookers Rd.	C					22,740	151,369	
Contributed Capital - Lakeshore Rd.Conversion (Grand Renewable Energy Park project)	C						(50,000)	
Conversion to 27.6 kV Orkney, Inverness, Sutherland Streets, Caledonia	C						26,500	
Caithness Street, Caledonia - Road Reconstruction	C							206,600
York Bridge Duct Installation - Engineering Design	A							5,000
Talbot Street, Cayuga - Road Reconstruction	C							136,500
Betterments	A		3,435	13,598		61,421	113,719	85,426
Line Extensions	A		7,043	60,728	70,324	72,821	4,655	4,758
Contributed Capital - Regular	A		(36,826)	(41,612)	(39,944)	(50,110)	(46,994)	(46,994)
Contributed Capital - Subdivisions / Developer Rebates	A		(189,126)	(71,032)	10,437	4,370	(213,016)	(119,767)
Assumption of Assets - Subdivisions	A		249,130	151,954		33,575	308,719	173,575
Sub-Total		0	76,411	147,921	132,246	364,323	439,533	445,098
Transformers (1850)								
Pole Replacement Program	B		49,597	66,117	40,528	26,627	51,901	58,979
Moulton-Sherbrooke Townline-Rattlesnake Road Conversion, Dunnville	C		42,652					
Construction of Line from Hagersville to Jarvis	C		107,081					
Conversion of Line from Hagersville to Jarvis	C		5,809					
Conversion of Central Lane, Dunnville Phase II	C		27,984					
Eliminate Selkirk North 8kV Distribution Station	B		71,483					
Lakeshore Road Re-Build (Melville Lane Area)	C		35,631					
Elimate Feeds from Lythmore Distribution Station (Ph.1-East)	B			72,518				
Conversion to Supply Innophos and Sherbrooke Area to 31M1 Feeder	C			17,148				
27M5 Feeder Extension Caledonia (3-phase project)	C				126,713	115,485		
Maple Street, Dunnville - Line Conversion to 27.6 kV	C				16,995	86,679		
Alder Street, Dunnville - Conversion- Underground Rebuild	C				49,206	115,332	(4,951)	
Highway #3, Jarvis - Line Conversion from 8 kV to 27.6 kV	C				31,984			
27.6 kV Conversion into Cayuga	C				80,876	1,844		
Conversion to Supply Innophos and Sherbrooke Area to 31M1 Feeder	C				73,794			
Rebuild of Argyle Street, Caledonia (Sutherland St. to railway)	C					5,618	(5,000)	
Townsend Back-up Feeder	C					49,639		
Lakeshore Road Conversion - Haldimand Road 50 to Bookers Rd.	C					30,000	112,291	
Conversion of Highway #54 to 27.6 kV	C						109,530	
Conversion to 27.6 kV, Stromness (Overloaded Step-down Trx.)	C						97,750	
Conversion to 27.6 kV Orkney, Inverness, Sutherland Streets, Caledonia	C						37,500	
Conversion to 27.6 kV - Kohler Road	C						46,087	
Caithness Street, Caledonia - Road Reconstruction	C							65,000
Conversion of York Village to 27.6 kV	C							55,500
Dunnville TS Make Ready Work	A							4,000
Conversion of Lakeshore Road (West of Kohler to 27.6 kV)	C							32,000
Conversion of Step-down Transformer on Fisherville Road	C							50,000
Partial Conversion of Step-down (SD-37) Transformer, Oneida	C							50,000
Talbot Street, Cayuga - Road Reconstruction	C							49,500
Betterments	A		51,642	58,377	121,549	123,409	107,392	80,673
Line Extensions	A		199,073	215,404	179,651	210,641	192,872	197,127
Spare Transformer Capital			(37,588)	19,904	(69,257)	(3,740)		
Contributed Capital - Regular	A		(601)	(80,996)	(3,265)	(47,267)	(31,658)	(31,658)
Contributed Capital - Subdivisions / Developer Rebates	A		(81,689)	(7,670)	2,291	3,266	(78,787)	(44,297)
Assumption of Assets - Subdivisions	A		115,212	34,026		12,303	114,184	64,199
Sub-Total		0	586,286	394,828	651,065	729,836	749,111	631,023

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Projects	Investment Category	2008	2009	2010	2011	2012	2013 Bridge Year	2014 Test Year
Reporting Basis			CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Overhead / Underground Services (1855)								
Overhead Services	A		46,436	50,286	71,123	48,224	110,516	111,072
Underground Services	A		56,127	74,677	101,461	83,067	130,127	136,725
Dunnville TS Make Ready Work	A							2,500
Contributed Capital - Regular	A		(31,912)	(7,825)	(16,925)	(1,422)	(43,818)	(43,818)
Sub-Total		0	70,651	117,138	155,659	129,869	196,825	206,479
Meters (1860)								
Primary Meter Services	A		(7,536)	7,820	91,603	(30,565)	19,000	36,440
Secondary Meter Services	A		7,419	3,838	42,438	18,166	129,450	149,185
Meters - Smart Meter Disposition (EB-2012-0272)	A					3,682,120		
Dunnville TS Make Ready Work	A							59,600
Spare Meter Capital			35,138	8,952	48,176	(40,893)		
Contributed Capital - Regular	A		(5,294)	(16,265)	(20,155)	(12,025)	(7,821)	(7,821)
Contributed Capital - Other	A		(156,852)	2,392				
Assumption of Assets - Other (Wind Farm / HONI Metering Points)	A		151,501	(2,392)				
Sub-Total		0	24,376	4,345	162,062	3,616,803	140,629	237,404
General Plant								
Buildings and Fixtures (1908)								
Building and Fixtures - Heat Trace Cabling, Storage/Pallet Racking, Floor Trenches, Overhead Garage Doors, Office Renovations, Lockers	D		6,414	32,033	138,090	22,502		
Computer Equipment - Hardware (1920)								
Computer Hardware - Workstations, Servers, Laptops, Ipads, etc.	D		43,352	69,180	75,941	67,895	57,125	109,344
Computer Hardware - Smart Meter Disposition (EB-2012-0272)	D					51,094		
Computer Equipment - Software (1611 - formerly account 1925)								
Computer Software - ESRI Mapping System	D		191,722	207,269	77,789	102,465	64,100	64,100
Computer Software - CIS Conversion	D		173,079					
Computer Software - Financial, Billing, Network, Outage Management, Website Design, Telepone System, and General	D		37,224	77,921	46,674	66,207	131,900	216,545
Computer Software - Smart Meter Disposition (EB-2012-0272)	D					62,416		
Office Furniture and Equipment (1915)								
Office Equipment & Furniture - Chairs, Safe, Wall Shelves, furniture, meeting table, storage cabinets, etc.	D			4,925	17,332	4,711	5,000	5,000
Transportation Equipment (1930)								
Transportation Equipment - Bucket Truck	D		502,256	326,904	255,428	107,758	207,000	
Transportation Equipment - Pickup / Van	D		28,935			79,027	40,281	218,400
Transportation Equipment - Trailer	D		29,518	5,295	2,838			
Tools, Shop and Garage Equipment (1940)								
Tools, Shop, & Garage Equipment - Loggers, Testers, Locators, Generator, Dry Max Unit, Line Trackers, Pole Dolly, InfraRed Camera, Remote Control Flagmen, Tensioner machine, tools, etc.	D		97,132	90,319	58,717	87,199	35,685	67,250
Communications Equipment (1955)								
Communications Equipment - Cellular Remote Terminal Unit (O/H fault circuit indicators), Radio System	D		4,509	11,430	3,365			
Sub-Total		0	1,114,142	825,276	676,174	651,274	541,091	680,639
Miscellaneous								
Total		**0**	**4,188,948**	**3,256,768**	**4,927,692**	**9,155,578**	**5,501,009**	**5,978,919**
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets *(input as negative)*								
Total		**0**	**4,188,948**	**3,256,768**	**4,927,692**	**9,155,578**	**5,501,009**	**5,978,919**

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Table 24
Capital Project by Investment Category

Projects		2008	2009	2010	2011	2012	2013 Bridge Year	2014 Test Year
Reporting Basis			CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
System Access								
Renewable Energy Cost Cap Investments							4,000	153,000
Dunnville TS Breaker Position							29,000	442,000
Dunnville TS Make Ready Work								107,000
York Bridge Duct Installation - Engineering Design								20,000
Overhead / Underground Services			102,000	125,000	172,000	132,000	241,000	248,000
Betterments			362,000	444,000	235,000	435,000	803,000	451,000
Line Extensions			516,000	546,000	512,000	755,000	477,000	487,000
Meters				12,000	134,000	(12,000)	149,000	186,000
Meters - Smart Meter Disposition (EB-2012-0272)						3,682,000		
Contributed Capital - Regular			(164,000)	(230,000)	(179,000)	(198,000)	(190,000)	(190,000)
Contributed Capital - Developer Rebates			112,000	107,000	13,000	54,000	131,000	74,000
Sub-Total		-	928,000	1,004,000	887,000	4,848,000	1,644,000	1,978,000
System Renewal								
Pole Replacement Program			509,000	1,026,000	769,000	498,000	330,000	375,000
Eliminate Nanticoke Distribution Station (2008 Carryover)			1,000					
Eliminate Selkirk North 8kV Distribution Station			418,000					
Elimate Feeds from Lythmore Distribution Station (Ph.1-East)				184,000				
Sub-Total		-	928,000	1,210,000	769,000	498,000	330,000	375,000
System Service								
Conversion of Central Lane Phase II			153,000					
Moulton-Sherbrooke Townline-Rattlesnake Road Conversion, Dunnville			114,000					
Lakeshore Road Re-Build (Melville Lane Area)			315,000	1,000				
Construction of Line from Hagersville to Jarvis			300,000					
Construction of Line from Hagersville to Jarvis			215,000					
Purchase Hydro One F2 Feeder out of Argyle Distribution Station			124,000					
Install One Load Break Switch				24,000	2,000			
Conversion to Supply Innophos and Sherbrooke Area to 31M1 Feeder				137,000	322,000			
Alder Street, Dunnville - Conversion- Underground Rebuild				27,000	271,000	404,000	142,000	
Maple Street, Dunnville - Line Conversion to 27.6 kV					18,000	145,000		
Highway #3, Jarvis - Line Conversion from 8 kV to 27.6 kV					123,000	1,000		
27.6 kV Conversion into Cayuga					603,000	2,000		
Rebuild of Argyle Street, Caledonia (Sutherland St. to railway)					4,000	324,000	152,000	
27M5 Feeder Extension Caledonia (3-phase project)					1,274,000	1,698,000		
Main & Queen Streets, Dunnville - Road Re-construction						139,000		
Townsend Back-up Feeder						395,000	79,000	
Lakeshore Road Conversion - Haldimand Road 50 to Bookers Rd.						95,000	575,000	
Contributed Capital - Lakeshore Rd.Conversion (Grand Renewable Energy Park project)							(200,000)	
Conversion of Lakeshore Road (West of Kohler to 27.6 kV)								396,000
Conversion of Highway #54 to 27.6 kV							1,147,000	
Conversion to 27.6 kV, Stromness (Overloaded Step-down Trx.)							450,000	
Conversion to 27.6 kV Orkney, Inverness, Sutherland Streets, Caledonia							407,000	
Conversion to 27.6 kV - Kohler Road							234,000	
Partial Conversion of Step-down (SD-37) Transformer, Oneida								300,000
Caithness Street, Caledonia - Road Reconstruction								650,000
Conversion of York Village to 27.6 kV								300,000
Talbot Street, Cayuga - Road Reconstruction								500,000
Conversion of Step-down Transformer on Fisherville Road								800,000
Sub-Total		-	1,221,000	189,000	2,617,000	3,203,000	2,986,000	2,946,000
Spare Capital								
Transformers			(37,588)	19,904	(69,257)	(3,740)		
Meters			35,138	8,952	48,176	(40,893)		
Sub-Total		-	(2,450)	28,856	(21,081)	(44,633)	-	-
General Plant								
Transportation Equipment - Bucket Truck			502,256	326,904	255,428	107,758	207,000	
Transportation Equipment - Pickup / Van			28,935			79,027	40,281	218,400
Transportation Equipment - Trailer			29,518	5,295	2,838			
Building and Fixtures - Heat Trace Cabling, Storage/Pallet Racking, Floor Trenches, Overhead Garage Doors, Office Renovations, Lockers			6,414	32,033	138,090	22,502		
Computer Hardware - Workstations, Servers, Laptops, Ipads, etc.			43,352	69,180	75,941	67,895	57,125	109,344
Computer Hardware - Smart Meter Disposition (EB-2012-0272)						51,094		
Computer Software - ESRI Mapping System			191,722	207,269	77,789	102,465	64,100	64,100
Computer Software - CIS Conversion			173,079					
Computer Software - Financial, Billing, Network, Outage Management, Website Design, Telepone System, and General			37,224	77,921	46,674	66,207	131,900	216,545
Computer Software - Smart Meter Disposition (EB-2012-0272)						62,416		
Office Equipment & Furniture - Chairs, Safe, Wall Shelves, furniture, meeting table, storage cabinets, etc.				4,925	17,332	4,711	5,000	5,000
Tools, Shop, & Garage Equipment - Loggers, Testers, Locators, Generator, Dry Max Unit, Line Trackers, Pole Dolly, InfraRed Camera, Remote Control Flagmen, Tensioner machine, tools, etc.			97,132	90,319	58,717	87,199	35,685	67,250
Communications Equipment - Cellular Remote Terminal Unit (O/H fault circuit indicators), Radio System			4,509	11,430	3,365			
Sub-Total		-	1,114,142	825,276	676,174	651,274	541,091	680,639
Miscellaneous								
Total		0	4,188,692	3,257,132	4,928,093	9,155,641	5,501,091	5,979,639
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets *(input as negative)*								
Total		0	4,188,692	3,257,132	4,928,093	9,155,641	5,501,091	5,979,639

OVERVIEW OF DISTRIBUTION SYSTEM PLAN

HCHI filed a "draft" Distribution Asset Management Plan ("DAMP") as part of its 2010 COS rate application. Asset management is the skillful handling and control of physical infrastructure with a systematic methodology integrating best practices in all aspects of selection, design, construction, operating, maintenance, sustainment and retirement; in other words, the management of the asset through its entire life cycle. The goal is to strategically define how the assets are to be managed with the expectation to optimize the whole life business impact of costs, performance and risk exposures. Once the strategy is defined then the detailed processes used to manage the asset can be defined. As part of this Application, HCHI has updated its DAMP as previously filed utilizing the following key inputs and support processes:

- HCHI's – Distribution System Maintenance and Inspection Program (included as Appendix C in the DAMP)
- Distribution Asset Condition Assessment report prepared by Kinectrics Inc. (included as Appendix G in the DAMP)
- Discretionary Capital Projects Prioritization Model report prepared by Kinectrics Inc. (included as Appendix E in the DSP)
- Reliability Indices
- Other Reliability Information –Outage Causes and Components

HCHI has now developed a Distribution System Plan ("DSP") in accordance Chapter 5 of the Filing Requirements. The DAMP is included as Appendix H to the DSP.

HCHI describes expenditures on its distribution system and general plant over a five year planning period, including investment and asset-related maintenance expenditures

thereby developing a 5 year capital plan, pacing and prioritizing projects that will be reviewed internally on an annual basis.

HCHI addresses an integrated approach to planning, whereby investments for system service, renewal and expansion, renewable generation connections, smart grid development and implementation, and regionally planned infrastructure are planned and optimized together. HCHI's DSP considered planning in a regional context to help promote the cost effective development of electricity infrastructure in Ontario while also looking forward to smart grid development as it is expected to be integral to distribution system plans, keeping in mind any economies of scope.

APPENDIX A

Consolidated

DISTRIBUTION SYSTEM PLAN

- **Distribution System Plan**
- **Renewable Energy Generation Plan**
- **Distribution Asset Management Plan**
    - **Distribution System Maintenance and Inspection Program**
    - **Asset Condition Assessment**
- **Capital Expenditure Plans**
- **Distribution Loss Assessment**

(Refer to Separate Binder)

CAPITALIZATION POLICY

HCHI's Capitalization Policy is as follows:

1. Definition of an Asset

The CICA Handbook, at paragraph 1000.29, defines assets as economic resources controlled by an entity as a result of past transactions or events from which future economic benefits may be obtained. Assets have three essential characteristics:

1. They embody a future benefit that involves a capacity, singly or in combination with other assets, in the case of profit-oriented enterprises, to contribute directly or indirectly to future net cash flows and in the case of not-for-profit organizations, to provide services.

2. The entity can control access to the benefit.

3. The transaction or event giving rise to the entity's right to, or control of, the benefit has already incurred.

In addition, in identifying a benefit there must be:

A. An ability to earn income or supply a service.

B. A reasonable expectation that the benefit will be provided in future periods.

C. The future period must be identifiable and greater than one year.

The CICA Handbook specifically defines capital assets as identifiable assets comprising property, plant and equipment and intangible properties that meet all of the following criteria:

1. Are held for use in the production of supply of goods and services, for rental to others, for administrative purposes or for the development, construction, maintenance or repair to other capital assets.

2. Have been acquired, constructed or developed with the intention of being used on a continuing basis.

3. Are not intended for sale in the ordinary course of business.

In regard to whether to capitalize intangible property costs, the CICA Handbook states that a degree of certainty as to future benefits to be derived from costs attributed to developing intangible properties varies and in many cases, the expected future benefits may be too uncertain to justify asset recognition. However, when future benefits are reasonably assured, such costs should be capitalized (subject to materiality considerations) (CICA s 3062.07).

2. Capitalizing Upgrades and Improvements – "Betterments"

Betterment is defined as the cost incurred to enhance the service potential of a capital asset. Service potential may be enhanced:

- when there is an increase in the previously assessed physical output or service capacity,
- associated operating costs are lowered,
- the life or useful life is extended, or
- the quality of output is improved.

The definition of betterment is more difficult to apply to tangible capital assets that are complex networks of systems and are very long-lived, such as water systems because identifying expenditures that extend their lives may not be practicable.

For complex network systems the following distinctions can be used to identify maintenance and betterments:

1. Maintenance and repairs maintain the predetermined service potential of a tangible capital asset for a given useful life. Such expenditures are expenses in the period in which they are made.

    a. *A repair or replacement is comprised of the repair of an existing component, or the replacement of an existing component with a similar component.*

Betterments increase service potential (and may or may not increase the useful life of a tangible capital asset). Such expenditures would be included in the cost of the related asset.

3. Capitalization Threshold

Theoretically, any item that meets the definition and recognition criteria would be recorded as a tangible capital asset (TCA). In practical terms, departments shall treat any asset as a capital asset that in addition to the above conditions has a useful life in excess of one year and a per item cost greater than $500. This threshold may be changed at the discretion of Management and on an item-by-item basis if a department wishes to capitalize an amount lower than the amount prescribed above in order to ensure all material capital assets are included in the financial statements. Assets below the threshold are expensed in the period of purchase.

Land will always be capitalized, regardless of cost.

Characteristics to Consider

Repairs = Expense	Betterments = Capital Assets
All items – life less than 1 year	Life of more than 1 year
All items under $500	Items greater than $500
Replacement of individual components of a TCA due to age, "wear-and-tear" and damage in order to maintain the TCA in an operating condition without significantly enhancing functionality, capacity, usability and efficiency	Replacement of motor and parts that prolong the useful life
Renovations – carpeting, painting, etc.	The estimated life of the asset is extended by more than 25%
System and equipment repairs, in cases where the service potential of a building isn't enhanced, repairs – boilers, elevators, control system, etc.	The cost results in an increase in the capacity of the asset
Building repairs that are required in the normal maintenance process	The efficiency of the asset is increased by more than 10%
Repairs to restore assets damaged by fire, flood or similar events, to a condition just prior to the event	Significantly changes the character of the asset
	Reduction in operating cost

ACCOUNTING CHANGES UNDER CGAAP

On July 17, 2012, the Board issued a letter stating they will permit electricity distributors electing to remain on Canadian Generally Accepted Accounting Principles ("CGAAP") in 2013 to implement regulatory accounting changes for depreciation expense and capitalization policies effective January 1, 2013. HCHI has opted for the deferral of its adoption of International Financial Reporting Standards ("IFRS") until January 1, 2015, having elected to remain on CGAAP until that time, and has implemented the required regulatory accounting changes for depreciation expense and capitalization policies. HCHI's 2014 COS Application reflects that these changes were made. HCHI changed the estimated useful lives of its assets effective January 1, 2013. No changes were required in HCHI's capitalization of overheads.

These accounting changes under CGAAP have been implemented consistent with the Board's regulatory accounting policies as set out for modified IFRS as contained in the *Report of the Board, Transition to International Financial Reporting Standards*, EB-2008-0408, the Kinectrics Report and the Revised 2012 Accounting Procedures Handbook ("APH").

HCHI has followed the accounting treatment as published in the July 2012 APH Frequently Asked Questions. The accounting requirements and treatment HCHI is using in Account 1576, "Accounting Changes under CGAAP", to record the financial differences arising as a result of changes to depreciation is permitted by the Board under CGAAP.

The amount of the cumulative variance for the property, plant, and equipment ("PPE") change in estimated useful lives, in the amount of $(1,459,184), has been recorded in account 1576 along with the required rate of return of $(419,515). This results in a total amount of $(1,878,699) to be refunded to rate payers. Refer to Exhibit 9, Tab 4, Schedule 1 for disposition and rate rider calculations by customer class. HCHI has filed OEB Appendix 2-EE "Account 1576 (2013)" as part of this Application and included in Table 25 below.

Table 25
Account 1576 - Accounting Changes under CGAAP

	2010 Rebasing Year	2011	2012	2013	2014 Rebasing Year	2015	2016	2016	2017
Reporting Basis	CGAAP	IRM	IRM	IRM	CGAAP - ASPE	IRM	IRM	IRM	IRM
Forecast vs. Actual Used in Rebasing Year	Forecast	Actual	Actual	Forecast	Forecast				
				$	$	$	$	$	$
PP&E Values under former CGAAP									
Opening net PP&E - Note 1				41,894,496					
Net Additions - Note 4				3,834,438					
Net Depreciation (amounts should be negative) - Note 4				-2,433,897					
Closing net PP&E (1)				43,295,037					
PP&E Values under revised CGAAP (Starts from 2013)									
Opening net PP&E - Note 1				41,894,496					
Net Additions - Note 4				3,834,438					
Net Depreciation (amounts should be negative) - Note 4				-974,713					
Closing net PP&E (2)				44,754,221					
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP				-1,459,184					

Effect on Deferral and Variance Account Rate Riders			
Closing balance in Account 1576	-1,459,184	**WACC**	5.75%
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	- 419,515	**# of years of rate rider disposition period**	5
Amount included in Deferral and Variance Account Rate Rider Calculation	-1,878,699		

Notes:

1 For an applicant that made the capitalization and depreciation expense accounting policy changes on January 1, 2013, the PP&E values as of January 1, 2013 under both former CGAAP and revised CGAAP should be the same.

2 Return on rate base associated with Account 1576 balance is calculated as:

the variance account opening balance as of 2014 rebasing year x WACC X # of years of rate rider disposition period

* Please note that the calculation should be adjusted once WACC is updated and finalized in the rate application.

3 Account 1576 is cleared by including the total balance in the deferral and variance account rate rider calculation.

4 Net additions are additions net of disposals; Net depreciation is additions to depreciation net of disposals.

Capitalization of Overhead

On February 24, 2010, the Board issued guidance on the accounting for overhead costs associated with capital work. In this letter the Board specifically noted that it was requiring full compliance with IFRS requirements on capitalization of overheads which would result in a reduction in capitalized overhead for some electricity distributors that had previously capitalized administration and overhead costs.

HCHI reviewed its capitalization of overhead costs associated with its capital work and established that there were no capitalized general overhead costs. Therefore, HCHI has not made any accounting changes associated with the capitalization of overheads per the Board's July 17, 2012 letter.

HCHI has identified the burden rates related to the capitalization of costs of self-constructed assets in Table 26 below.

Table 26
Burden Rates – Capitalization of Costs

Overhead Type	2010 Board Approved	2010 Actual	2011 Actual	2012 Actual	2013 Bridge Year	2014 Test Year
Burden Rate						
Operations / Engineering Labour Rate	50%	50%	50%	50%	50%	50%
Material Rate	16%	16%	16%	16%	16%	16%
Vehicle Rates per Hour						
Bucket Trucks	$ 41.00	$41.00	$45.00	$45.00	$45.00	$45.00
Pickups / Vans	$ 20.00	$20.00	$20.00	$20.00	$20.00	$20.00

HCHI has not completed OEB Appendix 2-DB "Overhead" as it has not made any adjustments to its capitalization policy associated with overhead costs.

COSTS OF ELIGIBLE INVESTMENTS FOR CONNECTION OF QUALIFYING GENERATION FACILITIES

OVERVIEW OF ELIGIBLE INVESTMENTS

HCHI has included costs incurred in the 2013 Bridge Year and the 2014 Test Year as described in section 79.1 of the OEB Act and Regulation 330/09 under the OEB Act. OEB Appendix 2-FA "Proposed REG Investment", Appendix 2-FB "Calculation of REG Improvement" and Appendix 2-FC "Calculation of REG Expansion" have been completed and submitted as part of this Application.

HCHI's Renewable Energy Generation ("REG") Plan, included as Appendix C of the DSP, includes specific project details of the eligible REG investments. HCHI has included costs for capital expansion investments for the 2013 Bridge Year and the 2014 Test Year. Costs for capital enabling improvement projects have been included for the 2014 Test Year.

HCHI has performed the necessary calculations to record the direct benefit and resulting provincial recovery portions of each eligible investment, including the direct benefit portion at 17% of expansion projects and 6% of enabling improvement projects. The investments for 2013 and 2014 for the direct benefit portion have been included in the 2013 Bridge Year and the 2014 Test Year, respectively, as detailed in the REG Plan and the DSP. The provincial recovery portion of the investments for both 2013 and 2014 have been factored into the calculation of the 2014 Revenue Requirement calculation on OEB Appendix 2-FB "Calculation of REG Improvement" and Appendix 2-FC "Calculation of REG Expansion".

The Revenue Requirement calculations for the forecast years of 2015 to 2018 inclusive for both the direct benefit and provincial recovery portions have been completed as per OEB Appendices 2-FB and 2-FC. HCHI is proposing provincial recovery for the years 2013 through to and including 2018, and direct benefit recovery from its own customers for the years 2015 through to and including 2018 as a funding adder, with capital

investments to be recorded in OEB approved deferral accounts. The funding adder and request for a deferral account are discussed in more detail in Exhibit 9, Tab 5. HCHI has included Tables 27 and 28 below detailing the REG Plan investments.

Table 27
REG Investments – Enabling Improvements

REG Investment	2013	2014	2015	2016	2017	2018
SCADA System		246,000				
Total Enabling Improvement Investments	**-**	**246,000**	**-**	**-**	**-**	**-**
Direct Benefit - 6%	-	14,760	-	-	-	-
Provincial Recovery - 94%	-	231,240	-	-	-	-
	-	246,000	-	-	-	-

Table 28
REG Investments - Expansions

REG Investment	2013	2014	2015	2016	2017	2018
Cost Cap - 250 kW Renewable Generator	22,500					
Dunnville TS Breaker Position	25,500	377,500				
Cost Cap - Renewable Generator		900,000	900,000	900,000	900,000	900,000
Dunnville TS - Feeder Egress / Metering			260,000			
Total Expansion Investments	**48,000**	**1,277,500**	**1,160,000**	**900,000**	**900,000**	**900,000**
Direct Benefit - 17%	8,160	217,175	197,200	153,000	153,000	153,000
Provincial Recovery - 83%	39,840	1,060,325	962,800	747,000	747,000	747,000
	48,000	1,277,500	1,160,000	900,000	900,000	900,000

For purposes of the Revenue Requirement calculation detailed in Tab 6, Schedule 2 of this Exhibit, the capital investments in each year have incorporated the half-year rule.

CALCULATION OF FUNDING REQUEST – DIRECT BENEFIT & PROVINCIAL RECOVERY

Tables 29 and 30 below provide a summary of the calculated Revenue Requirement for the REG Enabling Improvement Investments and the REG Expansion Investments. Detailed calculations can be found in the OEB Appendices 2-FB "Calculation of REG Improvement" and 2-FC "Calculation of REG Expansion" filed as part of this Application.

Table 29
REG Enabling Improvement Investments – Revenue Requirement

	2014 Test Year		2015 Forecast Year		2016 Forecast Year		2017 Forecast Year		2018 Forecast Year	
	Direct Benefit	Provincial Recovery	Direct Benefit	Provincial Recovery	Direct Benefit	Provincial Recovery	Direct Benefit	Provincial Recovery	Direct Benefit	Provincial Recovery
	6%	94%	6%	94%	6%	94%	6%	94%	6%	94%
OM&A Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Depreciation Expenses	1,476	23,124	2,952	46,248	2,952	46,248	2,952	46,248	2,952	46,248
Total Distribution Expenses	$ 1,476	$ 23,124	$ 2,952	$ 46,248	$ 2,952	$ 46,248	$ 2,952	$ 46,248	$ 2,952	$ 46,248
Regulated Return On Capital	$ 501	$ 7,849	$ 891	$ 13,954	$ 668	$ 10,465	$ 445	$ 6,977	$ 223	$ 3,488
PILs	(802)	(12,569)	(828)	(12,977)	281	4,410	749	11,739	928	14,543
Revenue Requirement	**$ 1,175**	**$ 18,404**	**$ 3,015**	**$ 47,225**	**$ 3,901**	**$ 61,123**	**$ 4,146**	**$ 64,964**	**$ 4,103**	**$ 64,279**
Provincial Rate Protection		$ 18,404		$ 47,225		$ 61,123		$ 64,964		$ 64,279
Monthly Amount Requested from IESO		$ 1,534		$ 3,935		$ 5,094		$ 5,414		$ 5,357

Table 30
REG Expansion Investments – Revenue Requirement

	2014 Test Year		2015 Forecast Year		2016 Forecast Year		2017 Forecast Year		2018 Forecast Year	
	Direct Benefit	Provincial Recovery	Direct Benefit	Provincial Recovery	Direct Benefit	Provincial Recovery	Direct Benefit	Provincial Recovery	Direct Benefit	Provincial Recovery
	17%	83%	17%	83%	17%	83%	17%	83%	17%	83%
OM&A Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Depreciation Expenses	4,507	22,003	12,957	63,263	19,961	97,459	26,081	127,339	32,201	157,219
Total Distribution Expenses	$ 4,507	$ 22,003	$ 12,957	$ 63,263	$ 19,961	$ 97,459	$ 26,081	$127,339	$ 32,201	$157,219
Regulated Return On Capital	$ 8,328	$ 40,662	$ 23,605	$115,249	$ 35,571	$173,671	$ 45,375	$221,537	$ 54,718	$267,150
PILs	520	2,539	1,668	8,142	2,951	14,407	4,342	21,199	5,881	28,714
Revenue Requirement	**$ 13,355**	**$ 65,204**	**$ 38,230**	**$186,654**	**$ 58,483**	**$285,537**	**$ 75,798**	**$370,075**	**$ 92,800**	**$453,083**
Provincial Rate Protection		$ 65,204		$186,654		$285,537		$370,075		$453,083
Monthly Amount Requested from IESO		$ 5,434		$ 15,555		$ 23,795		$ 30,840		$ 37,757

ADDITION OF ICM ASSETS TO RATE BASE

ICM CAPITAL ASSET AMOUNTS

HCHI has not applied for approval of Incremental Capital Module ("ICM") Assets in the past and therefore has no such assets added to its rate base.

SERVICE QUALITY AND RELIABILITY PERFORMANCE

SERVICE QUALITY INDICATORS

OEB regulations require Local Distribution Companies ("LDC") to annually report service quality and reliability performance indicators, and HCHI relies upon these to monitor its operational performance. HCHI's core values, and more specifically the customer focus value "*to providing excellent services and solutions to its customers, both anticipating and responding to customer needs*", relates directly to ensure HCHI manages its reliability results.

HCHI follows the Board's *Reporting and Record Keeping Requirements Guideline* to report its service quality indicators ("SQI's"). HCHI annually reports SQIs to the Board that measure the following:

- Connection of New Services (Low Voltage and High Voltage)
- Appointment Scheduling
- Appointments Met
- Rescheduling a Missed Appointment
- Telephone Accessibility
- Telephone Call Abandon Rate
- Written Responses to Enquiries
- Emergency Responses (Urban and Rural)
- Reconnection Standards

Table 31 provides a summary of HCHI's SQI reporting for the years 2008 to 2012 inclusive. HCHI's performance measures over the 2008 to 2012 period exceed the Board's approved standards. Table 32 reports the Service Reliability Indices for the period 2008 to 2012 which are also filed as OEB Appendix 2-G "SQI" as part of this Application.

Table 31
Service Quality Indicators – 2008 to 2012

Service Quality Indicator	2008	2009	2010	2011	2012	OEB Standard
New Connections - Low Voltage	95.7%	96.7%	99.2%	97.0%	99.0%	90.0%
New Connections - High Voltage	N/A	100.0%	N/A	N/A	N/A	90.0%
Appointment Scheduling	N/A	98.8%	98.1%	99.1%	99.6%	90.0%
Appointments Met	98.2%	98.7%	98.3%	98.9%	99.7%	90.0%
Rescheduling a Missed Appointment	N/A	92.3%	98.0%	96.7%	100.0%	100.0%
Telephone Accessibility	88.6%	80.4%	88.8%	83.4%	85.5%	65.0%
Telephone Call Abandon Rate	N/A	3.3%	2.3%	3.1%	2.5%	10.0%
Written Responses to Enquiries	97.7%	95.0%	99.3%	98.4%	99.8%	80.0%
Emergency Responses - Urban	93.1%	100.0%	95.0%	87.5%	93.3%	80.0%
Emergency Responses - Rural	100.0%	93.8%	100.0%	96.6%	100.0%	80.0%
Reconnection Standards	N/A	N/A	N/A	100.0%	100.0%	85.0%

Table 32
Service Reliability Indices – 2008 to 2012

Service Reliabity Indices	Includes Loss of Supply					Excludes Loss of Supply				
	2008	2009	2010	2011	2012	2008	2009	2010	2011	2012
System Average Interruption Duration Index - **SAIDI**	7.101	4.322	2.995	8.528	2.828	7.033	4.006	2.772	8.338	2.223
System Average Interruption Frequency Index - **SAIFI**	2.628	1.586	1.750	3.891	1.664	2.584	1.392	1.198	3.301	1.169
5 Year Historical Average										
SAIDI					**5.155**					**4.874**
SAIFI					**2.304**					**1.929**

Exhibit 3 – Operating Revenue

	Tab	Schedule	Appendix
Overview	1		
Overview of Operating Revenue		1	
Summary of Operating Revenue Table		2	
Distribution Revenue	2		
Distribution Revenue and Variance Analysis		1	
Weather Normalized Load and Customer/ Connection Forecast		2	
Monthly Data Used for Regression Analysis			A
Monthly Heating & Cooling Degree Data Used in Analysis of Load Forecast Models			B
Other Operating Revenue	3		
Summary of Other Operating Revenue		1	
Variance Analysis on Other Operating Revenue		2	

OVERVIEW OF OPERATING REVENUE

Haldimand County Hydro Inc. ("HCHI") is proposing a total Service Revenue Requirement of $14,012,613 for the 2014 Test Year. This amount includes a Base Revenue Requirement of $12,874,552 plus revenue offsets of $1,138,061 to be recovered through Other Distribution Revenue.

Details of HCHI's Operating Revenue for 2010 Board Approved, 2010 Actual, 2011 Actual, 2012 Actual, the 2013 Bridge Year and the 2014 Test Year are presented in this Exhibit. This Exhibit also provides a variance analysis by rate class of the material changes in Operating Revenue components. Distribution revenue does not include revenue from commodity sales or other cost of power pass through costs.

HCHI's Distribution Revenue has been calculated using the appropriate Ontario Energy Board ("Board") Approved Tariff of Rates and Charges for the applicable year. Total Distribution Revenue includes Board Approved specific service charges, rent from electric property, late payment charges, interest and other miscellaneous revenues. Note that interest does not include any amount for Deferred Interest calculated on account of deferral and variance accounts.

A summary of Operating Revenues is presented in Table 1 of this Exhibit at Tab 1, Schedule 2. Year over year variances are shown in Table 5 and at Tab 2, Schedule 1, with the amounts exceeding the materiality threshold of $64,000 having been highlighted in the table. The variance analysis with individual explanations in distribution revenue follows these tables and the variance analysis of other distribution revenue appears in Tab 3, Schedule 2.

Distribution Revenue

Information related to HCHI's Distribution Revenue includes details such as weather normalized load forecasting methodology reflecting expected Conservation and

Demand Management ("CDM") results, weather normalized volume and forecast of customers based on the historical number of customers billed throughout the year and known economic conditions. Variance analysis on the distribution revenue is set out in Tables 4 through 8 at Tab 2, Schedule 1.

Note that Distribution Revenue in 2012 reflects HCHI's Smart Meter Cost Recovery application (EB-2012-0272) Decision issued by the Board on November 1, 2012. All funding adder revenues received since May 1, 2006 until expiry of the Smart Meter Funding Adder April 30, 2012, in the amount of $1,375,043, were transferred from the Smart Meter deferral sub-account 1555 to Distribution Revenue in 2012.

Other Revenue

Other Revenue includes such things as Late Payment Charges, Specific Service Charges, Standard Supply Service ("SSS") Administration Charge, Rent from Electric Property, Retail Service Revenues, Miscellaneous Service Revenues and Interest. A summary of these Operating Revenues is presented in Tables 37 and 38, at Tab 3, Schedule 1 with a materiality analysis of variances presented in Tab 3, Schedule 2.

SUMMARY OF OPERATING REVENUE

The following Table 1 summarizes HCHI's total base Distribution Revenue Requirement calculated on HCHI's weather normalized forecasts, other distribution revenue and total service revenue requirement. The revenue numbers for each of the actual years are from HCHI's audited financial statements which reconcile to the annual filings with the Board. The 2013 Bridge year Distribution Revenue is based on HCHI's Board Approved rates applied to HCHI's 2013 forecast for customer counts and weather normalized usage. The proposed 2014 Test year distribution revenue is calculated on HCHI's proposed 2014 distribution rates applied to the 2014 forecast of customer counts and weather normalized usage.

Table 1
Distribution Revenue Requirement ($)

Description	2010 Board Approved	2010 Actual Year	2011 Actual Year	2012 Actual Year	2013 Bridge Year	2014 Test Year "Proposed"
Distribution Revenues:						
Residential	8,461,082	8,466,776	8,558,988	9,847,173	9,819,694	8,892,831
General Service Less Than 50 kW	2,057,572	1,916,178	1,961,828	2,149,277	2,188,990	1,711,607
General Service 50 to 4,999 kW	1,664,038	1,807,747	1,721,631	1,690,867	1,762,650	1,430,483
Street Lighting	195,717	158,262	295,390	299,950	318,916	321,966
Sentinel Lighting	73,999	45,765	88,497	123,186	114,318	118,345
Unmetered Scattered Load	21,999	19,410	18,684	18,114	18,098	17,974
Embedded Distributor - Hydro One Networks	172,340	545,693	165,467	156,476	146,578	381,346
Total Base Distribution Revenue Requirement	12,646,747	12,959,831	12,810,485	14,285,043	14,369,244	12,874,552
% of Total Revenue	92%	91%	91%	92%	102%	92%
Other Revenue:						
Late Payment Charges	319,125	349,416	289,018	319,383	310,717	310,717
Specific Service Charges	133,200	136,247	109,529	122,565	120,859	120,987
Other Operating Revenue	183,821	178,438	182,515	161,717	176,842	172,104
Other Income and Deductions	452,998	581,002	627,319	703,830	(953,935)	534,253
Total Other Revenue	1,089,144	1,245,103	1,208,381	1,307,495	(345,517)	1,138,061
% of Total Revenue	8%	9%	9%	8%	(2%)	8%
Total Service Revenue Requirement	13,735,891	14,204,934	14,018,866	15,592,538	14,023,727	14,012,613
Variance from 2010 Board Approved		3.41%	2.06%	13.52%	2.10%	2.01%
Variance from Prior Year			(1.31%)	11.23%	(10.06%)	(0.08%)

Notes – Table 1 Information

1. The Standard Supply Service ("SSS") Administrative Charge revenue has been included in Other Revenue as it represents a revenue offset.

2. The revenue for the General Service 50 to 4,999 kW rate class is net of transformer allowance credits applicable to eligible customers in this rate class.

3. The Smart Meter Funding Adder ("SMFA"), Smart Meter Disposition Rate Rider ("SMDR"), and the Smart Meter Incremental Revenue Requirement Rate Rider ("SMIRR") have been included in the 2012 and 2013 Distribution Revenue for the applicable customer classes as detailed in Table 2 below.

Table 2
Smart Meter Funding Adders and Rate Riders
– Included in Distribution Revenue - 2012 & 2013

Customer Rate Class	SMFA	SMDR	SMIRR	Total
Residential	$ 1,210,674	$ 91,200	$ 130,756	$ 1,432,630
General Service Less Than 50 kW	$ 155,183	$ 18,628	$ 24,966	$ 198,777
General Service 50 to 4,999 kW (Non-Interval Metered)	$ 9,186	$ 457	$ 1,788	$ 11,431
Total 2012 Smart Meter Distribution Revenue	$ 1,375,043	$ 110,285	$ 157,510	$ 1,642,838
Residential		$ 542,004	$ 777,168	$ 1,319,172
General Service Less Than 50 kW		$ 110,544	$ 148,140	$ 258,684
General Service 50 to 4,999 kW (Non-Interval Metered)		$ 2,868	$ 11,232	$ 14,100
Total 2013 Smart Meter Distribution Revenue	$ -	$ 655,416	$ 936,540	$ 1,591,956

4. The Property, Plant, and Equipment ("PPE") adjustment, in the amount of $1,459,184, on account of HCHI's change in useful lives has been included as a reduction to Other Revenue in 2013 as part of the Other Income and Deductions line. This PPE adjustment has been recorded in Account 1576 "Accounting Changes under CGAAP" as detailed in Exhibit 9 Tab 4 Schedule 1. As noted in Exhibit 1, Tab 5, Schedule 16 and in Exhibit 2 at Tab 1 Schedule 1 HCHI has elected not to transition to IFRS until January 1, 2015 but has made the required regulatory accounting changes under Canadian Generally Accepted Accounting

Principles ("CGAAP") effective January 1, 2013 as mandated by the Board in its letter dated July 17, 2012.

Table 3 provides HCHI's total base Distribution Revenue Requirement excluding the Smart Meter Funding Adder and Rate Rider amounts detailed in Table 2 above. It also excludes the PPE Adjustment included in the 2013 Other Income and Deductions line as described in Note 4 to Table 1.

Table 3
Distribution Revenue Requirement ($)
(Excluding Smart Meter Amounts & PPE Adjustment)

Description	2010 Board Approved	2010 Actual Year	2011 Actual Year	2012 Actual Year	2013 Bridge Year	2014 Test Year "Proposed"
Distribution Revenues:						
Residential	8,461,082	8,466,776	8,558,988	8,414,543	8,500,522	8,892,831
General Service Less Than 50 kW	2,057,572	1,916,178	1,961,828	1,950,500	1,930,306	1,711,607
General Service 50 to 4,999 kW	1,664,038	1,807,747	1,721,631	1,679,436	1,748,550	1,430,483
Street Lighting	195,717	158,262	295,390	299,950	318,916	321,966
Sentinel Lighting	73,999	45,765	88,497	123,186	114,318	118,345
Unmetered Scattered Load	21,999	19,410	18,684	18,114	18,098	17,974
Embedded Distributor - Hydro One Networks	172,340	545,693	165,467	156,476	146,578	381,346
Total Base Distribution Revenue Requirement	12,646,747	12,959,831	12,810,485	12,642,205	12,777,288	12,874,552
% of Total Revenue	92%	91%	91%	91%	92%	92%
Other Revenue:						
Late Payment Charges	319,125	349,416	289,018	319,383	310,717	310,717
Specific Service Charges	133,200	136,247	109,529	122,565	120,859	120,987
Other Operating Revenue	183,821	178,438	182,515	161,717	176,842	172,104
Other Income and Deductions	452,998	581,002	627,319	703,830	505,249	534,253
Total Other Revenue	1,089,144	1,245,103	1,208,381	1,307,495	1,113,667	1,138,061
% of Total Revenue	8%	9%	9%	9%	8%	8%
Total Service Revenue Requirement	13,735,891	14,204,934	14,018,866	13,949,700	13,890,955	14,012,613
Variance from 2010 Board Approved		3.41%	2.06%	1.56%	1.13%	2.01%
Variance from Prior Year			(1.31%)	(0.49%)	(0.42%)	0.88%

The following Table 4 illustrates the Distribution Revenue calculated on the basis of HCHI's existing Board Approved May 1, 2013 rates as compared to the Distribution Revenue calculated using HCHI's proposed rates to be effective May 1, 2014.

Table 4
Distribution Revenue ($)
Existing Rates versus Proposed Rates

Rate Class	Test Year Load Forecast				Revenues at Current Rates			Revenues at Proposed Rates		
	Customers	Connections	kWh	kW	Revenues at Current Rates	Transformer Allowance Credit	Revenue Excluding Transformer Allowance	Class Specific Revenue Requirement	Transformer Allowance Credit	Revenue Excluding Transformer Allowance
Residential	18,772		169,003,519		$ 8,571,640		$ 8,571,640	$ 8,892,831		$ 8,892,831
General Service Less Than 50 kW	2,363		53,925,141		$ 1,928,924		$ 1,928,924	$ 1,711,607		$ 1,711,607
General Service 50 to 4,999 kW	153		121,879,907	342,324	$ 1,844,000	$ 92,302	$ 1,751,698	$ 1,522,785	$ 92,302	$ 1,430,483
Street Lighting		2,979	2,387,575	6,648	$ 321,316		$ 321,316	$ 321,966		$ 321,966
Sentinel Lighting		502	327,143	909	$ 108,730		$ 108,730	$ 118,345		$ 118,345
Unmetered Scattered Load		68	350,238		$ 17,943		$ 17,943	$ 17,974		$ 17,974
Embedded Distributor - Hydro One Networks Inc.	8		72,629,941	227,715	$ 147,037		$ 147,037	$ 381,346		$ 381,346
Total	24,845	24,845	420,503,464	577,596	$ 12,939,590	$ 92,302	**$ 12,847,288**	$ 12,966,854	$ 92,302	**$ 12,874,552**

This same information is detailed in Exhibit 8, Tab 3, Schedule 1.

DISTRIBUTION REVENUE AND VARIANCE ANALYSIS

HCHI's Distribution Revenue and variances for 2010, 2011, 2012, and 2013 has been calculated using HCHI's Board Approved distribution rates for 2010, 2011, 2012, and 2013, respectively, and the actual and projected billing quantities for the applicable years. The 2014 Test Year Distribution Revenue has been calculated using the proposed rates in this Cost of Service Rate Application as detailed in Exhibit 8 and the forecasted billing quantities discussed further in this Exhibit. Distribution Revenue does not include commodity-related revenue.

HCHI has provided an analysis of distribution revenues for 2010 Board Approved, 2010 Actual, 2011 Actual, 2012 Actual, 2013 Bridge Year, and 2014 Test Year in Table 5 and Table 6 below. The variances exceeding HCHI's materiality threshold of $64,000 have been highlighted. As discussed in previous Exhibits, the materiality threshold was calculated as set out in the OEB's *Chapter 2 Filing Requirements for Distribution Rate Applications*, updated July 17, 2013 (the "Filing Requirements"), in particular that:

> *".... 0.5% of distribution revenue requirement for a distributor with a distribution revenue requirement greater than $10 million and less than or equal to $200 million; ...."*

Consumption (kWh), demand (kW), and customer / connection numbers analysis is also provided in Tables 7 through 9, respectively, for 2010 Board Approved, 2010 Actual, 2011 Actual, 2012 Actual, 2013 Bridge Year, and 2014 Test Year. HCHI has also included historical actuals for consumption (kWh), demand (kW), and customer / connection numbers for the years 2003 through to 2012 at Tab 2, Schedule 2 of this Exhibit.

Table 5
Distribution Revenue with Variances

Description	2010 Board Approved	2010 Actual Year	Variance from Board Approved	2011 Actual Year	Variance from 2010 Actual	2012 Actual Year	Variance from 2011 Actual	2013 Bridge Year "Normalized"	Variance from 2012 Actual	2014 Test Year "Normalized"	Variance from 2013 Bridge
Distribution Revenues:											
Residential	8,461,082	8,466,776	5,694	8,558,988	92,212	9,847,173	1,288,185	9,819,694	(27,479)	8,892,831	(926,863)
General Service Less Than 50 kW	2,057,572	1,916,178	(141,394)	1,961,828	45,650	2,149,277	187,449	2,188,990	39,713	1,711,607	(477,383)
General Service 50 to 4,999 kW	1,664,038	1,807,747	143,709	1,721,631	(86,116)	1,690,867	(30,764)	1,762,650	71,783	1,430,483	(332,167)
Street Lighting	195,717	158,262	(37,455)	295,390	137,128	299,950	4,560	318,916	18,966	321,966	3,050
Sentinel Lighting	73,999	45,765	(28,234)	88,497	42,732	123,186	34,689	114,318	(8,868)	118,345	4,027
Unmetered Scattered Load	21,999	19,410	(2,589)	18,684	(726)	18,114	(570)	18,098	(16)	17,974	(124)
Total Base Distribution Revenue Requirement Excluding Embedded Distributor - Hydro One	12,474,407	12,414,138	(60,269)	12,645,018	230,880	14,128,567	1,483,549	14,222,666	94,099	12,493,206	(1,729,460)
Variance from 2010 Board Approved		-0.48%		1.37%		13.26%		14.01%		0.15%	
Variance from Prior Year				1.86%		11.73%		0.67%		(12.16%)	
Embedded Distributor - Hydro One Networks	172,340	545,693	373,353	165,467	(380,226)	156,476	(8,991)	146,578	(9,898)	381,346	234,768
Variance from 2010 Board Approved		216.64%		(3.99%)		(9.21%)		(14.95%)		121.28%	
Variance from Prior Year				(69.68%)		(5.43%)		(6.33%)		160.17%	
Total Base Distribution Revenue Requirement	12,646,747	12,959,831	313,084	12,810,485	(149,346)	14,285,043	1,474,558	14,369,244	84,201	12,874,552	(1,494,692)
Variance from 2010 Board Approved		2.48%		1.29%		12.95%		13.62%		1.80%	
Variance from Prior Year				(1.15%)		11.51%		0.59%		(10.40%)	

Notes – Table 5 Information

1. The revenue for the General Service 50 to 4,999 kW rate class is net of transformer allowance credits applicable to eligible customers in this rate class.
2. The Smart Meter Funding Adder ("SMFA"), Smart Meter Disposition Rate Rider ("SMDR"), and Smart Meter Incremental Revenue Requirement Rate Rider ("SMIRR") have been included in the 2012 and 2013 Distribution Revenue for the applicable customer classes as detailed in Table 2 above.

Table 6
Distribution Revenue with Variances
(Excluding Smart Meter Amounts)

Description	2010 Board Approved	2010 Actual Year	Variance from Board Approved	2011 Actual Year	Variance from 2010 Actual	2012 Actual Year	Variance from 2011 Actual	2013 Bridge Year "Normalized"	Variance from 2012 Actual	2014 Test Year "Normalized"	Variance from 2013 Bridge
Distribution Revenues:											
Residential	8,461,082	8,466,776	5,694	8,558,988	92,212	8,414,543	(144,445)	8,500,522	85,979	8,892,831	392,309
General Service Less Than 50 kW	2,057,572	1,916,178	(141,394)	1,961,828	45,650	1,950,500	(11,328)	1,930,306	(20,194)	1,711,607	(218,699)
General Service 50 to 4,999 kW	1,664,038	1,807,747	143,709	1,721,631	(86,116)	1,679,436	(42,195)	1,748,550	69,114	1,430,483	(318,067)
Street Lighting	195,717	158,262	(37,455)	295,390	137,128	299,950	4,560	318,916	18,966	321,966	3,050
Sentinel Lighting	73,999	45,765	(28,234)	88,497	42,732	123,186	34,689	114,318	(8,868)	118,345	4,027
Unmetered Scattered Load	21,999	19,410	(2,589)	18,684	(726)	18,114	(570)	18,098	(16)	17,974	(124)
Total Base Distribution Revenue Requirement Excluding Embedded Distributor - Hydro One	12,474,407	12,414,138	(60,269)	12,645,018	230,880	12,485,729	(159,289)	12,630,710	144,981	12,493,206	(137,504)
Variance from 2010 Board Approved		-0.48%		1.37%		0.09%		1.25%		0.15%	
Variance from Prior Year				1.86%		(1.26%)		1.16%		(1.09%)	
Embedded Distributor - Hydro One Networks	172,340	545,693	373,353	165,467	(380,226)	156,476	(8,991)	146,578	(9,898)	381,346	234,768
Variance from 2010 Board Approved		216.64%		(3.99%)		(9.21%)		(14.95%)		121.28%	
Variance from Prior Year				(69.68%)		(5.43%)		(6.33%)		160.17%	
Total Base Distribution Revenue Requirement	12,646,747	12,959,831	313,084	12,810,485	(149,346)	12,642,205	(168,280)	12,777,288	135,083	12,874,552	97,264
Variance from 2010 Board Approved		2.48%		1.29%		-0.04%		1.03%		1.80%	
Variance from Prior Year				(1.15%)		(1.31%)		1.07%		0.76%	

Note – Table 6 Information

1. The revenue for the General Service 50 to 4,999 kW rate class is net of transformer allowance credits applicable to eligible customers in this rate class.

Table 7
Consumption (kWh) by Rate Class Variance Analysis

Customer Rate Class	2010 Board Approved	2010 Actual Year	Variance from Board Approved	2011 Actual Year	Variance from 2010 Actual	2012 Actual Year	Variance from 2011 Actual	2013 Bridge Year "Normalized"	Variance from 2012 Actual	2014 Test Year "Normalized"	Variance from 2013 Bridge
	kWh	kWh	%	kWh	%	kWh	%	kWh	%	kWh	%
Residential	171,936,412	172,161,499	0.13%	171,241,285	(0.53%)	168,308,353	(1.71%)	168,535,596	0.14%	169,003,519	0.28%
General Service Less Than 50 kW	61,801,919	56,182,092	(9.09%)	55,878,781	(0.54%)	54,847,744	(1.85%)	54,527,982	(0.58%)	53,925,141	(1.11%)
General Service 50 to 4,999 kW	110,031,720	116,961,012	6.30%	119,765,784	2.40%	118,292,323	(1.23%)	122,050,807	3.18%	121,879,907	(0.14%)
Street Lighting	2,328,757	2,249,880	(3.39%)	2,273,663	1.06%	2,389,979	5.12%	2,387,575	(0.10%)	2,387,575	0.00%
Sentinel Lighting	418,928	401,194	(4.23%)	385,924	(3.81%)	361,875	(6.23%)	351,211	(2.95%)	327,143	(6.85%)
Unmetered Scattered Load	482,264	454,181	(5.82%)	406,515	(10.49%)	389,982	(4.07%)	363,058	(6.90%)	350,238	(3.53%)
Total Customer Consumption - kWh Excluding Embedded Distributor - Hydro One	347,000,000	348,409,858		349,951,952		344,590,256		348,216,229		347,873,523	
Variance from 2010 Board Approved		0.41%		0.85%		(0.69%)		0.35%		0.25%	
Variance from Prior Year				0.44%		(1.53%)		1.05%		(0.10%)	
Embedded Distributor - Hydro One Networks	83,184,875	73,870,537	(11.20%)	74,192,250	0.44%	71,831,928	(3.18%)	72,430,489	0.83%	72,629,941	0.28%
Variance from 2010 Board Approved		(11.20%)		(10.81%)		(13.65%)		(12.93%)		(12.69%)	
Variance from Prior Year				0.44%		(3.18%)		0.83%		0.28%	
Total Customer Consumption - kWh	430,184,875	422,280,395		424,144,202		416,422,184		420,646,718		420,503,464	
Variance from 2010 Board Approved		(1.84%)		(1.40%)		(3.20%)		(2.22%)		(2.25%)	
Variance from Prior Year				0.44%		(1.82%)		1.01%		(0.03%)	

Table 8
Consumption (kW) by Rate Class Variance Analysis

Customer Rate Class	2010 Board Approved	2010 Actual Year	Variance from Board Approved	2011 Actual Year	Variance from 2010 Actual	2012 Actual Year	Variance from 2011 Actual	2013 Bridge Year "Normalized"	Variance from 2012 Actual	2014 Test Year "Normalized"	Variance from 2013 Bridge
	kW	kW	%	kW	%	kW	%	kW	%	kW	%
General Service 50 to 4,999 kW	298,148	329,361	10.47%	336,851	2.27%	336,349	(0.15%)	342,804	1.92%	342,324	(0.14%)
Street Lighting	6,475	6,542	1.03%	6,601	0.90%	6,620	0.29%	6,648	0.42%	6,648	0.00%
Sentinel Lighting	1,167	1,110	(4.88%)	1,069	(3.69%)	1,003	(6.17%)	976	(2.69%)	909	(6.86%)
Total Customer Consumption - kW Excluding Embedded Distributor - Hydro One	305,790	337,013		344,521		343,972		350,428		349,881	
Variance from 2010 Board Approved		10.21%		12.67%		12.49%		14.60%		14.42%	
Variance from Prior Year				2.23%		(0.16%)		1.88%		(0.16%)	
Embedded Distributor - Hydro One Networks	276,949	241,211	(12.90%)	264,787	9.77%	343,972	29.91%	227,250	(33.93%)	227,715	0.20%
Variance from 2010 Board Approved		(12.90%)		(4.39%)		24.20%		(17.95%)		(17.78%)	
Variance from Prior Year				9.77%		29.91%		(33.93%)		0.20%	
Total Customer Consumption - kW	582,739	578,224		609,308		687,944		577,678		577,596	
Variance from 2010 Board Approved		(0.77%)		4.56%		18.05%		(0.87%)		(0.88%)	
Variance from Prior Year				5.38%		12.91%		(16.03%)		(0.01%)	

Table 9
Customer / Connection by Rate Class Variance Analysis

Customer Rate Class	2010 Board Approved	2010 Actual Year	Variance from Board Approved	2011 Actual Year	Variance from 2010 Actual	2012 Actual Year	Variance from 2011 Actual	2013 Bridge Year "Normalized"	Variance from 2012 Actual	2014 Test Year "Normalized"	Variance from 2013 Bridge
	kWh	kWh	%	kWh	%	kWh	%	kWh	%	kWh	%
Residential	18,534	18,465	(0.37%)	18,531	0.36%	18,617	0.46%	18,664	0.25%	18,772	0.58%
General Service Less Than 50 kW	2,357	2,363	0.25%	2,380	0.72%	2,344	(1.51%)	2,356	0.51%	2,363	0.30%
General Service 50 to 4,999 kW	143	143	0.00%	145	1.40%	150	3.45%	154	2.67%	153	(0.65%)
Street Lighting	2,879	3,015	4.72%	2,963	(1.72%)	2,982	0.64%	2,979	(0.10%)	2,979	0.00%
Sentinel Lighting	589	594	0.85%	567	(4.55%)	535	(5.64%)	529	(1.12%)	502	(5.10%)
Unmetered Scattered Load	84	78	(7.14%)	76	(2.56%)	73	(3.95%)	69	(5.48%)	68	(1.45%)
Total Customer Consumption - kWh Excluding Embedded Distributor - Hydro One	24,586	24,658		24,662		24,701		24,751		24,837	
Variance from 2010 Board Approved		0.29%		0.31%		0.47%		0.67%		1.02%	
Variance from Prior Year				0.02%		0.16%		0.20%		0.35%	
Embedded Distributor - Hydro One Networks	8	8	0.00%	8	0.00%	8	0.00%	8	0.00%	8	0.00%
Variance from 2010 Board Approved		0.00%		0.00%		0.00%		0.00%		0.00%	
Variance from Prior Year				0.00%		0.00%		0.00%		0.00%	
Total Customer Consumption - kWh	24,594	24,666		24,670		24,709		24,759		24,845	
Variance from 2010 Board Approved		0.29%		0.31%		0.47%		0.67%		1.02%	
Variance from Prior Year				0.02%		0.16%		0.20%		0.35%	

Distribution Revenue Variance Analysis

The variance analysis uses Tables 5, 6, 7, 8, and 9 for comparison purposes with the majority of the variance explained in two components – a volume variance (kWh, kW, and customer / connection numbers) and a price variance.

2010 Actual versus 2010 Board Approved:

The 2010 Actual base Distribution Revenue of $12,959,831 increased by 2.48% inclusive of the Embedded Distributor – Hydro One Networks Inc. ("HONI") rate class over the 2010 OEB-approved amount of $12,646,747.

The majority of this increase is on account of the General Service 50 to 4,999 kW rate class and the Embedded Distributor – HONI rate class offset by a decrease in the General Service Less Than 50 kW rate customer rate class.

The General Service Less Than 50 kW 2010 Actual consumption (kWh) was 9.09% lower than the forecast in the 2010 Board Approved amount. A combination of this decrease in load and only 8 months activity at the May 1, 2010 rates results in an overall decrease of $141,394 in distribution revenue for this class. The increase in the General Service 50 to 4,999 kW customer rate class is a result of the 2010 Actual kW consumption 10.47% higher than the forecasted load from the 2010 Board Approved kW a positive variance of $143,709. The largest contributor to the increase in Distribution Revenue from the 2010 Board Approved is the Embedded Distributor – HONI rate class at $373,353. The 2010 Actual kW was 12.90% lower than the approved forecasted kW but the variance can be explained by the difference in rates being charged to the Embedded Distributor for the first January through April 2010. Prior to May 1, 2010, HCHI did not have an approved rate class for the embedded distributor situation with HONI and was charging the most appropriate rate on its most current Tariff of Rate and Charges effective May 1, 2009; that is, the General Service 50 to 4,999 kW rate class. In conjunction with its 2010 COS rate application, HCHI applied for such a class and established a wheeling rate and monthly service charge for this

rate class based on HONI's forecasted load and direct allocation in the Board's Cost Allocation model. The May 1, 2009 rate for the General Service 50 to 4,999 kW rate class was $6.0333 / kW as compared to the 2010 Board Approved rate for the new Embedded Distributor rate class of $0.5594 / kW.

2011 Actual versus 2010 Actual:

HCHI's 2011 Actual decreased from the prior year (2010) by 1.15% or, $149,346. The largest contributors to this variance are the Residential, General Service 50 to 4,999 kW, Street Lighting, and Embedded Distributor – HONI rate classes.

The Residential customer rate class increase $92,212 is on account of the fixed / variable revenue ratio adjustment that was completed in conjunction with the 3rd Generation Incentive Regulation Mechanism ("IRM3") for rates effective May 1, 2011. In HCHI's 2010 COS rate application, and as agreed upon at settlement, the fixed / variable revenue ratio would change over the rate years commencing with the 2011 IRM3 resulting in a 47% fixed / 53% variable ratio in 2013. The following table outlines the staged changes.

Table 10
Fixed / Variable Revenue Ratio – Residential Rate Class

	2010	2011	2012	2013
Fixed	32.14%	37.00%	42.00%	47.00%
Variable	67.86%	63.00%	58.00%	53.00%

The $86,116 decrease in Distribution Revenue from the General Service 50 to 4,999 kW customer rate class and the $137,128 increase in Distribution Revenue from the Street Lighting rate class are also on account of an adjustment approved with HCHI's 2010 COS rate application. The revenue-to-cost ratios for the Street Lighting and Sentinel Lighting customer rate classes were below the bottom of the Board's target range of 70% for each of these two classes. In order to mitigate the rate increase with the 2010 COS rate application, these two customer rate classes were moved halfway

from their existing Revenue-to-Cost ratio effective with the May 1, 2010 approved rates and the remaining increase to the bottom target of 70% was completed in conjunction with the 2011 IRM3. The beneficiary of this move was the General Service 50 to 4,999 kW customer rate class, applying the additional revenue to the volumetric component of the rate only. Table 11 details the 2010 and 2011 Board Approved Revenue-to-Cost ratios for all customer rate classes.

Table 11
Revenue-to-Cost Ratios

Rate Class	2010	2011
Residential	99.86%	99.86%
General Service Less than 50 kW	101.78%	101.78%
General Service 50 to 4,999 kW	124.64%	112.88%
Sentinel Lighting	43.09%	70.00%
Street Lighting	46.20%	70.00%
Unmetered Scattered Load	80.81%	80.81%
Embedded Distributor - Hydro One	100.00%	100.00%

The remaining contributor to the decrease in Distribution Revenue in 2011 is on account of the Embedded Distributor rate class. The kW increased by 9.77% but the decreased Distribution Revenue is explained by the rates charged. As explained above, in the 2010 Actual versus 2010 Board Approved, the Distribution Revenue for 2010 Actual is comprised of four months at a much higher rate than the rate established for this "new" rate class, effective with the 2010 COS rate application, and therefore contributes to the decreased revenue in 2011.

2012 Actual versus 2011 Actual:

Distribution Revenue in 2012 increased by 11.51% or $1,474,558 as a result of Board Approval of HCHI's Smart Meter Cost Recovery application (EB-2012-0272). HCHI's Smart Meter costs were approved for disposition, effective November 1, 2012, including disposition of the Smart Meter Funding Adder ("SMFA") revenue that had been collected from all metered customers for the period May 1, 2006 to April 30, 2012.

HCHI transferred this SMFA revenue, in the amount of $1,375,043, from the 1555 deferral sub-account to Distribution Revenue as at November 1, 2012. Also, a Smart Meter Incremental Revenue Requirement rate rider ("SMIRR") and a Smart Meter Disposition rate rider ("SMDR") were approved effective November 1, 2012 to be charged and booked directly to Distribution Revenue. Details of the SMFA, SMIRR, and SMDR by customer rate class can be found in Table 2 above. After the smart meter amounts are removed, the variance is a 1.31% decrease, or $168,280, as shown in Table 6.

The majority of this decrease, $144,445, is from the Residential rate. This is a result of the consumption (kWh) decrease of 1.71% in 2012 and the volumetric rate decrease due to the second increment of the fixed / variable revenue ratio adjustment detailed in Table 10 above.

2013 Bridge Year versus 2012 Actual:

Similar to the 2012 Distribution Revenue, the 2013 Bridge Year includes smart meter amounts from the collection of the SMIRR and SMDR as detailed by customer rate class in Table 2. The Distribution Revenue increase in 2013, with the inclusion of the smart meter amounts, is 0.59% or $84,201, and the increase without the smart meter amounts is 1.07% or $135,083. When evaluating the variance with the SMIRR and SMDR amounts included, the main contributor to the increase is on account of the General Service 50 to 4,999 kW customer rate class. When excluding this revenue, the two rate classes contributing to the increase are the General Service 50 to 4,999 kW customer rate class and the Residential customer rate class.

The General Service 50 to 4,999 kW customer rate class variance in both revenue situations is on account of the 1.92% increase in the kW billing determinant and the increase in the Distribution Volumetric rate for rates effective May 1, 2013. The variance in the Residential customer rate class is on account of the increase in customer numbers and the final adjustment to the fixed / variable revenue ratio for the Residential customer rate class detailed in Table 10 above.

2014 Test Year versus 2013 Bridge Year:

Total 2013 base Distribution Revenue has decreased 10.40% or $1,494,692. This decrease is the net impact of the additional SMIRR and SMDR amounts of $1,591,596, included in the 2013 Bridge Year and the increase of $234,768 in the Embedded Distributor - HONI rate class. The Embedded Distributor - HONI rate class has been under contributing for a number of years which is supported by the Revenue- to-Cost ratio derived from the current Cost Allocation Model detailed in Exhibit 7 Cost Allocation.

Removing the SMDR and SMIRR amounts generates an increase in revenue of 0.76% or $97,264 This is the net effect of increased revenue from the Residential and Embedded Distributor - HONI rate classes and decreased revenue from the General Service Less Than 50 kW and General Service 50 to 4,999 kW customer rate classes. The increases for the Residential and Embedded Distributor – HONI rate classes are on account of increased consumption, kWh and kW respectively, and an increase being proposed for 2014 distribution rates. The decrease in the two General Service customer rate classes is a combination of the decrease in consumption, kWh and kW respectively, and the decrease in proposed 2014 distribution rates. The current Revenue-to-Cost ratios for these two customer rate classes show an over contribution which is also detailed in Exhibit 7 Cost Allocation. Revenues from the Sentinel Lighting rate class and the Embedded Distributor - HONI rate class, as mentioned above, are currently under contributing to their costs. In moving these two rate classes to appropriate Revenue-to-Cost ratios, the two General Service customer rate classes become the beneficiaries, effectively by lowering their respective Revenue-to-Cost ratios which results in lower distribution rates.

WEATHER NORMALIZED LOAD AND CUSTOMER/CONNECTION FORECAST

OVERVIEW

HCHI has calculated its load, customer/connection, and revenue forecasts with a load forecasting model that uses multivariate regressions in accordance with the Filing Requirements. This is a similar model to that used in HCHI's 2010 COS rate application and by a number of other distributors in previous cost of service rate applications.

The total system weather normalized purchased energy forecast is developed based on a multifactor regression that incorporates monthly historical purchased load, weather variables (such as heating and cooling degree days), days in the month, historical Conservation and Demand Management ("CDM") savings, and other variables (such as monthly full-time employment for the Hamilton-Niagara Peninsula Region and season flags), which are all discussed in further detail later on in this Exhibit. The resultant level of weather normalized purchases for the 2013 Bridge Year and the 2014 Test Year are then converted to a billed kWh by customer rate class. A further adjustment for forecasted CDM savings in the 2013 Bridge Year and the 2014 Test Year is completed to derive consumption by customer rate class. A detailed explanation of the load forecast methodology and process is provided later in this Exhibit.

During the review of 2010 COS rate applications, Board staff and Intervenors expressed concern that the regression analysis assigned coefficients to some variables that were counter intuitive and/or that some variables were not statistically significant. Specifically, in HCHI's 2010 COS rate application, its original load forecast model produced negative coefficients for the population variable and the Ontario GDP variable. HCHI has addressed these concerns in the load forecast used in this Application. HCHI's view on the overall process of load forecasting is that conducting a regression analysis on historical purchases to produce an equation that will predict purchases is appropriate. Based on the Board's approval of the current methodology in a number of previous COS rate applications, and based on the discussion that follows, HCHI

submits that its load forecasting methodology incorporated into this Application is reasonable at this time.

Table 12 shows the actual and forecasted trends for consumption (kWh), demand (kW) and customer / connection numbers.

Table 12
Summary of Load and Customer / Connection Forecast

	2010 Board Approved	2010 Actual	2011 Actual	2012 Actual	2013 Weather Normalized Bridge	2014 Weather Normalized Test
Actual and Predicted Purchases (kWh)						
Actual kWh Purchases		371,940,959	374,153,149	368,113,990		
Predicted kWh Purchases		365,011,314	375,417,407	373,779,761	372,558,390	373,636,010
% Difference of Actual and Predicted Purchases		-1.9%	0.3%	1.5%		
Predicted kWh Purchases After CDM Adjustment					371,298,850	370,933,411
Billing Determinants by Class						
Residential						
Customers	18,534	18,465	18,531	18,617	18,664	18,772
kWh	171,936,412	172,161,499	171,241,285	168,308,353	168,535,596	169,003,519
General Service Less Than 50 kW						
Customers	2,357	2,363	2,380	2,344	2,356	2,363
kWh	61,801,919	56,182,092	55,878,781	54,847,744	54,527,982	53,925,141
General Service 50 to 4,999 kW						
Customers	143	143	145	150	154	153
kWh	110,031,720	116,961,012	119,765,784	118,292,323	122,050,807	121,879,907
kW	298,148	329,361	336,851	336,349	342,804	342,324
Street Lighting						
Connections	2,879	3,015	2,963	2,982	2,979	2,979
kWh	2,328,757	2,249,880	2,273,663	2,389,979	2,387,575	2,387,575
kW	6,475	6,542	6,601	6,620	6,648	6,648
Sentinel Lighting						
Connections	589	594	567	535	529	502
kWh	418,928	401,194	385,924	361,875	351,211	327,143
kW	1,167	1,110	1,069	1,003	976	909
Unmetered Scattered Loads						
Connections	84	78	76	73	69	68
kWh	482,264	454,181	406,515	389,982	363,058	350,238
Load Forecast Excluding Embedded Distributor - Hydro One Networks						
Customer/Connections	24,586	24,658	24,662	24,701	24,751	24,837
kWh	347,000,000	348,409,858	349,951,952	344,590,256	348,216,229	347,873,523
kW from applicable classes	305,790	337,013	344,521	343,972	350,428	349,881
Embedded Distributor - Hydro One Networks Inc.						
Customers	8	8	8	8	8	8
kWh	83,184,875	73,870,537	74,192,250	71,831,928	72,430,489	72,629,941
kW	276,949	241,211	264,787	245,804	227,250	227,715
Total Load Forecast						
Customer/Connections	24,594	24,666	24,670	24,709	24,759	24,845
kWh	430,184,875	422,280,395	424,144,202	416,422,184	420,646,718	420,503,464
kW from applicable classes	582,739	578,224	609,308	589,776	577,678	577,596
Note: Hydro One Networks Inc. provided load forecast information (kWh & kW) for both 2013 and 2014						

Tables 13, 14, and 15 provide further supporting material for HCHI's weather normalized load forecast used in this Application. Customer and connection counts are shown as year-end numbers with the Sentinel Lighting, Street Lighting, and Unmetered Scattered Load customer rate classes reporting number of connections. Weather actual data is provided for 2003 through to, and including, 2012, with the 2013 Bridge Year and the 2014 Test Year reported as weather normalized. HCHI does not have a process to accurately adjust weather actual data to a weather normal basis. However, based on the information outlined in this Exhibit, a process to forecast energy on a weather normalized basis has been developed and used in this Application.

Table 13
Billed Energy and Customer / Connection Counts
(Excluding Embedded Distributor Rate Class)

Year	Billed (GWh)	Growth (GWh)	Percent Change	Customer/ Connection Count	Growth	Percent Change
2010 Board Approved	347.0			24,586		
2003 Actual	358.6			23,682		
2004 Actual	362.3	3.7	1.0%	23,816	134	0.6%
2005 Actual	373.4	11.1	3.1%	23,930	114	0.5%
2006 Actual	359.3	(14.1)	(3.8%)	24,033	103	0.4%
2007 Actual	360.3	1.0	0.3%	24,160	127	0.5%
2008 Actual	352.1	(8.3)	(2.3%)	24,343	183	0.8%
2009 Actual	338.5	(13.6)	(3.9%)	24,439	96	0.4%
2010 Actual	348.4	9.9	2.9%	24,658	219	0.9%
2011 Actual	350.0	1.5	0.4%	24,662	4	0.0%
2012 Actual	344.6	(5.4)	(1.5%)	24,701	39	0.2%
2013 Bridge	**348.2**	**3.6**	**1.1%**	**24,751**	**50**	**0.2%**
2014 Test	**347.9**	**(0.3)**	**(0.1%)**	**24,837**	**86**	**0.4%**

The following Tables 14 and 15 include the weather normalized load data for the Embedded Distributor – HONI.

Table 14
Billed Energy and Customer / Connection Counts by Customer Class
(Including Embedded Distributor Rate Class)

Year	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Embedded Distributor - HONI	Street Lighting	Sentinel Lighting	Unmetered Scattered Load	Total
Billed Energy (GWh)								
2010 Board Approved	172.0	61.8	110.0	83.2	2.3	0.4	0.5	430.2
2003 Actual	175.0	58.6	121.6	0.0	2.2	0.6	0.5	358.6
2004 Actual	172.2	56.3	130.4	0.0	2.2	0.6	0.5	362.3
2005 Actual	181.5	58.5	130.2	0.0	2.2	0.5	0.5	373.4
2006 Actual	171.5	56.7	127.8	0.0	2.2	0.5	0.5	359.3
2007 Actual	173.8	57.9	125.4	0.0	2.3	0.5	0.5	360.3
2008 Actual	171.8	57.8	119.2	0.0	2.3	0.5	0.5	352.1
2009 Actual	168.2	56.1	110.9	56.0	2.3	0.5	0.5	394.6
2010 Actual	172.2	56.2	117.0	73.9	2.2	0.4	0.5	422.3
2011 Actual	171.2	55.9	119.8	74.2	2.3	0.4	0.4	424.1
2012 Actual	168.3	54.8	118.3	71.8	2.4	0.4	0.4	416.4
2013 Bridge	**168.5**	**54.5**	**122.1**	**72.4**	**2.4**	**0.4**	**0.4**	**420.6**
2014 Test	**169.0**	**53.9**	**121.9**	**72.6**	**2.4**	**0.3**	**0.4**	**420.5**
Number of Customers/Connections								
2010 Board Approved	18,534	2,357	143	8	2,879	589	84	24,594
2003 Actual	17,585	2,282	157	0	2,713	857	88	23,682
2004 Actual	17,776	2,296	157	0	2,777	729	81	23,816
2005 Actual	17,893	2,324	157	0	2,764	705	87	23,930
2006 Actual	18,026	2,311	157	0	2,758	693	88	24,033
2007 Actual	18,139	2,335	143	0	2,794	665	84	24,160
2008 Actual	18,245	2,343	145	0	2,879	647	84	24,343
2009 Actual	18,309	2,374	144	8	2,872	656	84	24,447
2010 Actual	18,465	2,363	143	8	3,015	594	78	24,666
2011 Actual	18,531	2,380	145	8	2,963	567	76	24,670
2012 Actual	18,617	2,344	150	8	2,982	535	73	24,709
2013 Bridge	**18,664**	**2,356**	**154**	**8**	**2,979**	**529**	**69**	**24,759**
2014 Test	**18,772**	**2,363**	**153**	**8**	**2,979**	**502**	**68**	**24,845**

The actual data for the 2009 year on account of the Embedded Distributor – HONI is only a partial year. As detailed in HCHI's 2010 COS rate application, 7 of HONI's 8 supply points became embedded to HCHI on March 8, 2009 with the last point, Air Products, becoming embedded on April 24, 2009.

Table 15
Billed Energy and Customer / Connection Counts by Customer Class

Year	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Embedded Distributor - HONI	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
Energy Usage per Customer/Connection (kWh per customer/connection)							
2010 Board Approved	9,280	26,220	769,231	10,400,000	799	679	5,952
2003 Actual	9,953	25,686	774,580	0	819	686	6,125
2004 Actual	9,690	24,538	830,799	0	789	785	6,758
2005 Actual	10,142	25,185	829,339	0	788	766	5,907
2006 Actual	9,516	24,544	813,976	0	809	745	5,769
2007 Actual	9,581	24,789	876,724	0	822	737	5,944
2008 Actual	9,415	24,682	821,976	0	809	735	5,741
2009 Actual	9,188	23,633	770,390	7,005,604	803	713	5,732
2010 Actual	9,324	23,776	817,909	9,233,817	746	675	5,823
2011 Actual	9,241	23,478	825,971	9,274,031	767	681	5,349
2012 Actual	9,041	23,399	788,615	8,978,991	801	676	5,342
2013 Bridge	**9,030**	**23,144**	**792,538**	**9,053,811**	**801**	**664**	**5,262**
2014 Test	**9,003**	**22,820**	**795,449**	**9,078,743**	**801**	**652**	**5,182**
Annual Growth Rate in Usage per Customer/Connection							
2010 Board Approved	(0.5%)	10.3%	(6.0%)	12.6%	7.1%	0.5%	2.2%
2003 Actual							
2004 Actual	(2.6%)	(4.5%)	7.3%		(3.6%)	14.5%	10.3%
2005 Actual	4.7%	2.6%	(0.2%)		(0.2%)	(2.5%)	(12.6%)
2006 Actual	(6.2%)	(2.5%)	(1.9%)		2.7%	(2.6%)	(2.3%)
2007 Actual	0.7%	1.0%	7.7%		1.6%	(1.2%)	3.0%
2008 Actual	(1.7%)	(0.4%)	(6.2%)		(1.6%)	(0.2%)	(3.4%)
2009 Actual	(2.4%)	(4.3%)	(6.3%)		(0.7%)	(3.0%)	(0.2%)
2010 Actual	1.5%	0.6%	6.2%	31.8%	(7.1%)	(5.3%)	1.6%
2011 Actual	(0.9%)	(1.3%)	1.0%	0.4%	2.8%	0.8%	(8.1%)
2012 Actual	(2.2%)	(0.3%)	(4.5%)	(3.2%)	4.4%	(0.6%)	(0.1%)
2013 Bridge	**(0.1%)**	**(1.1%)**	**0.5%**	**0.8%**	**0.0%**	**(1.8%)**	**(1.5%)**
2014 Test	**(0.3%)**	**(1.4%)**	**0.4%**	**0.3%**	**0.0%**	**(1.8%)**	**(1.5%)**

As noted above under Table 14, the 2009 actual data for the Embedded Distributor – HONI rate class only existed for a partial year.

LOAD FORECAST AND METHODOLOGY

HCHI developed a weather normalized load forecast for all its customer rate classes excluding the Embedded Distributor - HONI rate. HONI supplied HCHI with an existing load forecast that has been previously used by HONI for their own purposes, including kWh and kW for all embedded points for the 2013 Bridge Year and the 2014 Test Year. Details of the HONI-provided weather normalized load forecast are included in Table 34 of this Exhibit.

For the balance of its customer rate classes, HCHI used a multifactor regression model that produces a system weather normalized purchased energy forecast. The model incorporates HCHI's historical data for the exact amount of kWh purchased from the IESO and embedded generators on a wholesale basis, and factors in other related monthly explanatory variables, such as heating and cooling degree days which occur in the same month, number of days in the month, full-time employment data for the Hamilton-Niagara Peninsula Region, and CDM activity. The results of the regression analysis produce an equation that predicts the monthly purchases based on those explanatory variables used in the regression analysis. The weather normalized purchased energy forecast is then adjusted by HCHI's "proposed" total loss factor – refer to Appendix 2-R "Loss Factors" calculations and details described in Exhibit 8, Tab 1, Schedule 4 - to produce a weather normalized billed energy forecast. Finally, the forecast of billed energy by rate class is developed based on a forecast of customer/connection numbers and historical usage patterns per customer/connection.

For the rate classes that have weather sensitive load, their forecasted billed energy is adjusted to ensure that the total billed energy forecast by rate class is equivalent to the total weather normalized billed energy forecast that has been determined from the regression model. In addition, the billed energy for the Residential, General Service Less Than 50 kW, and General Service 50 to 4,999 kW customer rate classes is further adjusted in the 2013 Bridge Year and 2014 Test Year to include the effect of the four

year CDM targets (2011 to 2014) assigned to HCHI as a condition of its electricity distributor's licence.

The forecast of customers / connections by rate class is determined using a geometric mean analysis of the historical data, except for a separate analysis of the growth in one specific customer rate class, Street Lighting. For the 2013 Bridge Year, the connections in this class have been forecast not to change from the value as at July 31, 2013. HCHI does not foresee any additional connections or loss of connections from the Street Lighting customer rate class in the 2014 Test Year. The geometric analysis of the Residential customer rate class only captured historical data for the period to period changes from 2004 to 2012. The growth rate from 2003 to 2004 is uncharacteristic of the activity in the Residential class as compared to the balance of the actual period data growth from 2004 to 2012. The results of the geometric analysis were not used to forecast the 2013 customer / connection forecast. The 2013 Bridge Year customer / connection forecast is the actual customer / connection numbers for each of the customer rate classes as at July 31, 2013. The 2014 Test Year customer forecast was then determined using the results of the geometric analysis applied to the 2013 Bridge Year customer numbers.

For those customer rate classes that use kW for the distribution volumetric billing determinant, an adjustment factor is applied to class energy (kWh) forecast based on the historical relationship between kW and kWh.

Manual adjustments have been made to the customer numbers in the Residential, General Service Less Than 50 kW and General Service 50 to 4,999 kW customer rate classes for services removed in each of the 2011 and 2012 actual years. Adjustments have also been completed for customer numbers, kWh, and kW for reclassification of customers in 2012 between the two General Service classes based on their average demand usage. All historical actual data, 2003 to 2012, was adjusted in the load forecast model for each customer's reclassification in order to accurately predict the 2013 and 2014 kWh, kW, and customer count for each rate class. The last manual

adjustment completed to the load forecast model was to the Unmetered Scattered Load customer rate class on account of a billing adjustment completed in August 2013 that affected the number of connections, kWh and kW. HCHI also completed a manual adjustment for CDM activity which is discussed in further detail at pages 20 to 26 of this Tab 2, Schedule 2.

The following will explain the forecasting process in more detail.

Purchased KWh Load Forecast

The forecast of total system purchased energy is developed using a multifactor regression model with the following independent variables: weather (i.e. heating and cooling degree days), employment for the Hamilton-Niagara Peninsula area, CDM activity, and calendar variables (i.e. days in month and seasonal flags). The regression model uses monthly kWh and monthly values of independent variables from January 2003 to December 2012 to determine a prediction formula with coefficients for each independent variable. This provides 120 monthly data points which represent a reasonable data set for use in a regression analysis. Once the predicted purchases are determined based on actual weather, the 2012 data is weather normalized using an average of the ten years (i.e. 2003 to 2012) heating and cooling degree days to produce weather-normalized predicted purchases for January to December 2014.

The specific independent variables used in the regression model were selected by means of a backward step regression analysis. Using an Excel-based program, a broad set of variables was originally included in the initial regression run of the program. The statistical results from the initial regression run were reviewed to identify assigned coefficients that were counter intuitive or not statistically significant. These variables were removed one at time with the regression re-run with the remaining variables each time until the regression statistics showed all of the remaining variables to be significant and intuitive. Variables in the initial run that were considered but rejected in this step-

by-step process included: population, customer numbers, Ontario Real GDP, number of peak hours, and unemployment in the Hamilton-Niagara Peninsula area.

Consistent with the approach used in other COS rate applications; it is HCHI's view that it is appropriate to review the impact of weather since 2003 on the energy usage, and then determine the average weather conditions from 2003 to 2012, which is then applied in the prediction formula to determine a weather normalized forecast. However, in accordance with the Board's Filing Requirements, HCHI has also provided a sensitivity analysis showing the impact on the 2014 forecast of purchases assuming weather normalized conditions are based on a 20-year trend of weather data. Refer to Tables 18 and 19 below. The 10-year average is already provided for in HCHI's regression model since the average weather conditions used are for the 10-year period of 2003 to 2012.

Weather impacts on load are apparent in both the winter heating season, and in the summer cooling season. For that reason, both heating degree days, a measure of coldness in winter, and cooling degree days, a measure of summer heat, are modeled.

The remaining factors determining energy use in the monthly model can be classified as calendar variables and load characteristics. For example, the number of days in a particular month will impact energy use. The modeling of purchased energy uses number of days in the month and "flag" variables to capture the typically lower usage in the spring and fall months and the higher usage in the summer months, as apparent in HCHI's historical usage.

The following Table 16 provides the resulting coefficients to be applied against each of the respective variables in the model to predict weather normalized purchases for 2013 and 2014:

Table 16
Monthly Predicted kWh Purchases Formula

=	Heating Degree Days	*	11,430
+	Cooling Degree Days	*	69,221
+	Number of Days in Month	*	1,077,980
+	Spring / Fall Flag	*	(2,309,984)
+	CDM Activity	*	(3)
+	Summer Months Flag	*	(1,808,822)
+	Employment Hamilton-Niagara Peninsula	*	47,704
+	Intercept of		(36,949,217)

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years are provided in Appendix A.

The sources of data for the various data points are:

a) Environment Canada website for monthly heating degree day ("HDD") and cooling degree day ("CDD") information. The base number from which both the HDD and the CDD are measured is 18 degrees Celsius. Hamilton Airport weather station data was used as this is the closest weather station to Haldimand County;

b) The monthly employment data was sourced from Statistics Canada Table 282-0062 for the Hamilton-Niagara Peninsula area.

c) The calendar provided information related to number of days in the month, the spring/fall flag, and the summer months flag; and

d) The CDM activity variable is an estimated level of monthly activity in CDM. For each year the monthly values grow at a constant value over the year. For the years 2006 to 2010, the addition of the monthly CDM activity values shown in Appendix A will equal the Net Energy Savings from the OPA 2006-2010 Final CDM Results for HCHI for each year from 2006 to 2010. These values reflect

the net energy savings from 2006 to 2010 programs and how these programs have persistent savings from 2007 to 2010.

For the years 2011 to 2014, the persistent Net Energy Savings from the Ontario Power Authority ("OPA") 2006-2010 Final CDM Results are supplemented by final results from the 2011 programs that contribute to the four year CDM target of 13,300,000 kWh assigned to HCHI, as a condition of its electricity distribution licence. Similarly, for the years 2012 to 2014, these results are further supplemented by the final results of the 2012 programs. The 2011 final actual results and the 2012 final actual results are based on the CDM Reports provided to HCHI by the OPA. The 2011 and the 2012 results have been included in the CDM activity variable since these results have impacted the actual 2012 power purchased. The OPA CDM 2006-2010 Final results, 2011 Final results, and 2012 Final results are filed in Exhibit 9 as Appendix D, E, and F respectively.

Table 16 outlines the CDM adjustments made to net energy savings for the years 2006 to 2014 based on the impact of the 2006 to 2012 programs and all programs persistence impacts into 2014. For the 2014 Test Year, the monthly values for the CDM activity variable will total 8,664,844 kWh represented by the persistence of programs into 2014 including 6,135,000 kWh from the OPA 2006-2010 final results, 1,520,730 kWh from the OPA 2011 final results and 1,009,114 kWh from the OPA 2012 final results. The impact of the 2013 and 2014 CDM programs has not been included in the CDM activity variable since they do not impact the actual purchases used in the regression analysis. A discussion on how the load forecast is adjusted for 2013 and 2014 programs and how the Lost Revenue Adjustment Mechanism ("LRAM") variance account values are determined by rate class is provided later in this Exhibit.

Table 17
OPA CDM Programs Final Results for 2006 - 2012
Net Energy Savings (kWh)

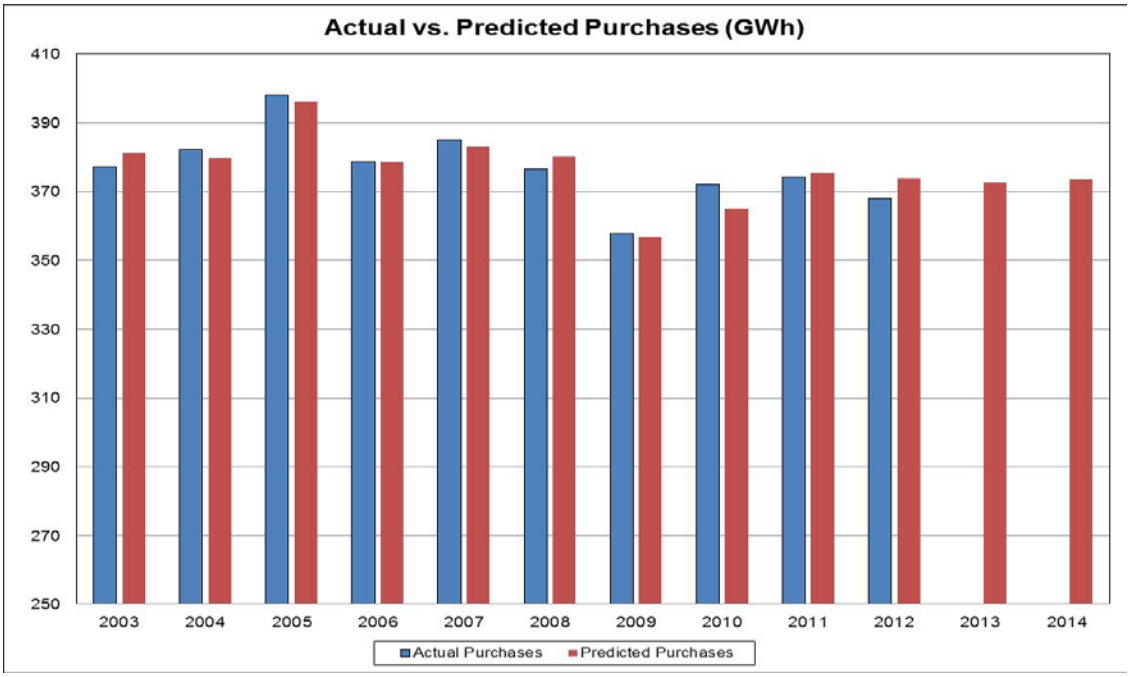
OPA 2011 Program Final Verified Results & Persistence				
2011	**2012**	**2013**	**2014**	**Total**
1,563,743	1,562,506	1,562,506	1,520,730	6,209,485
OPA 2012 Program Final Verified Results & Persistence				
2011	**2012**	**2013**	**2014**	**Total**
	1,012,284	1,009,115	1,009,114	3,030,513
OPA 2006 - 2010 Program Final Results & Persistence				
2006	**2007**	**2008**	**2009**	**2010**
1,615,000	4,219,000	5,231,000	7,867,000	8,048,000
2011	**2012**	**2013**	**2014**	**Total**
6,611,000	6,483,000	6,427,000	6,135,000	52,636,000

The prediction formula has the following statistical results:

Statistic	**Value**
R Square	91%
Adjusted R Square	91%
F Test	165.7
T-stats by Coefficient:	
Intercept	(6.0)
Heating Degree Days	13.2
Cooling Degree Days	14.6
Number of Days in Month	8.8
Spring Fall Flag	(6.1)
CDM Activity	(8.2)
Summer Months Flag	(3.0)
Employment Hamilton-Niagara Peninsula (000's)	5.9

The annual predicted purchases from 2003 to 2014 as a result of the above prediction formula compared to the actual annual purchases from 2003 to 2012 are shown in the chart below. The prediction formula has a statistical R^2 of 91% which generally indicates that the formula has a very good fit to the actual data set.

Chart



The following Table 18 outlines the data that supports the "Actual vs. Predicted Purchases" Chart above. The table also includes the 2013 and 2014 predicted system purchases for HCHI. For 2013 and 2014 the system purchases reflect a weather normalized forecast for the full year. In addition, values for 2014 are provided with a 20 year trend assumption for weather normalization. The 10 year average assumption is already provided as HCHI's 2014 test year.

Table 18
Total System Purchases

Year	Actual GWh	Predicted GWh	% Difference
2003	377.3	381.2	1.0%
2004	382.3	379.7	(0.7%)
2005	397.9	396.0	(0.5%)
2006	378.5	378.5	0.0%
2007	385.1	383.1	(0.5%)
2008	376.5	380.3	1.0%
2009	357.9	356.8	(0.3%)
2010	371.9	365.0	(1.9%)
2011	374.2	375.4	0.3%
2012	368.1	373.8	1.5%
2013 Weather Normalized - 10 Year Average		**372.6**	
2014 Weather Normalized - 10 Year Average		**373.6**	
2014 Weather Normalized - 20 Year Trend		**373.0**	

The weather normalized amount for 2014 is determined by using 2014 dependent variables in the prediction formula on a monthly basis together with the average monthly HDD and CDD that occurred from January 2003 to December 2012, the weather normalized 10 year average value. The 2014 weather normalized 20 year trend value reflects the trend in monthly HDD and CDD that occurred from January 1993 to December 2012.

The weather normalized 10 year average has been used as the purchased forecast in this Application for the purpose of determining a billed kWh load forecast which is used to design rates. The 10 year average is consistent with the period of time over which the regression analysis was conducted.

HCHI has done an analysis of load forecast models using a trend based on 20-years of HDD and CDD, and the method used in HCHI's model of calculating the average weather conditions, HDD and CDD, from 2003 to 2012, a 10 year average. Both methods were used to predict 2013 and 2014 weather normalized purchases. HCHI has chosen to remain with the original model using the 10-year average of HDD and CDD for a couple of reasons. Firstly, the other method did not produce significant

variances in the resulting billed consumption and secondly, the other method produced a lower billed consumption which would result in more significant bill impacts to the customers overall in order to recover HCHI's revenue requirement. The following Table 19 illustrates the results of the two methods:

Table 19
2014 Test Year Comparison of Load Forecast Models (HDD & CDD Methods)

HDD / CDD Method	Purchased Consumption	Loss Factor	Billed Consumption	HCHI Model Comparison
	(kWh)		(kWh)	(kWh)
HCHI - 10 Year Average (2003 to 2012)	373,636,010	1.0663	350,408,081	
20 Year Trend (1993 to 2012)	372,970,354	1.0663	349,783,807	(624,274)

Note: Billed Consumption is shown prior to reduction for 2013 and 2014 CDM program impacts

HCHI has included both load forecast models, in Excel format, as part of its 2014 COS rate application filing, in accordance with the Filing Requirements.

The details on the 10-year average monthly heating degree days and cooling degree days that HCHI incorporated into the model are shown in Appendix B, along with the 20-year trend of HDD and CDD.

Billed kWh Load Forecast

To determine the total weather normalized energy billed forecast, the total system weather normalized purchases forecast is adjusted by the "proposed" total loss factor of 1.0663, per Appendix 2-R calculations and discussed in detail in Exhibit 8, Tab 1, Schedule 4.

Applying this total loss factor ("TLF"), the total weather normalized billed energy will be 349,397,454 kWh for 2013 (i.e. 372,558,390 purchased kWh / 1.0663) and 350,408,081

kWh for 2014 (i.e. 373,636,010 purchased kWh / 1.0663) before the adjustments for the 2013 and 2014 CDM programs.

Billed kWh Load Forecast and Customer/Connection Forecast by Rate Class

Since the total weather normalized billed energy amount is known, this amount needs to be distributed by rate class for rate design purposes, taking into consideration the customer / connection forecast and expected usage per customer by rate class.

The next step in the forecasting process is to determine a customer/connection forecast. The customer/connection forecast is based on reviewing historical customer/connection data that is available for the past 10 years (i.e. 2003 to 2012) as shown in Table 20 below.

As mentioned earlier in this Exhibit, manual adjustments were made to the Residential, General Service Less Than 50 kW, and General Service 50 to 4,999 kW rate classes for services removed in 2011 and 2012 and for reclassifications between the two General Service classes. One additional adjustment was made to historical data for the Unmetered Scattered Load class for an overbilling completed in August 2013 that affected the number of connections since April 2009.

Table 20
Historical Customer / Connection Data

Year	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load	Total
2003	17,585	2,282	157	2,713	857	88	23,682
2004	17,776	2,296	157	2,777	729	81	23,816
2005	17,893	2,324	157	2,764	705	87	23,930
2006	18,026	2,311	157	2,758	693	88	24,033
2007	18,139	2,335	143	2,794	665	84	24,160
2008	18,245	2,343	145	2,879	647	84	24,343
2009	18,309	2,374	144	2,872	656	84	24,439
2010	18,465	2,363	143	3,015	594	78	24,658
2011	18,531	2,380	145	2,963	567	76	24,662
2012	18,617	2,344	150	2,982	535	73	24,701

Using the historical customer/connection data, the growth rates in customers/connections can be evaluated. The growth rates are provided by customer class in Table 21. The geometric mean growth rate is also provided in this table. The geometric mean approach provides the average compounding growth rate from 2003 to 2012. The only exception to this is in the Residential rate class where the geometric mean is the average compounding growth rate from 2004 to 2012. The growth from 2003 to 2004 in this rate class is uncharacteristic of the historical growth pattern and has been removed from the calculation.

Table 21
Growth Rate in Customers / Connections

Year	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
2003						
2004	1.1%	0.6%	0.0%	2.4%	(14.9%)	(8.0%)
2005	0.7%	1.2%	0.0%	(0.5%)	(3.3%)	7.4%
2006	0.7%	(0.6%)	0.0%	(0.2%)	(1.7%)	1.1%
2007	0.6%	1.0%	(8.9%)	1.3%	(4.0%)	(4.5%)
2008	0.6%	0.3%	1.4%	3.0%	(2.7%)	0.0%
2009	0.4%	1.3%	(0.7%)	(0.2%)	1.4%	0.0%
2010	0.9%	(0.5%)	(0.7%)	5.0%	(9.5%)	(7.1%)
2011	0.4%	0.7%	1.4%	(1.7%)	(4.5%)	(2.6%)
2012	0.5%	(1.5%)	3.4%	0.6%	(5.6%)	(3.9%)
Geometric Mean	**0.6%**	**0.3%**	**(0.5%)**	**1.1%**	**(5.1%)**	**(2.1%)**

The geometric mean was determined to be appropriate as an estimator of the 2014 customer/connection counts for the majority of the customer rate classes as shown in Table 21 above. As mentioned earlier, the 2013 Bridge Year customer/connection counts for all rate classes are actual counts as at July 31, 2013. The geometric mean was applied to this customer/connection count in order to forecast the 2014 Test Year for all classes except the Street Lighting rate class. HCHI determined that the number of street lighting connections should remain constant at the 2013 level; that is, no projection for additional connections in 2014.

Table 22 outlines the forecast of customers by rate class for 2013 and 2014.

Table 22
Customer / Connection Forecast

Year	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load	Total
2013 Weather Normal	18,664	2,356	154	2,979	529	69	24,751
2014 Weather Normal	18,772	2,363	153	2,979	502	68	24,837

The next step in the process is to review the historical customer/connection usage and to reflect this usage per customer in the forecast. The following Table 23 provides the average annual usage per customer/connection by customer rate class for the past 10 years (i.e. 2003 to 2012). The same manual adjustments mentioned above in the customer / connection forecast for the reclassification between the two General Service classes and the billing adjustment for the Unmetered Scattered Load class were applied to the historical usage prior to calculating the usage per customer / connection.

Table 23
Historical Annual Usage (kWh) per Customer / Connection

Year	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
2003	9,953	25,686	774,580	819	686	6,125
2004	9,690	24,538	830,799	789	785	6,758
2005	10,142	25,185	829,339	788	766	5,907
2006	9,516	24,544	813,976	809	745	5,769
2007	9,581	24,789	876,724	822	737	5,944
2008	9,415	24,682	821,976	809	735	5,741
2009	9,188	23,633	770,390	803	713	5,732
2010	9,324	23,776	817,909	746	675	5,823
2011	9,241	23,478	825,971	767	681	5,349
2012	9,041	23,399	788,615	801	676	5,342

From the historical usage per customer / connection data the growth rate in usage per customer/connection can be reviewed. Table 24 illustrates this growth rate as well as the geometric mean growth rate for each customer rate class.

Table 24
Growth Rate in Usage (kWh) per Customer / Connection

Year	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
2003						
2004	(2.6%)	(4.5%)	7.3%	(3.6%)	14.5%	10.3%
2005	4.7%	2.6%	(0.2%)	(0.2%)	(2.5%)	(12.6%)
2006	(6.2%)	(2.5%)	(1.9%)	2.7%	(2.6%)	(2.3%)
2007	0.7%	1.0%	7.7%	1.6%	(1.2%)	3.0%
2008	(1.7%)	(0.4%)	(6.2%)	(1.6%)	(0.2%)	(3.4%)
2009	(2.4%)	(4.3%)	(6.3%)	(0.7%)	(3.0%)	(0.2%)
2010	1.5%	0.6%	6.2%	(7.1%)	(5.3%)	1.6%
2011	(0.9%)	(1.3%)	1.0%	2.8%	0.8%	(8.1%)
2012	(2.2%)	(0.3%)	(4.5%)	4.4%	(0.6%)	(0.1%)
Geometric Mean	**(0.9%)**	**(1.0%)**	**0.2%**	**(0.2%)**	**(1.8%)**	**(1.5%)**

For the forecast of usage per customer / connection, the historical geometric mean was used for all rate classes except Street Lighting for the same reason as discussed in the customer/connection forecast above; that is, to be held constant at the last known level, which for kWh is at the 2012 level. The Residential class' geometric mean was

calculated on the same period as its customer forecast as discussed above (i.e. 2004 to 2012). For Sentinel Lighting, the geometric mean was calculated on 9 years of data instead of 10 years. If HCHI had used 10 years in the calculation, the usage per connection would be increasing which does not reflect an accurate forecast for 2014 since the historical pattern suggests connections are actually declining year over year. The forecasted usage by rate class is set out in Table 25 below.

Table 25
Forecast Annual kWh Usage per Customer / Connection

Year	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
2013	8,963	23,158	790,191	801	664	5,262
2014	8,885	22,919	791,769	801	652	5,182

With the preceding information, the non-weather normalized billed energy forecast can be determined by applying the forecast number of customer / connection from Table 22 to the forecast of annual usage per customer / connection from Table 25. The resulting non-normalized weather billed energy forecast is shown in Table 26 below.

Table 26
Non-Normalized Weather Energy Forecast (GWh)

Year	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load	Total
2013 (Not Normalized)	167.3	54.6	121.7	2.4	0.4	0.4	346.6
2014 (Not Normalized)	166.8	54.2	121.3	2.4	0.3	0.4	345.3

The non-normalized weather billed energy forecast has been determined as set out in Table 26 above but needs to be adjusted for weather sensitive load and for the impact of the 2013 and 2014 CDM programs in order to be aligned with the total weather normalized billed energy forecast. As previously determined, the total weather normalized billed energy forecast for 2013 is 349,397,454 kWh and for 2014 is

350,408,081 kWh excluding the Embedded Distributor-HONI rate class. If you include the Embedded Distributor-HONI load forecast (refer to Table 11), the total weather normalized billed energy forecast for 2013 is 421,827,943 kWh and for 2014 is 423,038,022 kWh.

Prior to applying the CDM adjustment, the difference between the non-normalized and normalized forecast is 2,769,416 kWh (349,397,454 kWh less 346,628,038 kWh) in 2013 and 5,074,701 kWh (350,408,081 kWh less 345,333,380 kWh) in 2014. This difference is assumed to be associated with moving the forecast from a non-normalized to a weather normalized basis and will be assigned to those rate classes that are weather sensitive. Based on the weather normalization work completed by Hydro One Networks Inc., on behalf of HCHI for its Cost Allocation Study filed in February 2007 with the OEB, the weather sensitivity by rate classes was determined as set out in Table 27 below.

Table 27
Weather Sensitivity by Rate Class

Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
Weather Sensitivity					
71.0%	71.0%	42.0%	0.0%	0.0%	0.0%

Hydro One Networks Inc. determined the General Service 50 to 4,999 kW customer rate class to be 42% weather sensitive. For the Residential and General Service Less Than 50 kW customer rate classes it has been assumed in previous COS rate applications that these two classes are 100% weather sensitive. Intervenors expressed concern with this assumption and have suggested that 100% weather sensitivity is not appropriate. HCHI agrees with this position but also submits that the weather sensitivity for the Residential and General Service Less Than 50 kW should be higher than the General Service 50 to 4,999 kW customer rate class. As a result, HCHI has assumed

the weather sensitivity for the Residential and General Service Less Than 50 kW customer rate classes to be mid-way between 100% and 42%, or 71%. The Sentinel Lighting, Street Lighting, and Unmetered Scattered Load customer rate classes are considered to be 0% weather sensitive. The Embedded Distributor-HONI rate class, although not included in the above table, is also considered not to be weather sensitive.

The difference between the non-normalized and normalized forecast has been assigned on a prorated basis to each rate class based on the above level of weather sensitivity.

In addition, a manual adjustment has been made to reflect the impact of 2013 and 2014 CDM programs on the load forecast. HCHI has made this adjustment to reflect the "net" energy savings of 2013 and 2014 CDM programs on the load forecast. As previously discussed, the 2011 and 2012 savings from 2011 CDM programs and 2012 savings from 2012 CDM programs are known and have been used in the CDM activity variable included in the regression analysis supporting the prediction formula. However, knowing the 2011 and 2012 program results determines the savings that will be needed from 2013 and 2014 programs in order to achieve the licensed 4 year CDM target of 13,300,000 kWh assigned to HCHI, as a condition of its electricity distribution licence.

Based on the following table, the 2011 and 2012 CDM programs will contribute 46.7% and 22.8%, respectively, to the four year target. In the following Table 28, the 2011 and 2012 program results are consistent with the information provided in Table 17. Table 28 indicates that assuming persistence, 2013 programs will need to achieve 10.2% of the four year target in each of 2013 and 2014, and 2014 programs will need to achieve 10.2% of the four year target in 2014 in order to achieve the cumulative four year target by the end of 2014.

The kWh for all CDM programs detailed in Table 28 below are on a net energy savings basis.

Table 28
Schedule to Achieve 4 Year CDM Target

4 Year 2011 to 2014 CDM Target - 13,300,000 kWh					
	2011	**2012**	**2013**	**2014**	**Total**
2011 Programs	11.8%	11.7%	11.7%	11.4%	46.7%
2012 Programs		7.6%	7.6%	7.6%	22.8%
2013 Programs			10.2%	10.2%	20.4%
2014 Programs				10.2%	10.2%
	11.8%	19.4%	29.5%	39.4%	100.0%
kWh					
2011 Programs	1,563,743	1,562,506	1,562,506	1,520,730	6,209,485
2012 Programs		1,012,284	1,009,115	1,009,114	3,030,513
2013 Programs			1,353,334	1,353,334	2,706,668
2014 Programs				1,353,334	1,353,334
	1,563,743	2,574,790	3,924,955	5,236,512	13,300,000

Based on the approved method used in the 2013 COS rate applications, the savings for the 2013 Bridge Year will be one half of the 2012 programs (1,009,115 / 2 = 504,558 kWh) plus one half of the 2013 programs (1,353,334 / 2 = 676,667 kWh) for a total net energy savings of 1,181,225 kWh. In HCHI's view, the 2013 Bridge Year load forecast should be adjusted by 1,181,225 kWh to reflect CDM savings.

Also based on the approved method used in the 2013 COS rate applications, Table 28 also suggests that in 2014 the savings will be one half of the 2012 programs (1,009,114 / 2 = 504,557 kWh), plus a full year of 2013 programs (1,353,334 kWh) plus one half of the 2014 programs (1,353,334 / 2 = 676,667 kWh) for a total net energy savings of 2,534,558 kWh. It is also HCHI's view that the 2014 Test Year load forecast should be adjusted by 2,534,558 kWh to reflect CDM savings. These same CDM savings for the 2014 Test Year are as calculated and included in Appendix 2-I "Load Forecast CDM Work Form".

The 2013 Bridge Year and the 2014 Test Year CDM net energy savings reflected in the load forecast have been allocated to the three customer rate classes - based on HCHI's 2012 CDM program results provided by the OPA August 1, 2013 in the report "OPA Annual CDM Report 2012 – Draft Verified Results" ("OPA Report") - Residential (27%), General Service Less Than 50 kW (46%), and General Service 50 to 4,999 kW (27%).

The allocation to the three customer rate classes was based on the "Program-to-Date Verified Progress to Target" 2011 to 2014 net cumulative energy savings (kWh) by program as detailed in the 2012 OPA Report. The OPA reports the results within four main program groupings; Residential, Business, Industrial, and Low-Income. These program groupings partially map to the customer rate classes. Some initiatives apply to more than one customer rate class, such as the Retrofit initiative under the Business programs. Where this occurred, HCHI estimated the customer rate class allocation by utilizing participant-specific information. For example, the Retrofit initiative was split 50 / 50 between the two General Service customer rate classes.

The 2014 Test Year program net energy savings of 1,353,334 kWh (refer to Table 28) was used as the base to calculate the allocation percentages per rate class to be used in the load forecast model. The 1,353,334 kWh was allocated to initiatives based on each initiative's share of the 2011 to 2014 total net cumulative energy savings. The 2014 net energy savings by initiative was then allocated to rate classes as discussed in the paragraph above. These allocations resulted in the percentages for each of the three rate classes noted already - Residential (27%), General Service Less Than 50 kW (46%), and General Service 50 to 4,999 kW (27%). Table 29 illustrates the allocation of the CDM savings to each rate class for the both the 2013 Bridge Year and the 2014 Test Year.

Table 29
2013 and 2014 CDM Savings Allocation by Customer Rate Class

	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Total
	27%	46%	27%	
2013 Bridge Year	317,631	546,553	317,041	1,181,225
2014 Test Year	681,543	1,172,740	680,275	2,534,558

In accordance with the Board's Guidelines for Electricity Distributor Conservation and Demand Management, (EB-2012-0003), issued on April 26, 2012, it is HCHI's

understanding that, as part of this Application, expected CDM savings in 2014 from 2011, 2012, 2013, and 2014 programs will need to be established for Lost Revenue Adjustment Mechanism ("LRAM") variance accounts purposes. HCHI also understands that the OPA will measure CDM results attributable to the four year targets on a net basis. Consistent with past practices, it is expected the net level of savings will be used for LRAM calculations. As a result, it is HCHI's view that the units used for the 2014 LRAM variance account should also be on a net basis. Based on the net information in Table 28, HCHI expects to achieve 5,236,512 net kWh savings in 2014 from the 2011 through to 2014 CDM programs. For LRAM variance account purposes, the following Table 30 outlines how this expected net savings has been allocated to the rate classes using the 2014 information from Table 29. The expected kW saving has also been provided for those classes where the distribution volumetric charge billing determinant is on a kW basis, using the average kW per kWh factors in Table 33.

Table 30
2014 Expected Savings for LRAM Variance Account

	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Total
	27%	46%	27%	
kWh	1,408,098	2,422,934	1,405,480	5,236,512
kW where applicable			3,948	3,948

The following Table 31 indicates how the weather sensitive rate classes have been adjusted to align the non-normalized forecast with the normalized forecast and reflect the CDM adjustments discussed above in Table 29.

Table 31
Alignment of Non-Normalized to Weather-Normalized Energy Forecasts

Year	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load	Total
2013 Non-Normalized Bridge	167.3	54.6	121.7	2.4	0.4	0.4	346.6
2014 Non-Normalized Test	166.8	54.2	121.3	2.4	0.3	0.4	345.3
Weather Adjustment (GWh)							
2013	1.6	0.5	0.7	0.0	0.0	0.0	2.8
2014	2.9	0.9	1.2	0.0	0.0	0.0	5.1
CDM Adjustment (GWh)							
2013	(0.3)	(0.5)	(0.3)	0.0	0.0	0.0	(1.2)
2014	(0.7)	(1.2)	(0.7)	0.0	0.0	0.0	(2.5)
Weather Normalized Billed Energy Forecast (GWh)							
2013 Normalized Bridge	**168.5**	**54.5**	**122.1**	**2.4**	**0.4**	**0.4**	**348.2**
2014 Normalized Test	**169.0**	**53.9**	**121.9**	**2.4**	**0.3**	**0.4**	**347.9**

Billed kW Load Forecast

There are a number of customer rate classes where the distribution volumetric charge billing determinant is on a per kW basis. These include General Service 50 to 4999 kW, Street Lighting and Sentinel Lighting. As a result, the energy forecast for these classes needs to be converted to a kW basis for rate setting purposes. The forecast of kW for these rate classes is based on a review of the historical ratio of kW to kWh and applying the average ratio to the forecasted kWh to produce the required kW.

The following Table 32 provides the annual demand units by applicable rate class for the years 2003 to 2012.

Table 32
Historical Annual kW per Applicable Customer Rate Class

Year	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Total
2003	330,005	6,047	1,718	337,770
2004	364,630	6,089	1,578	372,297
2005	366,007	5,668	1,482	373,157
2006	367,812	6,222	1,423	375,457
2007	347,081	6,403	1,361	354,845
2008	327,985	6,475	1,313	335,773
2009	321,434	6,468	1,293	329,195
2010	329,361	6,542	1,110	337,013
2011	336,851	6,601	1,069	344,521
2012	336,349	6,620	1,003	343,972

The following Table 33 provides the historical ratio of kW to kWh as well as the average ratio for 2003 to 2012.

Table 33
Historical Ratio of kW to kWh per Applicable Customer Rate Class

Year	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting
2003	0.2714%	0.2723%	0.2922%
2004	0.2795%	0.2778%	0.2757%
2005	0.2811%	0.2603%	0.2746%
2006	0.2878%	0.2787%	0.2754%
2007	0.2768%	0.2787%	0.2778%
2008	0.2752%	0.2780%	0.2761%
2009	0.2897%	0.2805%	0.2764%
2010	0.2816%	0.2908%	0.2767%
2011	0.2813%	0.2903%	0.2770%
2012	0.2843%	0.2770%	0.2772%
Average 2003 to 2012	**0.2809%**	**0.2784%**	**0.2779%**

The average ratio was applied to the weather normalized billed energy forecast for 2013 and 2014 in Table 30 to provide the forecast of kW for the applicable customer rate classes as shown in Table 34 below.

Table 33
Forecast of kW by Applicable Customer Rate Class

Year	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Total
2013 Normalized Bridge	342,804	6,648	976	350,428
2014 Normalized Test	342,324	6,648	909	349,881

Embedded Distributor – Hydro One Networks Inc. Load Forecast

As mentioned earlier in this Exhibit, HONI supplied HCHI with an existing weather normalized load forecast that has been previously used by HONI for their own purposes, including both kWh and kW, for all embedded points for the 2013 Bridge Year and the 2014 Test Year. HCHI has used HONI's forecast in this Application. The following Table 35 provides details of the actual activity for the period 2009 to 2012 and Table 36 provides details of the forecast provided by HONI to HCHI.

Table 35
Actual Information for Embedded Distributor – HONI

Year	Customer Number	kWh	kW
2009 (March to December)	8	56,044,835	334,545
2010	8	73,870,537	241,211
2011	8	74,192,250	264,787
2012	8	71,831,928	245,804

Note: 2009 is a partial year. HONI became embedded to HCHI in March 2009 for 7 of the 8 points with the last point becoming embedded in April 2009.

Table 36
Load Forecast Information for Embedded Distributor – HONI

	HONI Forecasted Weather Normalized Load					
	2013 Bridge Year			2014 Test Year		
HONI Supply Points (Embedded to HCHI)	Customer Count	kWh	kW	Customer Count	kWh	kW
3rd Line PME	1	9,695,803	19,823	1	9,700,997	19,834
4th Line PME	1	2,872,521	6,224	1	2,876,809	6,235
5th Line PME	1	3,006,659	6,156	1	3,015,665	6,177
6th Line PME	1	3,381,185	6,820	1	3,385,013	6,828
Canadian Gypsum	1	39,022,081	83,218	1	39,183,165	83,514
Domtar Mill PME (Georgia Pacific)	1	9,312,408	38,384	1	9,326,840	38,462
Greens Road PME	1	5,139,831	11,600	1	5,141,453	11,606
	7	72,430,489	172,225	7	72,629,941	172,657
Air Products	1		55,024	1		55,057
Totals	**8**	**72,430,489**	**227,250**	**8**	**72,629,941**	**227,715**
		2009 Bridge kWh	2009 Bridge kW		2010 Test kWh	2010 Test kW
2010 Board Approved	8	81,924,442	274,235	8	83,184,875	276,949

Table 12 on page 2 of this Schedule summarizes the consumption and customer /connection data for each rate class, including the Embedded Distributor-HONI, for the 2010 Board Approved, 2010 Actual, 2011 Actual, 2012 Actual, and weather normalized 2013 Bridge Year and 2014 Test Year.

Transformer Ownership Allowance

HCHI currently provides a Transformer Ownership Allowance Credit of $0.60 per kW of billing demand per month for customers who own their own transformer facilities.

HCHI is proposing to maintain the rate of $0.60 per kW of billing demand per month for the 2014 Test Year for all eligible customers.

OTHER OPERATING REVENUE

Table 37 below summarizes Other Operating Revenues included in HCHI's Total Revenue Requirement. The data in this table provides a breakdown of the "Total Other Revenue" line in Table 1 of this Exhibit.

Table 37
Summary of Other Operating Revenue

USoA #	USoA Description	2010 Actual	2011 Actual	2012 Actual[2]	Bridge Year[3]	Test Year
					2013	2014
	Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
4235	Specific Service Charges	$ 136,247	$ 109,529	$ 122,565	$ 120,859	$ 120,987
4225	Late Payment Charges	349,416	289,018	319,383	310,717	310,717
4082	Retail Services Revenue	31,747	29,584	26,639	28,640	26,720
4084	STR Revenues	1,045	841	498	1,110	1,010
4086	SSS Administration Revenue	64,723	65,103	58,184	67,716	68,148
4210	Rent from Electric Property	80,923	86,987	76,396	79,376	76,226
4305	Regulatory Debits				(1,459,184)	
4324	Special Purpose Charge Recovery	94,692	46,517			
4325	Revenues from Merchandise	18,976	22,402	19,646	16,873	16,873
4355	Gain on Disposition of Utility & Other Property	12,203	24,427	114,495	5,603	13,940
4360	Loss on Disposition of Utility & Other Property	(6,685)	(3,078)	(1,959)		
4375	Revenues from Non Rate-Regulated Utility Operations	365,737	364,650	374,857	374,205	374,205
4380	Expenses of Non Rate-Regulated Utility Operations	(1)				
4390	Miscellaneous Non-Operating Income	68,196	144,190	154,277	74,308	90,585
4405	Interest and Dividend Income	27,884	28,211	42,514	34,260	38,650
Specific Service Charges		$ 136,247	$ 109,529	$ 122,565	$ 120,859	$ 120,987
Late Payment Charges		$ 349,416	$ 289,018	$ 319,383	$ 310,717	$ 310,717
Other Operating Revenues		$ 178,438	$ 182,515	$ 161,717	$ 176,842	$ 172,104
Other Income and Deductions		$ 581,002	$ 627,319	$ 703,830	$ (953,935)	$ 534,253
Total		**$ 1,245,103**	**$ 1,208,381**	**$ 1,307,495**	**$ (345,517)**	**$ 1,138,061**

Note to Table 1, Table 3, Table 37 and Table 38:

1. The following revenue and / or cost accounts associated with deferral and variance accounts and with non-distribution CDM activities, namely the OPA funded CDM programs, have not been included in Other Operating Revenues:

   a) 4405 - OEB Deferred Interest on Deferral and Variance Accounts
   b) 4375 - Revenues from Non-Utility Operations – OPA CDM Programs
   c) 4380- Expenses on Non-Utility Operations – OPA CDM Programs

The following Table 38 provides a further detailed breakdown for each "Other Operating Revenues" and "Other Income and Deductions" account as summarized in Table 36 above.

Table 38
Detailed Account Breakdown

	2010 Actual	2011 Actual	2012 Actual	2013 Bridge	2014 Test
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**
Account 4082 - Retail Service Revenue					
Retail Service Agreement Revenue	31,747	29,584	26,639	28,640	26,720
Total	31,747	29,584	26,639	28,640	26,720
Account 4084 - STR Revenue					
Retail Service Transaction Requests (STR) Revenue	1,045	841	498	1,110	1,010
Total	1,045	841	498	1,110	1,010
Account 4086 - SSS Administration Revenue					
SSS Administration Revenue	64,723	65,103	58,184	67,716	68,148
Total	64,723	65,103	58,184	67,716	68,148
Account 4210 - Rent from Electric Property					
Pole Rental Revenue	80,923	86,987	76,396	79,376	76,226
Total	80,923	86,987	76,396	79,376	76,226
TOTAL OTHER OPERATING REVENUE	**178,438**	**182,515**	**161,717**	**176,842**	**172,104**
Account 4305 - Regulatory Debits					
PPE Useful Lives Adjustment (effective January 1, 2013)				(1,459,184)	
Total	-	-	-	(1,459,184)	-
Account 4324 - Special Purpose Charge Recovery					
Special Purpose Charge Recovery	94,692	46,517			
Total	94,692	46,517	-	-	-
Account 4325 - Revenues from Merchandis, Jobbing, Etc.					
Profit from Sale of Services	18,976	22,402	19,646	16,873	16,873
Total	18,976	22,402	19,646	16,873	16,873
Account 4355 - Gain on Disposition of Utility & Other Property					
Gain on Disposal of Other Property	12,203	24,427	114,495	5,603	13,940
Total	12,203	24,427	114,495	5,603	13,940
Account 4360 - Loss on Disposition of Utility & Other Property					
Loss on Disposal of Other Property	(6,685)	(3,078)	(1,959)		
Total	(6,685)	(3,078)	(1,959)	-	-
Account 4375 - Revenues from Non-Rate Regulated Operations					
Revenue from Water & Sewer Admin Fee (85%)	365,737	364,650	374,857	374,205	374,205
Total	365,737	364,650	374,857	374,205	374,205
Account 4380 - Expenses from Non-Rate Regulated Utility Opera					
Write-off of Balance in '1590' RAR account - activity after disposition approval unrecoverable	(1)				
Total	(1)	-	-	-	-
Account 4390 - Miscellaneous Non-Operating Income					
Revenues from Long-term Load Transfers	59,422	59,538	92,807	41,319	52,400
Revenues from Short-term Load Transfers		74,704	52,644		
Revenue from Lawyers Letters	1,860	1,965	2,370	2,420	2,487
Proceeds - from sale of Enerconnect Limited Partnership	4,775	4,736			
Revenue from Theft of Power		2,482	747		
"Caledonia Class Action" settlement compensation award - Douglas Creek Estates (Native occupation)			5,000		
Revenue from Generator Admin Fees (RESOP, FIT, HOEP)				30,538	35,663
Other Miscellaneous Income	2,139	765	709	31	35
Total	68,196	144,190	154,277	74,308	90,585
Account 4405 - Interest and Dividend Income					
Interest on Bank Account	27,332	27,529	41,984	33,786	38,188
Mortgage Interest	552	545	530	474	462
Miscellaneous Interest		137			
Total	27,884	28,211	42,514	34,260	38,650
TOTAL OTHER INCOME AND DEDUCTIONS	**581,002**	**627,319**	**703,830**	**(953,935)**	**534,253**

Other Operating Revenue Variance Analysis

The materiality threshold used in the analysis of Other Operating Revenue is the same one used throughout HCHI's entire 2014 COS rate application; that is, $64,000, in accordance with the Filing Guidelines, calculated as 0.5% of distribution revenue requirement. Table 39 and Table 40 provide the variance analysis on the Other Operating Revenue accounts. The only difference between the Tables 39 and 40 is the exclusion of the PPE adjustment on account of HCHI's change in useful lives from the Other Income and Deductions line in the amount of $1,459,184 in 2013. This amount is distorting the variance analysis between the 2013 Bridge Year and 2012 Actual and the 2014 Test Year. Detailed explanation of the variances exceeding the materiality threshold follows the two tables.

Table 39
Other Operating Revenue with Variances

Description	2010 Board Approved	2010 Actual Year	Variance from Board Approved	2011 Actual Year	Variance from 2010 Actual	2012 Actual Year	Variance from 2011 Actual	2013 Bridge Year	Variance from 2012 Actual	2014 Test Year	Variance from 2013 Bridge
Other Revenue:											
Late Payment Charges	319,125	349,416	30,291	289,018	(60,398)	319,383	30,365	310,717	(8,666)	310,717	-
Specific Service Charges	133,200	136,247	3,047	109,529	(26,718)	122,565	13,036	120,859	(1,706)	120,987	128
Other Operating Revenue	183,821	178,438	(5,383)	182,515	4,077	161,717	(20,798)	176,842	15,125	172,104	(4,738)
Other Income and Deductions	452,998	581,002	128,004	627,319	46,317	703,830	76,511	(953,935)	(1,657,765)	534,253	1,488,188
Total Other Revenue	1,089,144	1,245,103	155,959	1,208,381	(36,722)	1,307,495	99,114	(345,517)	(1,653,012)	1,138,061	1,483,578
Variance from 2010 Board Approved		14.32%		10.95%		20.05%		(131.72%)		4.49%	
Variance from Prior Year				(2.95%)		8.20%		(126.43%)		(429.38%)	

Table 40
Other Operating Revenue with Variances
(Excluding PPE Adjustment)

Description	2010 Board Approved	2010 Actual Year	Variance from Board Approved	2011 Actual Year	Variance from 2010 Actual	2012 Actual Year	Variance from 2011 Actual	2013 Bridge Year	Variance from 2012 Actual	2014 Test Year	Variance from 2013 Bridge
Other Revenue:											
Late Payment Charges	319,125	349,416	30,291	289,018	(60,398)	319,383	30,365	310,717	(8,666)	310,717	-
Specific Service Charges	133,200	136,247	3,047	109,529	(26,718)	122,565	13,036	120,859	(1,706)	120,987	128
Other Operating Revenue	183,821	178,438	(5,383)	182,515	4,077	161,717	(20,798)	176,842	15,125	172,104	(4,738)
Other Income and Deductions	452,998	581,002	128,004	627,319	46,317	703,830	76,511	505,249	(198,581)	534,253	29,004
Total Other Revenue	1,089,144	1,245,103	155,959	1,208,381	(36,722)	1,307,495	99,114	1,113,667	(193,828)	1,138,061	24,394
Variance from 2010 Board Approved		14.32%		10.95%		20.05%		2.25%		4.49%	
Variance from Prior Year				(2.95%)		8.20%		(14.82%)		2.19%	

2010 Actual versus 2010 Board Approved:

The 2010 Actual increased by $128,004 over the 2010 Board Approved in Other Income and Deductions. The major contributor to the variance is account 4324 - Special Purpose Charge Recovery in the amount of $94,692. In April 2010 the Board issued a letter regarding the Ministry of Energy and Infrastructure ("MEI") Special Purpose Charge ("SPC") Assessment and invoice to distributors setting out the amount that each was assessed in respect of expenditures for conservation programs delivered by the MEI. Distributors were allowed to recover the assessment amount from their customers and HCHI began billing for this charge at the end of May 2010 to continue for a one year period for all customers except the Embedded Distributor - HONI. This assessment was not anticipated when the 2010 COS application was prepared and therefore no recovery from customers was included in Other Operating Revenue in the 2010 COS application.

2011 Actual versus 2010 Actual:

No variances exceeding materiality threshold.

2012 Actual versus 2011 Actual:

The variance between 2011 Actual and 2012 Actual in Other Income and Deductions is an increase of $76,511. This variance is on account of a gain realized in the amount of $98,913 when a parcel of land was disposed of in November 2012.

2013 Bridge Year versus 2012 Actual:

After removing the PPE adjustment of $1,459,184 for the mandatory regulatory accounting change for estimated useful lives, the variance is still a decrease of $198,581 from the 2012 Actual to the 2013 Bridge Year (refer to Table 39). This variance is partly on account of the gain realized in 2012 on account of the disposal of land. The only disposal forecasted for 2013 is one truck with an estimated gain of $5,603 based on historical truck disposals. The balance of the variance is on account of distribution revenue received in 2012 for long-term and short-term load transfers. HCHI does not forecast any short-term load transfers ("STLT") for the 2013 Bridge Year as they occur at the request of HONI as required. In 2012, HCHI received $52,644 in Miscellaneous Non-Operating Revenue from HONI on account of STLTs where $0 is forecasted for 2013.

In 2012, two years of revenue were booked to Miscellaneous Non-Operating Revenue in the amount of $92,807 on account of long-term load transfers ("LTLT"). In the fall of 2012, HCHI was subject to a Board Group 1 Deferral and Variance Account audit that reviewed the balances in those accounts as at December 31, 2011. HCHI has always booked the LTLTs in the first quarter of the year following the LTLT consumption year when actual numbers were known. The Board's audit team instructed HCHI to accrue for an estimate of that year's LTLTs and true-up to actual in the first quarter of the following year. This resulted in the 2011 actual LTLTs booked in 2012 and the 2012 LTLTs accrued in 2012 resulting in an additional $40,410 of income. The 2013 Bridge Year contains the forecasted accrual for the 2013 LTLTs.

2014 Test Year versus 2013 Bridge Year:

The only variance between the 2013 Bridge Year and the 2014 Test Year is on account of the PPE adjustment for the mandatory regulatory accounting change in estimated useful lives effective January 1, 2013. Once the $1,459,184 adjustment is removed (refer to Table 40) the variance of $29,004 is immaterial.

Specific Service Charges

HCHI is proposing no changes to the current Board Approved rates for specific service charges, as indicated in Exhibit 8, Tab 1, Schedule 3, and no new charges are proposed.

Revenues from Affiliate Transactions, Shared Services, Corporate Cost Allocation

HCHI's affiliate, Haldimand County Energy Inc. ("HCEI"), contracts HCHI to provide water and wastewater billing and collecting services on its behalf for the Shareholder, Haldimand County. HCEI pays HCHI a set fee per customer bill for this service which is 85% of the fee that HCEI charges to Haldimand County. This set fee is reviewed annually and is calculated using direct and indirect costs related to the service allocated based on the number of water customers to the total water and electric customers. The costs associated with this service are discussed in more detail in Exhibit 4, Tab 2, Schedule 5.

The revenue for this service is recorded in account 4375 – Revenues from Non-Rate Regulated Operations as detailed in Table 38.

APPENDIX A
Monthly Regression Analysis Data

	Purchased	Heating Degree Days	Cooling Degree Days	Number of Days in Month	Spring Fall Flag	CDM Activity	Summer Months Flag	Employment Hamilton-Niagara Peninsula (000's)	Predicted Purchases
Jan-03	36,662,669	829.5	0.0	31	0	0	0	658	37,352,969
Feb-03	32,216,878	699.2	0.0	28	0	0	0	659	32,658,355
Mar-03	32,592,426	593.1	0.0	31	1	0	0	662	32,512,730
Apr-03	28,484,458	387.1	0.0	30	1	0	0	664	29,161,320
May-03	27,549,364	215.8	0.0	31	1	0	0	669	28,515,137
Jun-03	28,594,490	54.5	41.4	30	0	0	1	677	29,342,101
Jul-03	33,152,864	6.5	83.9	31	0	0	1	686	33,242,702
Aug-03	33,546,964	5.7	102.6	31	0	0	1	693	34,876,240
Sep-03	28,300,069	73.9	14.8	30	1	0	0	691	27,889,250
Oct-03	29,570,748	293.5	0.0	31	1	0	0	688	30,333,465
Nov-03	30,816,096	391.5	0.0	30	1	0	0	680	29,979,653
Dec-03	35,841,514	571.0	0.0	31	0	0	0	678	35,328,617
Jan-04	38,418,884	859.1	0.0	31	0	0	0	671	38,316,217
Feb-04	33,440,258	647.7	0.0	29	0	0	0	661	33,238,342
Mar-04	32,352,926	513.6	0.0	31	1	0	0	653	31,160,414
Apr-04	28,034,857	329.3	0.0	30	1	0	0	654	28,042,719
May-04	28,679,952	164.1	14.2	31	1	0	0	667	28,849,918
Jun-04	28,777,312	60.1	29.2	30	0	0	1	681	28,795,359
Jul-04	32,245,498	7.7	71.6	31	0	0	1	695	32,853,416
Aug-04	31,231,984	28.9	40.0	31	0	0	1	701	31,199,329
Sep-04	29,977,471	43.9	31.2	30	1	0	0	702	29,239,730
Oct-04	30,210,596	253.5	0.0	31	1	0	0	700	30,458,269
Nov-04	31,443,174	396.0	0.0	30	1	0	0	694	30,722,801
Dec-04	37,443,528	636.7	0.0	31	0	0	0	694	36,871,444
Jan-05	38,588,370	765.8	0.0	31	0	0	0	684	37,841,357
Feb-05	32,788,470	641.7	0.0	28	0	0	0	682	33,093,577
Mar-05	33,560,529	646.9	0.0	31	1	0	0	667	33,356,631
Apr-05	28,067,410	339.0	0.0	30	1	0	0	669	28,845,301
May-05	28,033,376	212.7	0.0	31	1	0	0	673	28,703,916
Jun-05	34,051,463	13.1	119.6	30	0	0	1	690	34,916,490
Jul-05	38,068,287	1.1	144.7	31	0	0	1	697	37,952,552
Aug-05	35,835,110	3.8	102.5	31	0	0	1	699	35,157,680
Sep-05	30,006,887	32.8	25.6	30	1	0	0	694	28,353,126
Oct-05	29,588,399	234.2	7.6	31	1	0	0	690	30,281,943
Nov-05	31,614,193	396.3	0.0	30	1	0	0	687	30,392,299
Dec-05	37,747,216	688.8	0.0	31	0	0	0	686	37,056,676
Jan-06	35,087,685	554.7	0.0	31	0	20,705	0	683	35,318,757
Feb-06	32,387,946	602.8	0.0	28	0	41,410	0	677	32,276,742
Mar-06	32,659,459	530.4	0.0	31	1	62,115	0	672	32,063,045
Apr-06	26,787,901	314.6	0.0	30	1	82,821	0	672	28,480,301
May-06	27,503,587	155.5	22.4	31	1	103,526	0	684	29,772,121
Jun-06	29,952,375	26.7	43.2	30	0	124,231	1	698	29,763,971
Jul-06	36,277,085	1.9	136.1	31	0	144,936	1	706	37,308,716
Aug-06	33,329,530	8.1	70.1	31	0	165,641	1	707	32,772,745
Sep-06	28,064,773	105.3	4.1	30	1	186,346	0	699	27,325,644
Oct-06	30,233,031	304.1	0.0	31	1	207,051	0	694	30,053,287
Nov-06	31,587,658	393.1	0.0	30	1	227,756	0	683	29,439,121
Dec-06	34,663,730	508.1	0.0	31	0	248,462	0	681	33,974,478

	Purchased	Heating Degree Days	Cooling Degree Days	Number of Days in Month	Spring Fall Flag	CDM Activity	Summer Months Flag	Employment Hamilton-Niagara Peninsula (000's)	Predicted Purchases
Jan-07	35,889,158	665.6	0.0	31	0	264,326	0	674	35,384,740
Feb-07	34,017,544	761.8	0.0	28	0	280,191	0	672	33,094,170
Mar-07	32,604,794	565.2	0.0	31	1	296,056	0	671	31,657,803
Apr-07	28,644,659	374.2	0.0	30	1	311,921	0	680	28,774,861
May-07	27,938,156	138.4	23.3	31	1	327,786	0	694	29,415,830
Jun-07	32,019,209	19.2	74.2	30	0	343,651	1	706	31,487,793
Jul-07	32,377,216	9.2	82.0	31	0	359,516	1	714	33,317,046
Aug-07	35,026,642	8.4	106.0	31	0	375,381	1	715	34,989,551
Sep-07	29,896,811	55.2	37.2	30	1	391,246	0	711	28,940,852
Oct-07	29,518,757	157.8	13.0	31	1	407,110	0	710	29,403,131
Nov-07	30,921,288	467.5	0.0	30	1	422,975	0	705	30,694,403
Dec-07	36,272,681	641.0	0.0	31	0	438,840	0	703	35,918,797
Jan-08	35,810,334	633.6	0.0	31	0	438,390	0	697	35,530,361
Feb-08	32,883,861	678.8	0.0	29	0	437,941	0	693	33,706,430
Mar-08	31,938,647	620.7	0.0	31	1	437,491	0	690	32,756,218
Apr-08	28,132,254	288.1	0.0	30	1	437,041	0	696	28,145,303
May-08	27,152,520	214.1	0.3	31	1	436,591	0	705	28,829,040
Jun-08	30,002,892	34.2	55.0	30	0	436,142	1	720	30,704,209
Jul-08	34,123,826	3.7	87.7	31	0	435,692	1	726	34,013,422
Aug-08	31,806,390	20.2	45.2	31	0	435,242	1	730	31,457,145
Sep-08	28,611,094	70.5	19.8	30	1	434,792	0	722	28,314,513
Oct-08	28,851,748	297.5	0.0	31	1	434,342	0	717	30,365,081
Nov-08	30,694,201	460.6	0.0	30	1	433,893	0	705	30,551,668
Dec-08	36,473,843	655.3	0.0	31	0	433,443	0	699	35,880,228
Jan-09	37,800,450	852.3	0.0	31	0	467,618	0	687	37,477,719
Feb-09	31,014,616	616.6	0.0	28	0	501,794	0	678	31,019,652
Mar-09	31,556,113	540.9	0.0	31	1	535,969	0	675	30,805,844
Apr-09	26,612,954	334.7	1.7	30	1	570,145	0	677	27,483,340
May-09	28,595,342	178.1	0.0	31	1	604,320	0	688	27,058,616
Jun-09	22,744,026	58.5	30.2	30	0	638,496	1	697	27,505,206
Jul-09	28,883,171	18.9	21.7	31	0	672,671	1	701	27,636,979
Aug-09	32,377,531	18.1	69.7	31	0	706,847	1	702	30,878,286
Sep-09	27,558,765	67.9	13.3	30	1	741,022	0	699	25,720,350
Oct-09	27,805,774	310.4	0.0	31	1	775,197	0	704	28,782,354
Nov-09	28,184,886	371.7	0.0	30	1	809,373	0	701	28,161,107
Dec-09	34,747,296	643.6	0.0	31	0	843,548	0	695	34,255,483
Jan-10	35,055,255	728.7	0.0	31	0	816,951	0	684	34,779,735
Feb-10	29,919,682	618.4	0.0	28	0	790,354	0	675	29,960,706
Mar-10	29,292,829	456.8	0.0	31	1	763,757	0	672	28,989,915
Apr-10	25,438,255	235.8	0.8	30	1	737,160	0	673	25,555,833
May-10	28,347,227	128.4	28.8	31	1	710,562	0	683	27,893,060
Jun-10	30,191,753	27.2	44.8	30	0	683,965	1	699	28,140,088
Jul-10	36,390,487	5.7	121.6	31	0	657,368	1	707	34,741,724
Aug-10	34,769,307	6.9	95.6	31	0	630,771	1	712	33,260,995
Sep-10	28,631,798	97.2	24.2	30	1	604,174	0	705	27,547,345
Oct-10	28,407,067	260.8	0.0	31	1	577,577	0	703	28,800,995
Nov-10	29,515,329	416.7	0.0	30	1	550,979	0	699	29,399,965
Dec-10	35,981,970	695.9	0.0	31	0	524,382	0	696	35,940,952

	Purchased	Heating Degree Days	Cooling Degree Days	Number of Days in Month	Spring Fall Flag	CDM Activity	Summer Months Flag	Employment Hamilton-Niagara Peninsula (000's)	Predicted Purchases
Jan-11	35,989,667	804.3	0.0	31	0	548,512	0	692	36,906,442
Feb-11	31,141,596	660.1	0.0	28	0	572,643	0	686	31,636,348
Mar-11	31,649,297	596.7	0.0	31	1	596,773	0	685	31,710,049
Apr-11	27,185,313	354.0	0.0	30	1	620,903	0	692	28,109,325
May-11	27,343,107	158.6	13.3	31	1	645,033	0	706	28,497,927
Jun-11	29,398,937	25.0	40.0	30	0	669,163	1	719	28,794,098
Jul-11	37,223,618	0.0	163.7	31	0	693,294	1	724	38,304,863
Aug-11	33,862,517	2.4	83.2	31	0	717,424	1	718	32,391,071
Sep-11	28,854,389	68.7	26.8	30	1	741,554	0	715	27,420,765
Oct-11	28,619,487	256.0	0.0	31	1	765,684	0	715	28,739,890
Nov-11	29,539,702	349.2	0.0	30	1	789,815	0	719	28,811,451
Dec-11	33,345,518	524.8	0.0	31	0	813,945	0	718	34,095,179
Jan-12	33,953,549	631.7	0.0	31	0	804,848	0	712	35,069,702
Feb-12	30,344,156	550.5	0.0	29	0	795,751	0	710	31,886,214
Mar-12	28,753,454	351.4	0.2	31	1	786,654	0	703	29,175,353
Apr-12	26,394,365	335.9	0.0	30	1	777,558	0	705	28,035,916
May-12	27,582,029	89.4	26.5	31	1	768,461	0	710	28,389,182
Jun-12	30,181,641	32.4	74.8	30	0	759,364	1	717	30,877,101
Jul-12	37,000,778	0.0	160.2	31	0	750,267	1	722	37,778,465
Aug-12	32,929,454	8.4	72.0	31	0	741,171	1	725	31,913,011
Sep-12	28,295,171	101.8	26.4	30	1	732,074	0	727	28,407,854
Oct-12	28,553,832	243.0	0.6	31	1	722,977	0	725	29,209,600
Nov-12	31,003,876	433.9	0.0	30	1	713,880	0	715	29,857,743
Dec-12	33,121,686	436.4	0.0	31	0	704,784	0	713	33,179,619
Jan-13		732.5	0.0	31	0	711,722	0	713	36,541,907
Feb-13		647.8	0.0	28	0	718,661	0	713	32,316,665
Mar-13		541.6	0.0	31	1	725,600	0	713	32,005,880
Apr-13		329.3	0.3	30	1	732,538	0	713	28,494,885
May-13		165.5	12.9	31	1	739,477	0	713	28,552,994
Jun-13		35.1	55.2	30	0	746,416	1	713	29,395,324
Jul-13		5.5	107.3	31	0	753,354	1	713	33,717,402
Aug-13		11.1	78.7	31	0	760,293	1	713	31,777,427
Sep-13		71.7	22.3	30	1	767,232	0	713	26,968,245
Oct-13		261.1	2.1	31	1	774,170	0	713	28,788,503
Nov-13		407.7	0.0	30	1	781,109	0	713	29,216,629
Dec-13		600.2	0.0	31	0	788,048	0	713	34,782,530
Jan-14		732.5	0.0	31	0	777,897	0	713	36,328,256
Feb-14		647.8	0.0	28	0	767,747	0	713	32,158,188
Mar-14		541.6	0.0	31	1	757,597	0	713	31,902,576
Apr-14		329.3	0.3	30	1	747,446	0	713	28,446,754
May-14		165.5	12.9	31	1	737,296	0	713	28,560,036
Jun-14		35.1	55.2	30	0	727,146	1	713	29,457,539
Jul-14		5.5	107.3	31	0	716,995	1	713	33,834,790
Aug-14		11.1	78.7	31	0	706,845	1	713	31,949,988
Sep-14		71.7	22.3	30	1	696,694	0	713	27,195,979
Oct-14		261.1	2.1	31	1	686,544	0	713	29,071,411
Nov-14		407.7	0.0	30	1	676,394	0	713	29,554,710
Dec-14		600.2	0.0	31	0	666,243	0	713	35,175,784
									4,515,961,383
2003	377,328,535								381,192,539
2004	382,256,439								379,747,959
2005	397,949,707								395,951,547
2006	378,534,757								378,548,927
2007	385,126,910								383,078,976
2008	376,481,614								380,253,618
2009	357,880,923								356,784,936
2010	371,940,959								365,011,314
2011	374,153,149								375,417,407
2012	368,113,990								373,779,761
2013									372,558,390
2014									373,636,010
Total to 2012	3,769,766,983								3,769,766,983
									4,515,961,383

APPENDIX B
Monthly Heating & Cooling Degree Days

10-Year Average (2003 to 2012)

Heating Degree Days	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	10 Year Average
January	829.5	859.1	765.8	554.7	665.6	633.6	852.3	728.7	804.3	631.7	**732.5**
February	699.2	647.7	641.7	602.8	761.8	678.8	616.6	618.4	660.1	550.5	**647.8**
March	593.1	513.6	646.9	530.4	565.2	620.7	540.9	456.8	596.7	351.4	**541.6**
April	387.1	329.3	339.0	314.6	374.2	288.1	334.7	235.8	354.0	335.9	**329.3**
May	215.8	164.1	212.7	155.5	138.4	214.1	178.1	128.4	158.6	89.4	**165.5**
June	54.5	60.1	13.1	26.7	19.2	34.2	58.5	27.2	25.0	32.4	**35.1**
July	6.5	7.7	1.1	1.9	9.2	3.7	18.9	5.7	0.0	0.0	**5.5**
August	5.7	28.9	3.8	8.1	8.4	20.2	18.1	6.9	2.4	8.4	**11.1**
September	73.9	43.9	32.8	105.3	55.2	70.5	67.9	97.2	68.7	101.8	**71.7**
October	293.5	253.5	234.2	304.1	157.8	297.5	310.4	260.8	256.0	243.0	**261.1**
November	391.5	396.0	396.3	393.1	467.5	460.6	371.7	416.7	349.2	433.9	**407.7**
December	571.0	636.7	688.8	508.1	641.0	655.3	643.6	695.9	524.8	436.4	**600.2**
Total	4,121.3	3,940.6	3,976.2	3,505.3	3,863.5	3,977.3	4,011.7	3,678.5	3,799.8	3,214.8	**3,808.9**

Cooling Degree Days	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	10 Year Average
January	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
February	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
March	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	**0.0**
April	0.0	0.0	0.0	0.0	0.0	0.0	1.7	0.8	0.0	0.0	**0.3**
May	0.0	14.2	0.0	22.4	23.3	0.3	0.0	28.8	13.3	26.5	**12.9**
June	41.4	29.2	119.6	43.2	74.2	55.0	30.2	44.8	40.0	74.8	**55.2**
July	83.9	71.6	144.7	136.1	82.0	87.7	21.7	121.6	163.7	160.2	**107.3**
August	102.6	40.0	102.5	70.1	106.0	45.2	69.7	95.6	83.2	72.0	**78.7**
September	14.8	31.2	25.6	4.1	37.2	19.8	13.3	24.2	26.8	26.4	**22.3**
October	0.0	0.0	7.6	0.0	13.0	0.0	0.0	0.0	0.0	0.6	**2.1**
November	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
December	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
Total	242.7	186.2	400.0	275.9	335.7	208.0	136.6	315.8	327.0	360.7	**278.9**

20-Year Trend (1993 to 2012)

Heating Degree Days	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	20 Year Trend
January	672.3	920.4	643.1	774.2	746.1	620.8	774.6	747.9	703.0	592.6	829.5	859.1	765.8	554.7	665.6	633.6	852.3	728.7	804.3	631.7	**708.5**
February	729.1	747.1	709.5	699.4	573.8	520.3	556.8	622.7	597.3	553.9	699.2	647.7	641.7	602.8	761.8	678.8	616.6	618.4	660.1	550.5	**611.1**
March	640.8	595.8	499.0	666.6	583.1	504.6	566.8	434.7	598.5	539.3	593.1	513.6	646.9	530.4	565.2	620.7	540.9	456.8	596.7	351.4	**498.8**
April	355.3	333.9	422.7	408.3	375.1	290.7	317.5	363.5	314.1	338.9	387.1	329.3	339.0	314.6	374.2	288.1	334.7	235.8	354.0	335.9	**305.7**
May	186.0	212.6	165.4	210.1	269.6	82.1	113.1	151.7	142.2	248.9	215.8	164.1	212.7	155.5	138.4	214.1	178.1	128.4	158.6	89.4	**144.2**
June	54.3	42.8	21.7	26.5	33.3	63.3	37.5	42.8	40.9	41.9	54.5	60.1	13.1	26.7	19.2	34.2	58.5	27.2	25.0	32.4	**31.2**
July	1.7	3.6	13.4	12.0	14.5	1.3	1.0	12.2	17.9	0.9	6.5	7.7	1.1	1.9	9.2	3.7	18.9	5.7	0.0	0.0	**4.6**
August	8.6	29.0	4.1	2.2	23.1	5.3	12.7	18.0	0.7	4.2	5.7	28.9	3.8	8.1	8.4	20.2	18.1	6.9	2.4	8.4	**9.0**
September	148.1	91.9	121.0	85.4	89.5	51.8	71.0	115.3	93.3	32.8	73.9	43.9	32.8	105.3	55.2	70.5	67.9	97.2	68.7	101.8	**60.8**
October	321.9	251.4	223.7	272.4	270.0	234.9	282.5	230.8	243.5	304.1	293.5	253.5	234.2	304.1	157.8	297.5	310.4	260.8	256.0	243.0	**257.3**
November	449.7	375.0	516.7	521.0	485.1	402.7	377.2	447.4	332.1	449.5	391.5	396.0	396.3	393.1	467.5	460.6	371.7	416.7	349.2	433.9	**388.1**
December	624.2	569.6	713.3	570.8	596.9	539.5	588.5	811.6	535.2	643.2	571.0	636.7	688.8	508.1	641.0	655.3	643.6	695.9	524.8	436.4	**583.5**
Total	4,192.0	4,173.1	4,053.6	4,248.9	4,060.1	3,317.3	3,699.2	3,998.6	3,618.7	3,750.2	4,121.3	3,940.6	3,976.2	3,505.3	3,863.5	3,977.3	4,011.7	3,678.5	3,799.8	3,214.8	**3602.8**

Cooling Degree Days	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	20 Year Trend
January	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
February	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
March	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	**0.0**
April	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.0	0.0	0.0	0.0	0.0	0.0	0.0	1.7	0.8	0.0	0.0	**0.8**
May	2.9	7.5	0.6	10.7	0.0	29.2	13.6	18.7	8.3	8.3	0.0	14.2	0.0	22.4	23.3	0.3	0.0	28.8	13.3	26.5	**18.0**
June	28.7	66.5	75.3	32.7	61.8	79.2	86.3	38.6	63.7	64.7	41.4	29.2	119.6	43.2	74.2	55.0	30.2	44.8	40.0	74.8	**55.7**
July	111.4	95.0	124.9	56.3	72.1	74.0	163.7	57.7	79.6	151.0	83.9	71.6	144.7	136.1	82.0	87.7	21.7	121.6	163.7	160.2	**120.2**
August	101.1	43.2	123.9	78.1	37.2	100.7	47.0	58.3	114.0	94.4	102.6	40.0	102.5	70.1	106.0	45.2	69.7	95.6	83.2	72.0	**78.4**
September	12.3	10.6	12.9	22.5	6.7	41.4	38.5	30.1	21.8	61.3	14.8	31.2	25.6	4.1	37.2	19.8	13.3	24.2	26.8	26.4	**27.7**
October	0.7	0.0	0.2	0.0	3.9	0.0	0.0	0.2	0.0	8.9	0.0	0.0	7.6	0.0	13.0	0.0	0.0	0.0	0.0	0.6	**2.6**
November	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
December	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
Total	257.1	222.8	337.8	200.3	181.7	324.5	349.1	203.6	287.4	396.6	242.7	186.2	400.0	275.9	335.7	208.0	136.6	315.8	327.0	360.7	**303.3**

Exhibit 4 – Operating Costs			
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OVERVIEW OF OPERATING COSTS

Operating Costs

The operating costs presented in this Exhibit represent the annual expenditures required to sustain Haldimand County Hydro Inc.'s ("HCHI") electricity distribution operations. The Operating, Maintenance, and Administrative ("OM&A") costs in this Exhibit represent HCHI's integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives; to comply with the Distribution System Code, environmental requirements and government direction; to maintain electricity distribution business service quality and reliability at targeted performance levels; and to provide services to customers connected to HCHI's distribution system.

There has been considerable change in the electricity distribution sector since HCHI's last rebasing in 2010 including: (i) the implementation of Smart Meters; (ii) Time of Use ("TOU") pricing; (iii) mandated Conservation and Demand Management ("CDM") programs; (iv) requirements under the Green Energy Act ("GEA") Plan with respect to renewable generation; and (v) the implementation of revised depreciation and capitalization policies for regulatory accounting purposes. These government mandated requirements, which fall under "Public Policy Responsiveness" as part of the Ontario Energy Board's (the "Board's) Renewed Regulatory Framework for Electricity Distributors ("RRFE"), have translated into incremental OM&A expenditures for HCHI since its last rebasing.

In addition to increases in OM&A expenditures as a result of government mandated requirements, HCHI has experienced increases in OM&A expenditures attributable to: (i) salaries and wages which have increased by approximately 3% per year; (ii) increases in the employee complement to support the government mandated requirements, regulatory compliance, and capacity constraints in certain key departments; (iii) increased benefit costs for the current and forecasted employee

complement, and in particular significant increases in OMERs pension costs; and (iv) increases in information technology costs.

HCHI currently follows Canadian Generally Accepted Accounting Policies ("CGAAP") for accounting purposes and utilizes the Board's Accounting Procedures Handbook ("APH") in distinguishing work performed between operating and maintenance. HCHI has opted for the deferral of the mandatory adoption of International Financial Reporting Standards ("IFRS") until January 1, 2015. In accordance with the Board's letter of July 17, 2012, electricity distributors electing to remain on CGAAP must implement regulatory accounting changes for depreciation expense and capitalization policies by January 1, 2013. Effective January 1, 2013, HCHI revised its asset estimated useful lives under CGAAP in accordance with the regulatory accounting changes. This will be discussed in further detail in Tab 3, Schedule 3 of this Exhibit. HCHI did not make any changes to its capitalization policy, as all costs currently included in overhead rates are appropriate. HCHI has therefore not completed OEB Appendix 2-DB "Overhead" as no changes are required.

The OM&A expenditures proposed for the 2014 Test Year are the result of a business planning and work prioritization process that ensures that the most appropriate, cost effective solutions are put in place. HCHI's is proposing recovery of the 2014 Test Year OM&A costs, excluding depreciation, PILs, and interest totaling $8,706,492.

Operating Budget Process

The operating budget is prepared annually by Management and is reviewed and approved by the Board of Directors of HCHI. The budget is prepared before the start of each fiscal year. Once approved, it does not change, but provides a plan against which actual results may be evaluated. The 2013 Bridge Year forecast is based on the 2013 budget approved by HCHI's Board of Directors December 21, 2012, with adjustments to reflect actual year-to-date information where applicable. The development of the 2014 Test Year forecast followed a similar budget process, but was accelerated from the

normal approval date in the fourth quarter of 2013 to a final approval by HCHI's Board of Directors June 26, 2014 in conjunction with the filing of HCHI's 2014 COS rate Application.

The operating budget is a component of the overall budget process described in Exhibit 1, Tab 1, Schedule 3.

Operating Work plans

Each Department Manager provides input for the preparation of the departmental budget. The following directives are provided to each Manager:

- Expenses for all department budgets are built using previous year actual, current year budget and current year forecast as the base utilizing known increases where possible. For the 2013 and 2014 budgets, where increases are not known, an average inflationary increase in the order of 2% has been applied;
- Review operating priorities and requirements to identify resources, including labour, trucks, materials and other third party costs that are required to complete budgeted item;
- Significant variances in spending from prior years must be explained and documented;
- Review the staff complement of department for accuracy and forecast any changes as a result of future requirements;
- Balance labour hours distributed to various accounts to total available labour hours by employee within department;
- Overtime and account distribution are based on previous years actual, current year budget and current year forecast for all departments except Operations;
- Operations use a trending function (statistical function) method to estimate labour and truck hours allocated to accounts. This method uses actual data from 2003

to 2012 and trended values for 2013 and calculated values based on a linear trend line which best fits the known data; and

- Finance prepares a worksheet of hourly labour rates including payroll burden by job classification using projected wage and benefit costs per the Collective Agreement with the Union currently in place at time of budget preparation. The increases in the most recent Collective Agreement that impact the 2014 Test Year labour costs are 1.25% effective October 1, 2013, 1.50% effective April 1, 2014, and 1.25% effective October 1, 2014.

SUMMARY AND COST DRIVER TABLES

OM&A Summary of Costs

A summary of HCHI's operating, maintenance, and administrative costs for the 2010 Board Approved, 2010 Actual, 2011 Actual, 2012 Actual, 2013 Bridge Year and the 2014 Test Year, with annual percentage changes, is provided in Table 1 below. Table 2 represents the OM&A cost per customer and per full-time equivalent employee. This information is also filed as OEB Appendix 2-JA "OM&A Summary Analysis" and Appendix 2-L "OM&A per Customer FTEE", respectively.

Table 1
Summary of OM&A Expenses

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Operating	$ 1,418,231	$ 1,454,866	$ 1,669,077	$ 2,061,484	$ 1,901,712	$ 1,926,274
Maintenance	$ 2,693,492	$ 2,187,634	$ 2,459,521	$ 2,311,614	$ 2,802,176	$ 2,751,043
SubTotal	**$ 4,111,723**	**$ 3,642,500**	**$ 4,128,598**	**$ 4,373,098**	**$ 4,703,888**	**$ 4,677,317**
%Change (year over year)			13.3%	5.9%	7.6%	(0.6%)
%Change (Test Year vs Last Rebasing Year - Actual)						28.4%
Billing and Collecting	$ 1,319,423	$ 1,305,988	$ 1,154,952	$ 1,867,865	$ 1,565,594	$ 1,618,934
Community Relations	$ 46,836	$ 42,643	$ 45,426	$ 143,208	$ 64,620	$ 69,320
Administrative and General	$ 1,967,377	$ 1,883,392	$ 2,029,380	$ 2,037,455	$ 2,379,386	$ 2,340,921
SubTotal	**$ 3,333,636**	**$ 3,232,023**	**$ 3,229,758**	**$ 4,048,528**	**$ 4,009,600**	**$ 4,029,175**
%Change (year over year)			(0.1%)	25.4%	(1.0%)	0.5%
%Change (Test Year vs Last Rebasing Year - Actual)						24.7%
Total	**$ 7,445,359**	**$ 6,874,523**	**$ 7,358,356**	**$ 8,421,626**	**$ 8,713,488**	**$ 8,706,492**
%Change (year over year)			7.0%	14.4%	3.5%	(0.1%)

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Operating	$ 1,418,231	$ 1,454,866	$ 1,669,077	$ 2,061,484	$ 1,901,712	$ 1,926,274
Maintenance	$ 2,693,492	$ 2,187,634	$ 2,459,521	$ 2,311,614	$ 2,802,176	$ 2,751,043
Billing and Collecting	$ 1,319,423	$ 1,305,988	$ 1,154,952	$ 1,867,865	$ 1,565,594	$ 1,618,934
Community Relations	$ 46,836	$ 42,643	$ 45,426	$ 143,208	$ 64,620	$ 69,320
Administrative and General	$ 1,967,377	$ 1,883,392	$ 2,029,380	$ 2,037,455	$ 2,379,386	$ 2,340,921
Total	**$ 7,445,359**	**$ 6,874,523**	**$ 7,358,356**	**$ 8,421,626**	**$ 8,713,488**	**$ 8,706,492**
%Change (year over year)			7.0%	14.4%	3.5%	(0.1%)

Table 2
OM&A Cost per Customer and FTEE

	Last Rebasing Year - 2010-Board Approved	Last Rebasing Year - 2010-Actual	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Number of Customers	24,594	24,666	24,670	24,709	24,759	24,845
Total Recoverable OM&A	$ 7,445,359	$ 6,874,523	$ 7,358,356	$ 8,421,626	$ 8,713,488	$ 8,706,492
OM&A cost per customer	**$ 302.73**	**$ 278.70**	**$ 298.27**	**$ 340.83**	**$ 351.93**	**$ 350.43**
Number of FTEs	46	47	47	50	50	52
Customers/FTEs	535	525	525	494	495	478
OM&A Cost per FTE	**$ 161,855.63**	**$146,266.45**	**$156,560.77**	**$168,432.52**	**$174,269.76**	**$ 167,432.54**

Note – Table 2 Information

1. One Full-time position "Conservation Specialist" has not been included in the number of "FTEs" as it is a fully funded position by the Ontario Power Authority ("OPA") through the Conservation and Demand Management programs. This is consistent for the 2010 Board Approved, 2010 to 2012 Actuals, 2013 Bridge Year, and the 2014 Test Year.

OM&A expenditures in the 2014 Test Year of $8,706,492 represents an increase of $1,261,133 or 16.9% over the 2010 Board Approved OM&A expenditures of $7,445,359 and $1,831,969 or 26.6% over the 2010 Actual (last-rebasing year actual) of $6,874,523. The 2014 Test Year as compared to the 2012 actual represents an increase of $284,866 or 3.4%. The 2012 Actual includes $729,190 of smart meter related costs approved for disposition November 1, 2012 as part of HCHI's Smart Meter Cost Recovery Application (EB-2012-0272). Table 3 below provides details of the allocation of these smart meter costs to the appropriate years, with $154,614 of the $729,190 actually attributable to the 2009 year and reported in the 2012 Actual.

This reallocation of smart meter costs to the years in which the actual costs were incurred changes the percentage increases in OM&A to the 2014 Test Year. The 2010 Actual year (last rebasing year actual) now reported as $7,104,946 calculates an increase of $1,601,546 or 22.5% from the 2014 Test Year expenditures of $8,706,492.

The 2014 Test Year now compared to the 2012 Actual expenditures of $7,847,050 (after reallocation of smart meter costs) represents an increase of $859,442 or 10.9%. If the smart meter costs actually incurred in 2009 were backed out of the 2012 Actual, the expenditures for 2012 would be $7,692,436 which would result in an increase of $1,014,056 or 13.2% to the 2014 Test Year.

Table 3
Summary of OM&A Expenses
(Excluding Smart Meter Costs)

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Operating	$ 1,418,231	$ 1,454,866	$ 1,669,077	$ 2,061,484	$ 1,901,712	$ 1,926,274
Maintenance	$ 2,693,492	$ 2,187,634	$ 2,459,521	$ 2,311,614	$ 2,802,176	$ 2,751,043
Smart Meter Disposition Reallocation		$ 11,929	$ 78,655	$ (90,584)		
SubTotal	**$ 4,111,723**	**$ 3,654,429**	**$ 4,207,253**	**$ 4,282,514**	**$ 4,703,888**	**$ 4,677,317**
%Change (year over year)			15.1%	1.8%	9.8%	(0.6%)
%Change (Test Year vs Last Rebasing Year - Actual)						28.0%
Billing and Collecting	$ 1,319,423	$ 1,305,988	$ 1,154,952	$ 1,867,865	$ 1,565,594	$ 1,618,934
Community Relations	$ 46,836	$ 42,643	$ 45,426	$ 143,208	$ 64,620	$ 69,320
Administrative and General	$ 1,967,377	$ 1,883,392	$ 2,029,380	$ 2,037,455	$ 2,379,386	$ 2,340,921
Smart Meter Disposition Reallocation		$ 218,494	$ 265,498	$ (483,992)		
SubTotal	**$ 3,333,636**	**$ 3,450,517**	**$ 3,495,256**	**$ 3,564,536**	**$ 4,009,600**	**$ 4,029,175**
%Change (year over year)			1.3%	2.0%	12.5%	0.5%
%Change (Test Year vs Last Rebasing Year - Actual)						16.8%
Total	**$ 7,445,359**	**$ 7,104,946**	**$ 7,702,509**	**$ 7,847,050**	**$ 8,713,488**	**$ 8,706,492**
%Change (year over year)			8.4%	1.9%	11.0%	(0.1%)

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Operating	$ 1,418,231	$ 1,466,795	$ 1,747,732	$ 1,970,900	$ 1,901,712	$ 1,926,274
Maintenance	$ 2,693,492	$ 2,187,634	$ 2,459,521	$ 2,311,614	$ 2,802,176	$ 2,751,043
Billing and Collecting	$ 1,319,423	$ 1,512,741	$ 1,353,101	$ 1,462,963	$ 1,565,594	$ 1,618,934
Community Relations	$ 46,836	$ 42,643	$ 95,290	$ 93,344	$ 64,620	$ 69,320
Administrative and General	$ 1,967,377	$ 1,895,133	$ 2,046,865	$ 2,008,229	$ 2,379,386	$ 2,340,921
Total	**$ 7,445,359**	**$ 7,104,946**	**$ 7,702,509**	**$ 7,847,050**	**$ 8,713,488**	**$ 8,706,492**
%Change (year over year)			8.4%	1.9%	11.0%	(0.1%)

The Board's *Filing Requirements for Electricity Distribution Rate Applications*, dated July 17, 2013 (the "Filing Requirements") suggest a default materiality threshold for rate base, capital expenditures, OM&A and other items, and that it be determined based on a distributor's revenue requirement. HCHI's distribution revenue requirement falls into the category of greater than $10 million and less than or equal to $200 million; resulting in HCHI's materiality threshold calculated as 0.5% of its distribution revenue requirement. The calculation for the 2014 Test Year is summarized in Table 4 below.

Table 4
OM&A Materiality Threshold

	2014 Test Year
Distribution Revenue Requirement	12,874,552
	0.50%
Calculated Materiality Threshold	64,373
Materiality Threshold Used	**64,000**

HCHI has adopted a variance analysis threshold of $64,000. Detailed information with respect to OM&A costs and variances, arranged by OM&A programs, is provided at Tab 2, Schedules 2 and 3 of this Exhibit.

OM&A Cost Drivers

The following is a summary of the primary drivers that have influenced the increase in HCHI's OM&A expenditures since 2010, the date of HCHI's last COS rate application, up to and including the 2014 Test Year. Each cost driver is summarized by its net change year over year.

HCHI has provided a list of cost drivers in Table 5 that affect OM&A year over year including the 2010 Actual (last rebasing year), 2011 Actual, 2012 Actual, 2013 Bridge Year, and the 2014 Test Year with a combined total change from the 2010 Actual to the 2014 Test Year. The closing totals in Table 4 reconcile to the totals by year in Table 1 above. The cost driver information is also filed as OEB Appendix 2-JB "OM&A Cost Drivers".

Cost driver variances have been explained following Table 5 by the combined total change for those variances that meet the materiality threshold of $64,000 and/or represent a common or recurring expenditure that has impacted multiple years.

Table 5
OM&A Cost Drivers

OM&A Expenditures	Last Rebasing Year (2010 Board-Approved)	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year	Total Change
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	
Opening Balance	**$ 7,445,359**	**$ 6,874,523**	**$ 7,358,356**	**$ 8,421,626**	**$ 8,713,488**	**$ 7,445,359**
Labour and Net Benefit Changes	$ (478,244)	$ 156,192	$ 164,562	$ 292,146	$ 72,108	$ 206,764
Labour - New Positions	$ 40,120	$ 80,000	$ 114,000	$ 185,723	$ 192,940	$ 612,783
Smart Meter Disposition	$ -	$ -	$ 729,190	$ (729,190)	$ -	$ -
Year over Year Allocation between Capital Spend and Operations/Maintenance	$ (91,396)	$ 15,895	$ 68,458	$ (15,366)	$ 12,420	$ (9,989)
Connection Impact Assessments	$ (36,100)	$ 36,389	$ (19,980)	$ (9,660)	$ -	$ (29,351)
Embedded Distributor Costs	$ 90,082	$ 90,482	$ 8,919	$ (13,460)	$ 51,518	$ 227,541
Waste Disposal	$ (34,604)	$ 4,141	$ (10,033)	$ 29,342	$ -	$ (11,154)
Tree Trimming Services	$ (154,016)	$ (120,775)	$ 110,617	$ 277,507	$ (194,625)	$ (81,292)
Overhead Distribution Lines (Storm Activity)	$ (221,221)	$ 58,492	$ (97,982)	$ 124,067	$ 5,042	$ (131,602)
Distribution Transformers (PCB Removals)	$ 35,949	$ 78,368	$ 66,242	$ (62,292)	$ (3,289)	$ 114,978
Third Party Contractor Work (PCB Transformer Testing; Meter Costs; Grass & Snow Removal; U/G Plant Inspection; Line Contractor)	$ 206,295	$ 229,990	$ (95,859)	$ (241,346)	$ (15,426)	$ 83,654
Locates (One Call Fee; Internal vs. External Labour)	$ -	$ -	$ -	$ 28,112	$ (105,644)	$ (77,532)
Apprenticeship Tax Credit	$ -	$ -	$ (13,490)	$ 13,490	$ -	$ -
Billing / Collection Costs (Postage; Outsourced mailing; Initial Calls; Collections Field Work; Employee Training)	$ (29,513)	$ (39,959)	$ 45,449	$ (4,629)	$ (7,051)	$ (35,703)
Meter Reading Costs (includes Retail Services for Interval meter interrogations)	$ 60,071	$ (132,651)	$ 75,533	$ 95,060	$ 5,613	$ 103,626
Bad Debt Expense	$ 9,405	$ 17,625	$ 6,443	$ 10,538	$ 20,038	$ 64,049
Services - Admin Fees (RESOP Generators)	$ (6,048)	$ -	$ (6,829)	$ 13,079	$ -	$ 202
Christmas Light Work and Banners	$ (8,535)	$ 2,783	$ -	$ -	$ 4,700	$ (1,052)
Customer Communications	$ 4,342	$ -	$ 14,956	$ 4,239	$ -	$ 23,537
Administrative Costs (Employee training; Liability Insurance; Property Taxes; Property Insurance)	$ -	$ (19,647)	$ (7,937)	$ 59,038	$ 48,814	$ 80,268
Outside Services (Consultant costs; Auditing & Legal Fees)	$ (147,260)	$ 150,990	$ (23,129)	$ 227,244	$ (155,701)	$ 52,144
Special Purpose Charge	$ 94,692	$ (48,175)	$ (46,187)	$ -	$ -	$ 330
Late Payment Class Action Settlement	$ 52,100	$ -	$ -	$ -	$ -	$ 52,100
LEAP Funding	$ -	$ 16,500	$ -	$ -	$ -	$ 16,500
Regulatory Costs (Cost Awards; Notice of Applications; OEB Fixed Cost Assessments)	$ 46,361	$ (87,147)	$ (25,140)	$ 15,496	$ 61,367	$ 10,937
Miscellaneous	$ (3,316)	$ (5,660)	$ 5,467	$ (7,276)	$ 180	$ (10,605)
Closing Balance	**$ 6,874,523**	**$ 7,358,356**	**$ 8,421,626**	**$ 8,713,488**	**$ 8,706,492**	**$ 8,706,492**

Labour and Net Benefit Changes:

HCHI's labour and net benefit changes are a combination of unionized wage increases per the Collective Agreement in place for each of the years, the non-unionized pay increases per the Policy Manual for Non-Unionized Staff approved by HCHI's Board of Directors, and the annual increases to associated benefits.

HCHI's Collective Agreement with unionized staff provides for periodic payroll increases and employee step progressions. Labour rates are adjusted throughout the year based on negotiated percentages contained within the Collective Agreement. HCHI's current Collective Agreement was negotiated during 2013 for a 4-year period commencing April 1, 2013 to March 31, 2017. The non-unionized pay increases follow the same format as the unionized with scheduled bi-annual payroll increases and employee step progressions. The Policy Manual for Non-Unionized Staff typically follows the same percentage increases as the Collective Agreement with the same renewal period expiring on March 31, 2017 but is subject to approval by HCHI's Board of Directors. The related associated benefits including: OMERs contributions; group insurance benefits such as health, dental, long-term disability and life insurance; statutory employer benefit contributions including CPP, EI, EHT, and WSIB; have increased annually as a result of increases in rates, labour dollar increases, and the increase in the number of full-time employees over the period.

Labour – New Positions:

Since 2010, HCHI has made an investment in people to address: (i) the significant regulated changes that have occurred in the electricity industry over the past four years, including the implementation of Smart Meters, Time of Use pricing, mandated CDM programs, and requirements under the GEA with respect to renewable generation; and (ii) capacity constraints in certain key departments, in particular, Engineering and Operations, whereby staffing levels were not sufficient to support the capital renewal

program and overall growth in capital expenditure program, and the regulatory requirements.

Between 2010 and 2013, HCHI has hired four new positions with plans to add one more position by the end of 2013 and one more position in 2014. These positions have been added in all departments including, Finance, Customer Service, Engineering, Metering, and Operations. It is important to note that not all of these positions translate to a 100% increase in OM&A expenditures as some costs of certain positions are allocated to capital and billable recoverable work.

Additional information on compensation and employee complement has been provided in this Exhibit at Tab 2, Schedule 4.

Embedded Distributor Costs:

A portion of the cost of servicing the Embedded Distributor – Hydro One Networks Inc. ("HONI") is allocated to an OM&A account. These costs are the sub-transmission rates charged to HCHI by HONI for 7 of the 8 metering points embedded to HCHI. In 2010 when this rate class was established, HCHI calculated a wheeling rate which included these costs. As an oversight, HCHI did not include these costs in its Board Approved OM&A which accounts for the positive cost driver from the 2010 Board Approved to the 2010 Actual. The total year over year change impact is a positive number as a result of the increase in HONI's sub-transmission rates over the four year period.

Tree Trimming Services:

The year over year change for tree trimming services has resulted in an overall decrease for the four year period. HCHI has a five year tree trimming cycle with variable costs in each year depending upon which area of the County is scheduled for trimming. This causes an expenditure variation from year to year depending upon the size of the geographical area, including whether it is urban versus rural, to be cleared in each of the five years. In some years, depending upon the area scheduled to be

completed, the tree trimming contractor may not be able to complete all anticipated clearing in the area and it will be carried over to the following year to be completed.

Overhead Distribution Lines – Storm Activity:

Within the four year period, HCHI has experienced a series of significant weather related impacts to the distribution system which required extensive emergency repairs. Storm related repairs are difficult to predict but are forecast based on historical averages. HCHI has experienced severe wind storms that can occur at any time of the year, damaging winter storms (ice, snow, hail, wind), and widespread electrical storms.

Distribution Transformers – PCB Removals:

HCHI has made a concerted effort to removed PCB transformers from its distribution system over the four year period, specifically in the 2011 and 2012 years. This expense is not expected to reoccur in 2014 and future years.

Third Party Contractor Work:

Over the four year period, HCHI has experienced an increase in third party contractor costs which occurred at the beginning of the four year period, between 2010 and 2011. Additional costs were incurred for PCB transformer testing, meter maintenance costs, grass and snow removal, underground plant inspections, and line contractors. As HCHI moves through this four year period, the third party contractor costs start to decrease in the OM&A expenditures as the line contractor costs are assigned to specific capital projects. As mentioned in the “Labour – New Positions” cost driver, the addition of new staff is required due to capacity constraints specifically with the overall growth in the capital expenditure program. HCHI should continue to see a decline in these third party contractor costs.

Locates:

HCHI will experience an overall decrease in locates as a result of the new position to be hired by the end of 2013 in the Metering department. After a period of training for this new position, they will perform the cable locating work previously performed by a third party contractor. This overall reduction is offset by the addition of the legislated Ontario One Call fees. In June 2012, Bill 8 "*Ontario Underground Infrastructure Notification System Act 2012*" became a law and all utilities with underground plant had to be registered by June 2013 with Ontario One Call and pay the appropriate fees.

Meter Reading Costs:

The overall four year change due to meter reading is on account of the change in the meter reading method within the new smart meter environment. HCHI incurs monthly service fees for four base stations and the per meter cost from the Operational Data Store. Manual meter reading is still performed for the General Service 50 to 4999 kW customers without an interval meter. An additional cost that HCHI has experienced over the four year period is on account of the number of retail meter interrogations due to the number of distribution-connected generators in HCHI's service territory.

Bad Debt Expense:

Bad debt expense represents the amount of accounts receivable that are considered uncollectible in a given period. The amount of bad debt expense is determined as the amount of customer accounts written off as uncollectible, less amounts recovered, plus or minus a change in the allowance for doubtful accounts. The allowance for doubtful accounts is calculated based on amounts that are outstanding beyond 90 days, plus a general provision on the balance of outstanding accounts receivable. HCHI also includes in the bad debt expense any miscellaneous accounts receivable ("MAR") on account of recoverable work billed by HCHI, including for damages to HCHI's distribution system that HCHI deems uncollectible.

The bad debt expense has increased due to the number of customer accounts in excess of 90 days past due increasing which has caused an increase in HCHI's allowance for doubtful accounts. HCHI has also forecast to write-off a large MAR from 2010 where all efforts have been exhausted for collection of this MAR on account of an out-of-province debtor.

Administrative Costs:

HCHI has included additional training in its 2013 Bridge Year and 2014 Test Year for administrative staff for various types of software to assist with reporting and extraction of data from its financial software. Training courses have also been forecast for the newer staff members in order to train on all aspects of the financial software. HCHI has also experienced inflationary increases in its insurance premiums and property taxes over the four year period.

One additional item contributing to the overall increase is the reduction of transformer credits forecast in 2013 and 2014. These credits received in the past are on account of rebates given by HCHI's transformer supplier for refurbished transformers. HCHI is unable to forecast how many transformers each year will be sent back for refurbishment and entitled to the rebate.

DEPARTMENTAL AND CORPORATE OM&A ACTIVITIES

OPERATIONS & MAINTENANCE

The expenses for this department include all costs relating to the operating (accounts 5000-5095) and maintenance (accounts 5105-5195) of the HCHI distribution system. This includes both direct and indirect labor costs, rolling stock, building and maintenance overheads and non-capital material spending to support both scheduled and reactive maintenance events.

HCHI's maintenance strategy is, to the extent possible, to minimize reactive and emergency-type work through an effective planned maintenance program (including predictive and preventative actions).

HCHI's customer responsiveness and system reliability are monitored continually to ensure that its maintenance strategy is effective. This effort is coordinated with HCHI's capital project work, so that where maintenance programs have identified matters, the correction for which require capital investments, HCHI may adjust its capital spending priorities to address those matters.

Predictive Maintenance

Predictive maintenance activities involve the testing of elements of the HCHI distribution system. These activities include infrared thermography testing, substation transformer oil analysis, planned visual inspections and pole testing. These evaluation tools are all administered using a grid system with appropriate frequency levels. Any identified deficiencies found are prioritized and addressed within a suitable time frame.

Preventative Maintenance

Preventative maintenance activities include annual tree and line clearing activities, inspection, servicing and repair of network components. This includes substation

maintenance, overhead and pad-mounted load break switch maintenance, hydraulic recloser maintenance, and regulator maintenance. The work is performed using a combination of time and condition based methodologies.

Emergency Maintenance

This item includes unexpected system repairs to the electrical distribution system that must be addressed immediately. The costs include those related to repairs caused by storm damage, defective equipment, emergency tree trimming and on-call premiums. HCHI constantly evaluates its maintenance data to adjust predictive and preventative actions. The ultimate objective is to reduce this emergency maintenance.

Service Work

The majority of costs related to this work pertain to service upgrades requested by customers. This includes service disconnections and reconnections by HCHI for all customer classes, assisting pre-approved contractors, the making of final connections after Electrical Safety Authority ("ESA") inspection for service upgrades, and changes of service locations.

Network Control Operations

Network operating costs are related to the 24-hour monitoring of customer emergency calls. An answering service company has been contracted to contact an "on call" lineperson and supervisory staff in the event of service problems after normal business hours. The Lines Department continuously monitors the system and dispatches repair crews to manage equipment failures and provide work protection for the crews doing work on the distribution system.

Metering

The Metering group, part of the Engineering Department, is responsible for the installation, testing, and commissioning of new and existing simple and complex metering installations. Testing of complex metering installations ensures the accuracy of the installation and verifies meter multipliers for billing purposes.

Revenue protection is another key activity performed by Metering, by proactively investigating potential diversion and theft of power.

The Engineering Department also provides underground locate services to anyone requesting verification of underground cable locations. This service has been provided through the use of a third party contractor t up to and including the 2013 Bridge Year. Commencing with the 2014 Test Year, HCHI will be providing these services utilizing internal metering staff.

Substation Services

Substation services activities address the maintenance of all equipment at HCHI's 5 energized substations and 1 voltage regulator station. Service activities on the in-service substations include both labour costs and non-capital material spending to support both scheduled and emergency maintenance events. To a large extent, costs for substation service activities are provided by third party contractors specializing in this type of work. As with other maintenance activities, HCHI's substation maintenance strategy focuses on minimizing, to the extent possible, emergency-type work by improving the effectiveness of HCHI's planned maintenance program (including predictive and preventative actions) for its substations.

ENGINEERING DEPARTMENT

Engineering is responsible for keeping asset related data up to date using Geographical Information System ("GIS") databases. The GIS system contains information on the majority of HCHI's major asset categories and generates reports for asset management activities. Distribution system inspection records are also contained within the GIS databases. The system contains a connectivity model and is currently integrated with Distribution Analysis software. It provides up to date distribution system operating maps for the Operations and Engineering departments and design drawings for construction activities including new capital projects and customer connections. Further work is required to develop the GIS system to improve project estimating and development of project material lists for construction projects. Future plans include integration with HCHI's Customer Information System ("CIS"), the financial reporting system ("Great Plains"), the Automated Metering Infrastructure ("AMI") and Operational Data Store ("ODS") to maximize the use of the data in each of those systems. Integration with the AMI will also provide information for power restoration efforts. It is also the intention of HCHI to integrate all of these systems to an Outage Management System ("OMS").

Engineering is responsible for the design for all aspects of the distribution system, including load and generation connections. The Engineering Technicians design service layouts and new distribution lines. The department is responsible for the safe design of the distribution system using current standards and regulations, and the design of protection and control schemes. For example, fuse coordination and automatic recloser settings.

STORES/WAREHOUSE

Stores staff is accountable for managing the replenishment, control, and movement of materials within HCHI's service centre. This would include monitoring inventory levels, material receipts, issues, and returns as required. The cost of the stores

department is allocated to all departments and capital as an overhead cost based on direct labour costs. A standard overhead percentage is set at the beginning of the year and adjusted to actual at year end.

GARAGE / TRANSPORTATION FLEET

The Operations and Engineering Departments support the inspection, maintenance and control of 18 fleet vehicles, including 8 large trucks (i.e. buckets) and 10 small vehicles (i.e. pickups / vans), including vehicle reliability and safety, and the minimization of vehicle down time. Vehicle costs are allocated to all departments and capital based on the actual number of truck hours applicable to each OM&A or capital job at an approved rate per hour. A standard cost per hour is set for all vehicles within the fleet – one rate for large trucks and one rate for small vehicles. Costs are adjusted to actual at year end and the hourly rates are reviewed annually for the following fiscal year.

SERVICE CENTRE

Costs collected in this area are for the operation and maintenance of the service centre, such as repairs to the service centre, landscape maintenance, building maintenance supplies, and security monitoring. Costs are allocated to all departments and capital as an overhead cost based on direct labour hours. A standard overhead percentage is set at the beginning of the year and adjusted to actual at year end.

LABOUR BURDEN / HEALTH AND SAFETY

The cost of all employee benefits and payroll taxes such as EI, CPP, EHT, WSIB, and group insurances are allocated to all departments and capital jobs based on direct labour hours. An overhead rate is set at the beginning of each year and adjusted to actual at year end.

The cost of health and safety is included in this burden allocation. Costs include health and safety program supplies and fees, and outside service costs associated with safety meetings. HCHI is committed to maximizing productivity and reducing risk of injury by initiating and implementing health and safety measures that focus on proactive actions. The commitment to health and safety is significant, and involves documenting meeting content and unsafe behaviors, safety training, monitoring conformance to established standards and policies, determining the effectiveness of safety training, implementation of a Risk Analysis Program, and monitoring the resolution of safety recommendations / audits, a commitment to continuous improvement in health and safety, and identifying and correcting root causes for system deficiencies. HCHI is pursuing Certificate Of Recognition ("COR") certification through the Infrastructure Health and Safety Association and has also completed a voluntary Work well-style audit with a third party auditor.

CUSTOMER SERVICE

The Customer Service Department is responsible for the customer care activities for approximately 21,300 customers and one Embedded Distributor in HCHI's service territory. These activities include meter reading, billing, call centre, collections, and other back office functions. The costs associated with the Customer Service department are accumulated in accounts 5305 to 5515.

Meter Reading

With the implementation of smart meters, the meter reading function is automated through the AMI network for the majority of customers, including the Residential and General Service Less Than 50 kW customer classes, totaling approximately 21,000 electric smart meters per month. In addition to the smart meters, the AMI network consists of four tower base stations and the ODS. Meter reading services for the approximately 90 smart meters installed on the General Service 50 to 4,999 kW (non-interval) customers are still contracted out to a non-affiliated third party under a service contract agreement. The smart meters with demand are unable to be processed with the Independent Electricity System Operator ("IESO") meter data management repository ("MDM/R").

Billing

HCHI bills on a monthly cycle, rendering approximately 256,000 invoices annually to customers. This total includes 2,600 final bills on average for customers moving within or outside of HCHI's service territory. An annual billing schedule is created based on the monthly meter reading schedule to ensure the timely billing of services. The billing functions include the VEE (verification, estimation and edit) processes, EBT (electronic billing transactions) and retailer settlement functions for approximately 1,990 retailer-enrolled accounts; coordination of billing information with the IESO MDM/R and the ODS; and account adjustments, meter changes, and

other various account related field service orders and mailing services. HCHI offers customers a number of payment options including an equal payment plan, electronic payment, and a preauthorized payment plan.

Collections

Collections involve a combination of activities, including the collection of overdue active accounts, security deposits and final bills for service termination. Credit risk is a concern for HCHI with 2014 Test Year credit loss forecast at $94,000 which is based on HCHI's historical write-offs of uncollectible accounts. Consistent with prior years, HCHI attempts to maintain the allowance for doubtful accounts equal to the amount of aged arrears 90 days and older. HCHI's 2014 credit loss forecast also includes an amount for unrecoverable MARs. In an effort to minimize credit losses, HCHI enforces a prudent credit policy in accordance with the Distribution System Code ("DSC") Active overdue accounts are collected by in-house staff through notices and direct telephone contact. Final bill collections are also collected by in-house staff through notices. Final accounts that remain unpaid 30 days after the final due date are turned over to a collection agency.

Customer Contact

The Customer Service Department is also responsible for such activities as payment processing, move in and out requests, and call centre. Average call volumes continue to increase annually. HCHI's Customer Service staff handles over 35,000 inquiries per year which is a combination of telephone and written requests.

Community Relations

HCHI is committed to providing consumer information and responses, in a timely and proactive manner, on electricity distribution and related issues. HCHI staff are available to answer customer questions in a friendly environment.

Since LDCs are typically the "face-to-the-customer" for the electricity industry, HCHI has an important role to play in educating the public about electrical safety and energy conservation.

Education – Electrical Safety

HCHI supports elementary schools in Haldimand County by providing electrical safety and conservation sessions for students in two age groups – JK to grade three and grades four to eight. These highly interactive sessions educate children in the dangers of electricity. HCHI also uses their website (www.haldimandcountyhydro.ca) to promote electrical safety and energy conservation.

Education – Energy Conservation

Building an energy conservation culture in Haldimand County continues to be an important objective for HCHI. HCHI remains very active in the community promoting Conservation and Demand Management ("CDM") initiatives with site visits for business customers and by attending a number of community events each year. Effective in 2011, as a condition of its distribution licence, HCHI is mandated by the OEB to deliver CDM to its customers and meet energy and demand savings targets by 2014. As a result, HCHI promotes and administers all applicable saveONenergy programs developed by the Ontario Power Authority ("OPA") directed at residential, commercial, industrial, and low-income customers.

ADMINISTRATIVE AND GENERAL EXPENSES

Administrative and general expenses include expenses incurred in connection with the general administration of the utility's operations. Within HCHI, the following functional areas are considered to be part of general administration and, as such, all expenses incurred within these functional areas are accounted for as administrative and general expenses:

- Board of Directors (i.e. Executive) (account 5605);
- Management (account 5610);
- Administrative, Finance and Regulatory Services (account 5615); and
- Information Technology Services (account 5615).

Board of Directors (Executive) Salaries and Expenses: 5605

The Board of Directors oversees and approves the operational plans for the organization. Expenses include salaries and all related expenses associated with the Board of Directors for HCHI.

Management Salaries and Expenses: 5610

Under the direction of the Board of Directors, the President & CEO is responsible for all aspects of HCHI. Also included in this category are the Department Managers, including Consumer Services, Engineering, Finance and Operations. Expenses include salaries and all related expenses for the employees within the above noted job classifications.

Administrative, Finance, and Regulatory Salaries and Expenses: 5615

Administrative Services

Included in this category is the Executive Assistant to the President & CEO who also provides support to the Department Managers and to the Board of Directors. Expenses include salary and all related expenses for this individual.

Financial Services

The Finance Department is responsible for the preparation of government statutory, Management and Board of Directors financial reporting in accordance with CGAAP; all daily accounting functions, including accounts payable, accounts receivable, and general accounting; treasury functions including cash management, risk management, accounting systems and internal control processes; preparation of consolidated budgets and forecasts; and supporting tax compliance. Expenses include salaries and all related expenses associated with the Accounting Supervisor, three Financial Analysts, and the Accounting Clerk.

Regulatory Services

The Regulatory Services are performed within the Finance Department by the Finance Manager with assistance from the Accounting Supervisor. They are responsible for all regulatory reporting and compliance with applicable codes and legislation governing HCHI. Regulatory reporting includes development and preparation of rate filings, performance reporting, and compliance.

Information Technology Salaries and Expenses: 5615

The Information Technology ("IT") staff are responsible for the development, operation, maintenance and security of all business system applications utilized by the utility in its operations. These include the customer information, financial reporting and work management systems. Expenses include salaries and all related costs associated with

the IT Technician. This position reports to the Systems Supervisor in the Customer Service Department. In addition, one third of the salary related costs associated with the Systems Supervisor are included in this account.

Office Supplies and Expenses: 5620

HCHI records general administration expenses which are not clearly applicable to any departmental group of operating expenses to this account. The expenses are further subdivided by the appropriate type of expense.

Outside Services Employed: 5630

Outside services employed include, but are not limited to, consulting and professional fees of external auditors, legal services, labour relations specialists, safety consultants, and rates consultants. Also included are expenses for outside computer labour and materials and the costs associated with the computer internet service provider.

Regulatory Expenses: 5655

Regulatory expenses include those expenses incurred in connection with Decisions and Orders on Cost Awards for hearings, proceedings, technical sessions, and other matters before the OEB or other regulatory bodies. Annual assessment fees paid to regulatory bodies are included in this expenditure category, which include fixed costs assessed by the OEB and the annual regulatory oversight cost recovery fee assessed by the Electrical Safety Authority ("ESA").

Miscellaneous General Expense: 5665

Miscellaneous General Expense includes expenditures for freight charges on inventory items and the costs of conductor reel deposits.

Electrical Safety Authority Fees: 5680

Expenses under Electrical Safety Authority ("ESA") fees include charges paid to the ESA for permits and inspections.

OM&A COSTS BY PROGRAM / MAJOR FUNCTION

Table 6, taken from OEB Appendix 2-JC "OM&A Programs", identifies HCHI's OM&A costs by program / major function from the 2010 Board Approved through to the 2014 Test Year. Material variances are highlighted in the table.

Table 6
Detailed, Account by Account, OM&A Expenses

OM&A Programs / Major Function	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year	Variance (Test Year vs. 2012 Actuals)	Variance (Test Year vs. Last Rebasing Year (2010 Board-Approved)
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
OPERATING PROGRAMS								
Supervision and Engineering	499,249	468,918	556,881	630,949	642,981	670,136	39,187	170,887
Distribution Station Equipment	37,459	38,231	33,984	32,931	47,850	53,255	20,324	15,796
Overhead Distribution Lines	100,588	140,891	171,849	145,027	136,100	140,772	(4,255)	40,184
Miscellaneous Distribution Expenses	192,883	159,966	185,803	160,535	211,280	211,537	51,002	18,654
HONI Sub-transmission Charges Re: Servicing Embedded Distributor		90,082	180,564	189,483	176,023	227,541	38,058	227,541
Underground Distribution Lines	58,608	80,920	75,942	90,536	109,798	90,243	(293)	31,635
Distribution Transformers	237,657	214,336	221,347	307,729	234,856	221,132	(86,597)	(16,525)
Distribution Meters	276,493	243,038	234,767	368,290	327,186	292,440	(75,850)	15,947
Distribution Meters - Smart Meter Disposition				119,128			(119,128)	-
Customer Premises	17,277	18,483	7,941	16,878	15,638	19,218	2,340	1,941
Sub-Total	1,420,214	1,454,865	1,669,078	2,061,486	1,901,712	1,926,274	**(135,212)**	**506,060**
MAINTENANCE PROGRAMS								
Supervision and Engineering	129,706	129,856	127,417	125,697	134,079	145,626	19,929	15,920
Distribution Station Equipment	107,029	108,052	237,157	30,937	22,985	63,263	32,326	(43,766)
Overhead Distribution Lines Re: Poles, Conductor, Services	1,647,046	1,208,142	1,448,564	1,309,477	1,551,713	1,695,097	385,620	48,051
Overhead Distribution Lines Re: Tree Trimming	466,696	312,680	191,906	302,523	580,030	385,405	82,882	(81,291)
Underground Distribution Lines	155,391	185,007	154,826	251,655	245,772	190,204	(61,451)	34,813
Distribution Transformers	159,370	231,182	275,482	268,808	250,996	245,934	(22,874)	86,564
Distribution Meters	26,272	12,715	24,169	22,515	16,601	25,514	2,999	(758)
Sub-Total	2,691,510	2,187,634	2,459,521	2,311,612	2,802,176	2,751,043	**439,431**	**59,533**
COMMUNITY RELATIONS PROGRAMS								
General	5,450	7,172	8,112	28,576	44,720	44,720	16,144	39,270
Banners and Christmas Lights	23,386	14,851	20,381	15,411	19,900	24,600	9,189	1,214
Energy Conservation	18,000	20,620	16,932	18,885	-	-	(18,885)	(18,000)
Energy Conservation - Smart Meter Disposition				80,336			(80,336)	-
Sub-Total	46,836	42,643	45,425	143,208	64,620	69,320	**(73,888)**	**22,484**
BILLING and COLLECTING PROGRAMS								
Supervision	144,980	142,674	143,307	150,888	168,245	179,361	28,473	34,381
Meter Reading	212,609	272,680	140,029	209,281	305,430	311,043	101,762	98,434
Meter Reading - Smart Meter Disposition				396,886			(396,886)	-
Customer Billing	602,980	528,227	523,653	631,037	670,627	690,893	59,856	87,913
Customer Billing - Smart Meter Disposition				102,097			(102,097)	-
Customer Collecting	254,886	258,458	225,155	248,698	260,578	251,812	3,114	(3,074)
Bad Debts	30,000	39,405	57,029	63,473	74,011	94,049	30,576	64,049
Retail Services	73,968	64,544	65,779	65,506	86,703	91,776	26,270	17,808
Sub-Total	1,319,423	1,305,988	1,154,952	1,867,866	1,565,594	1,618,934	**(248,932)**	**299,511**
ADMINISTRATIVE and GENERAL PROGRAMS								
Board of Director Expenses	71,428	48,832	57,207	102,865	130,364	83,421	(19,444)	11,993
Management, Administrative, IT Services	1,197,345	1,089,256	1,204,131	1,264,829	1,307,415	1,357,699	92,870	160,354
General Office Expenses	35,720	48,639	19,447	(18,820)	38,207	78,968	97,788	43,248
Membership Fees & Subscriptions	41,615	40,905	42,932	45,771	47,604	47,915	2,144	6,300
Professional Fees (Auditing, Legal, Consulting)	169,432	59,816	197,402	106,398	300,687	142,352	35,954	(27,080)
Professional Fees (Consulting) - Smart Meter Disposition				5,199			(5,199)	-
Professional Fees (Outside Computer Services)	232,674	195,029	208,435	276,309	309,264	311,898	35,589	79,224
Professional Fees (Outside Computer Services) - Smart Meter Disposition				24,027			(24,027)	-
Property and Liability Insurance	64,508	55,414	76,593	77,948	80,066	89,813	11,865	25,305
Property Insurance - Smart Meter Disposition				1,517			(1,517)	-
ESA and Regulatory Fees	101,208	199,669	112,523	87,382	102,878	164,245	76,863	63,037
Property Taxes	53,447	51,140	47,695	47,199	46,401	48,110	911	(5,337)
Special Purpose Charge	-	94,692	46,517	330	-	-	(330)	-
LEAP Funding	-	-	16,500	16,500	16,500	16,500	-	16,500
Sub-Total	1,967,377	1,883,392	2,029,382	2,037,454	2,379,386	2,340,921	**303,467**	**373,544**
Total	**7,445,359**	**6,874,522**	**7,358,358**	**8,421,626**	**8,713,488**	**8,706,492**	**284,866**	**1,261,132**

VARIANCE ANALYSIS ON OM&A COSTS

HCHI has provided a variance analysis between the 2010 Board Approved costs and the 2014 Test Year and between the 2012 actuals and the 2014 Test Year as per the Filing Requirements. Those costs exceeding the materiality threshold of $64,000 (refer to Table 4) have been highlighted in the above Table 6 with explanation to follow.

2014 Test Year versus 2010 Board Approved Variance Analysis

Operating Programs:

The variance of $170,887 in the Supervision and Engineering is on account of a new Distribution Engineer position added in 2012 to assist with the requirements under the GEA related to renewable energy generation. In addition, an Engineering Coop student has been included in the 2014 Test Year for one more work term than in the 2010 Board Approved. The remaining variance is on account of the annual scheduled wage increases.

The other material variance of $227,541 is attributed to the costs associated with servicing the Embedded Distributor – HONI. As discussed in Tab 1, Schedule 2 of this Exhibit, the costs recorded here are the sub-transmission rates charged to HCHI by HONI for 7 of the 8 metering points embedded to HCHI. As an oversight, HCHI did not include these costs in the 2010 Board Approved OM&A. An additional contributor to the increase is the increase in HONI's sub-transmission rates over the four year period.

Maintenance Programs:

Maintenance costs associated with tree trimming have decreased by $81,291 from the 2010 Board Approved to the 2014 Test Year. In HCHI's 2010 COS rate application, expenses relating to the specific area in Haldimand County required to be trimmed during that test year were included. A change in methodology was adopted for the 2014 Test Year to ensure the appropriate total 5 year revenue requirement is accounted for

but smoothed out over this five year period depending upon which cycle the COS rate application year occurs in. HCHI has a five year tree trimming cycle with variable costs in each year depending upon which area of the County is being trimmed. For the 2014 Test Year and purposes of rate-setting, the average tree trimming cost for the entire County has been determined, based upon two complete cycles performed to date, and divided by 5 to determine an "annualized average tree trimming cost".

Maintenance related to distribution transformers represents the other material variance of $86,564. The increase is due to additional repairs and maintenance related to aging transformers in HCHI's distribution system. The 2014 Test Year was forecast based on historical labour, truck, and material costs associated with this account.

Community Relations Programs:

No material variances.

Billing and Collecting Programs:

The variance of $98,434 in meter reading from the Board Approved to the 2014 Test Year is on account of the implementation of smart meters and a change in how electric meter data is collected, validated and stored.

An additional variance in these program costs of $87,913 is largely attributed to the addition of the new Sync Operator position in 2012. This position was added as part of the smart meter deployment to manage the smart meter data for the purposes of validating daily/hourly reads for billing as well as support for data integration points with the MDM/R, ODS, CIS and customer web portal/tools. A smaller contributor to the variance is represented by an increase in postal costs and training costs for Customer Service/Collection Representatives.

The remaining material variance of $64,049 is on account of an increase in bad debt expense in the 2014 Test Year from the 2010 Board Approved. The bad debt expense

has increased due to the number and magnitude of customer accounts in excess of 90 days past due increasing which has caused an increase in HCHI's allowance for doubtful accounts.

Administrative and General Programs:

Management, Administrative, and IT Services labour and general expenses have increased by $160,354 from the Board Approved amount in 2010 to the 2014 Test Year. This increase is a combination of the additional Financial Analyst position in the Finance department and the annual scheduled wage increases over the four year period.

The remaining material variance increase of $79,224 is attributed to outside services for computer labour related to monthly monitoring, AMI security audit, costs associated with the new smart meter environment, and the Harris Northstar CIS.

2014 Test Year versus 2012 Actual Variance Analysis

Operating Programs:

A decrease of $86,597 from the 2012 Actual to the 2014 Test Year is on account of the reduction in the number of PCB transformers being removed from HCHI's distribution system. The expense of removing PCB transformers from the distribution system is not expected to reoccur in 2014 and future years and has resulted in a reduction of transformer related costs.

An additional reduction in the operations program in the amount of $75,850 is on account of meters. Subcontracting costs for distribution meters have been substantially reduced due to the permanent hire of a new Meter Technician position at the end of 2013.

The remaining variance of $119,128 is on account of the additional costs in the 2012 Actual for the smart meter disposition approved November 1, 2012 (EB-2012-0272) that

are an accumulation of 2009 through to and including 2011 costs previously recorded in HCHI's smart meter deferral accounts.

Maintenance Programs:

The main contributor to the variance in the maintenance programs is in Overhead Distribution Lines on account of poles, conductor, and service work in the amount of $385,620. In 2012 HCHI did not have a full staff complement in the Lines department for a full 12 months. There was a partial year vacancy for a Journeyperson position and a partial year vacancy for the Lines Supervisor position. In addition, HCHI also added a fulltime Lineperson Apprentice position to this department late in 2012. 2013 and 2014 each include the full 12 months of costs for this additional position. HCHI is also forecasting to increase the staff complement in the Operations department by the addition of another fulltime Lineperson Apprentice in 2014 which has been included in the 2014 Test Year costs.

The remaining material variance in this program, in the amount of $82,882, is for tree trimming costs. In 2012 costs associated with tree trimming were based on actual tendered lump sum results to complete line clearing in the north part of HCHI's service territory. The cost of tree trimming will fluctuate from year to year, depending upon which cycle is completed in a particular year. As explained above in the "2014 Test Year versus 2010 Board Approved Variance Analysis", the average tree trimming cost for the entire County was determined, based on two complete 5-year cycles completed to-date, and divided by the 5 year rate period to determine an annualized average tree trimming cost.

Community Relations Programs:

The negative variance of $80,336 from the 2012 Actual to the 2014 Test Year is on account of the costs approved for disposition effective November 1, 2012 for HCHI's Smart Meter Cost Recovery application (EB-2012-0272). These costs related to HCHI's

customer information sessions on TOU pricing, the TOU newspaper and radio advertisements, TOU comparator provided to customers, and the smart meter "Leave Behind Materials" (i.e. door hangers) provided to customers during the smart meter implementation.

Billing and Collecting Programs:

The increase of $101,762 related to meter reading is on account of the costs associated with the base station service fees and FlexNet monitoring services in the new smart meter environment. These service fees were not incurred at a full 100% during 2012. The contractual service levels in the AMI agreement had not been achieved in all months. HCHI exercised its right in accordance with the agreement to commence withholding a portion of the payment for the monthly monitoring fees until the AMI performance met the contracted service levels. Service levels have been achieved in 2013 and the 2014 Test Year includes these costs at 100%. An additional increase is on account of the price escalation applied to the rates of the contract by 1.6% in 2013 and 2.0% in 2014.

The remaining program variance is on account of the smart meter costs approved for disposition November 1, 2012. A decrease of $396,886 from 2012 to 2014 is for meter reading and a decrease of $102,097 is for customer billing costs. These decreases represent smart meter costs actually incurred in 2010 and 2011 related to meter reading and customer billing activities that were previously recorded in deferral accounts and in 2012 recorded in regular OM&A as part of the approved disposition.

Administrative and General Programs:

Management, Administrative, and IT Services labour and general expenses have increased from the 2012 Actual to the 2014 Test Year in the amount of $92,870. This increase is a combination of a vacant Financial Analyst position for part of the 2012 year, which filled, was not hired at job rate, but will reach the job rate in the 2014 Test

Year. Another contributor to this variance is the annual wage increases over the two year period for the Management, Administrative, and IT services.

Two more categories of expenditures have contributed to the overall increase in the program's costs, including: (i) an increase in General Office Expenses of $97,788; and (ii) an increase of $76,863 in ESA and Regulatory Fees. The impact on the General Office Expenses is mainly attributed to the reduction of transformer credits forecast in 2014, as described previously at Tab 1 Schedule 2. The ESA and Regulatory Fee variance is on account of HCHI's change in 2012 for the recording of the OEB's Fixed Cost Assessment fee. HCHI previously recorded these costs in its fiscal year (January 1 to December 31) based on the four invoices received for the OEB's fiscal year (April 1 to March 31). For example, in 2011 the OEB's final invoice for their fiscal year of April 1, 2011 to March 31, 2012 was recorded as a cost in December 2011. In 2012, HCHI implemented that the OEB Fixed Cost Assessment invoices would be recorded based on HCHI's fiscal year. Therefore, HCHI's 2012 Actual only includes three invoices for this regulatory cost, April 1, 2012 to December 31, 2012 and the 2014 Test Year includes a full 12 months of cost. HCHI's 2014 Test Year also includes additional cost awards on account of its 2014 COS rate application.

EMPLOYEE COMPENSATION

Salaries and Wages

Unionized Employees

HCHI's unionized staff is represented by the Local Union 636 of the International Brotherhood of Electrical Workers ("IBEW Local 636") which is the sole bargaining agent for over 80 percent of HCHI's employees. A formal set of contract negotiations was recently conducted and resulted in a new four year collective agreement for the period April 1, 2013 to March 31, 2017. Annual wage increases, in the order of 2.5%, were negotiated for each contract year as follows:

	Year 1	Year 2	Year 3	Year 4
April 1	1.50%	1.50%	1.50%	1.50%
October 1	1.25%	1.25%	1.25%	1.25%

The previous set of contract negotiations resulted in a four year collective agreement for the period April 1, 2009 to March 31, 2013, with negotiated wage increases as follows:

	Year 1	Year 2	Year 3	Year 4
April 1	2.00%	2.00%	2.00%	3.00%
October 1	1.00%	1.00%	1.00%	

During negotiations, HCHI considers the current labour relations environment and wage rates relative to other local distribution companies within its area in order to attract and retain the talent that is required to maintain its distribution system.

Management and Non-Unionized Employees

HCHI provides its non-unionized staff (Senior Managers, Supervisors, Distribution Engineer, Financial Analysts, Executive Assistant, and IT Technician) with an annual salary. In order to reach the "Job Rate" for the position, employees must progress along the salary grid as follows:

- Step 1 upon appointment or promotion into the position.
- Step 2 upon successful completion of the 6-month probationary period.
- Step 3 upon satisfactory completion of 1 year service.
- Job Rate upon satisfactory completion of 2 years' service.

Experience or qualifications may result in a higher starting salary than Step 1.

The salary grid for non-unionized employees was adjusted at the same percentage increases and the same effective dates as those approved for unionized staff over the period April 1, 2013 to March 31, 2017, which is consistent with previous adjustments for the period from April 1, 2009 to March 31, 2013.

Similarly, an extensive review was conducted of non-unionized female job classes to ensure compliance with Pay Equity legislation which resulted in the "*Pay Equity Maintenance Plan – Management, Supervisory, Non-Union Employees*" dated June 30, 2005 signed by the Corporation.

In order to ensure that HCHI is remaining competitive with their compensation package for non-unionized employees, a review is conducted on an annual basis, with reference to The MEARIE Group's report "*Management Salary Survey of Local Distribution Companies"* as a benchmark.

Incentive Pay

HCHI does not have an Incentive Compensation Plan for any of its employees.

Performance Management Program

All employees participate in a formal performance review at each stage of progression and on an "as required" basis to discuss their performance with their immediate Supervisor.

The performance review process allows employees and their immediate Supervisor the opportunity to discuss goals and objectives for the next review period and areas that may require improvement to meet job or performance targets.

The performance review process also provides an opportunity to communicate HCHI's mission, vision, and values and how the employee contributes to the overall success of the organization.

Benefits

A comprehensive and competitive benefits package exists which includes health insurance, life insurance, long-term disability insurance, enriched vacation entitlements, sick time credits, tuition reimbursement, an employee assistance program, and a company-sponsored retirement plan. The benefits are designed to address the health and welfare needs of the employee population with similar coverage for both unionized and non-unionized employees.

HCHI pays 90 percent and employees pay 10 percent of the premiums related to the extended health and dental care plans. Employees are credited with 1 day per month sick leave credit up to a maximum of 130 days to bridge for the long term disability insurance elimination period, as well as to provide assistance during short term illness. There is no vesting of sick days.

Unionized employees are entitled to benefits after their probationary period, which is normally six months after their first day of employment, whereas non-unionized employees are entitled to benefits as of their first day of employment.

Post-Retirement Benefits

HCHI does not provide post-retirement benefits to any of its employees.

OMERS Pension Expense

HCHI's employees are members of the Ontario Municipal Employees Retirement System ("OMERS"), a defined benefit pension plan for employees. HCHI contributes a matching portion for employees as required under the terms of the OMERS pension plan.

The following Table 7 provides details of the employee costs for the 2010 Board Approved, 2010 Actual, 2011 Actual, 2012 Actual, 2013 Bridge Year, and the 2014 Test Year. The number of employees and cost information includes HCHI's 9 Directors within in the "Management (including executive)" line of the table. This information is also filed as OEB Appendix 2-K "Employee Costs".

Table 7
Employee Costs

	Last Rebasing Year - 2010- Board Approved	Last Rebasing Year - 2010- Actual	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Number of Employees (FTEs including Part-Time)						
Management (including executive)	18	18	18	18	18	18
Non-Management (union and non-union)	36	37	37	40	40	42
Total	54	55	55	58	58	60
Total Salary and Wages including ovetime and incentive pay						
Management (including executive)	$ 966,943	923,589	$ 988,143	$ 971,183	$ 1,013,426	$ 1,044,098
Non-Management (union and non-union)	$ 2,298,370	2,220,454	$ 2,421,752	$ 2,517,236	$ 2,753,834	$ 2,935,649
Total	$ 3,265,313	$ 3,144,043	$ 3,409,895	$ 3,488,419	$ 3,767,260	$ 3,979,747
Total Benefits (Current + Accrued)						
Management (including executive)	$ 116,733	$ 94,923	$ 115,039	$ 122,663	$ 163,291	$ 172,592
Non-Management (union and non-union)	$ 321,044	$ 298,315	$ 352,641	$ 396,262	$ 455,403	$ 505,770
Total	$ 437,777	$ 393,238	$ 467,680	$ 518,926	$ 618,693	$ 678,362
Total Compensation (Salary, Wages, & Benefits)						
Management (including executive)	$ 1,083,676	$ 1,018,512	$ 1,103,181	$ 1,093,847	$ 1,176,716	$ 1,216,690
Non-Management (union and non-union)	$ 2,619,413	$ 2,518,769	$ 2,774,393	$ 2,913,498	$ 3,209,237	$ 3,441,419
Total	$ 3,703,090	$ 3,537,282	$ 3,877,575	$ 4,007,345	$ 4,385,953	$ 4,658,109

Notes to Table 7:

1. Full-time position "Conservation Specialist" at work hour compensation costs are charged directly to OPA CDM programs and the related benefit costs are charged to OM&A. The only exception is 2010 Actual – all compensable hours and dollars were charged to CDM Programs. This position is not included in the employee count number for any year and also not included in the 2010 Board Approved employee count or dollars.
2. Contract position "Customer Service & Collections Clerk" at work hour compensation costs charged to Smart Meter deferral accounts and not included in the employee count or dollars for 2010 Board Approved, 2010 Actual and 2011 Actual. This position was included in the 2012 Actual employee count and dollars based on approval for disposition of Smart Meter costs (EB-2012-0272) effective November 1, 2012.

Changes in Workforce Year over Year

2010 Actual versus 2010 Board Approved:

The full-time equivalent ("FTE") employees increased from 54 to 55 between the 2010 Actual and 2010 Board Approved. The addition of one FTE is on account of the new non-unionized Financial Analyst position added in 2010. This new position was essential for the Finance department to sustain its core functions and increasing financial and regulatory reporting requirements. This position allows for the two existing Financial Analysts to be fully cross-trained and available for backup relief when required. Not having staff fully cross-trained increases the risk of the department not being able to meet mandatory deadlines.

The annual unionized and non-unionized scheduled wage increases for the 2010 Actual were 2% on April 1st and 1% on October 1st, as included in the 2010 Board Approved.

2011 Actual versus 2010 Actual:

In the 2011 Actual, the FTE complement did not change from the 2010 Actual of 55; that is, there were no additions or deletions of staff.

The annual unionized and non-unionized scheduled wage increases for the 2011 Actual were 2% on April 1st and 1% on October 1st.

2012 Actual versus 2011 Actual:

The FTE for 2012 Actual was 58, an increase of 3 new from the 2011 Actual. One new position is the Sync Operator, a unionized position in the Customer Service department, required as a result of the implementation of smart meters. This position synchronizes functions between the AMI, the MDM/R, the ODS, and the Harris billing system, and works as a gatekeeper for critical service order activity that touches the smart meter (non-communicating meters), ensures accuracy of TOU meter data for billing purposes, and monitors and verifies that all smart meter data has been processed and meets MDM/R requirements. Another new position is a Lineperson Apprentice, a unionized position in the Operations department. This addition was part of a two year program to increase the number of Power line Workers from HCHI's 2011 complement of 12 linepersons to 14. HCHI currently has three line crews, including Trouble/Service, Demand Work, and Construction, with a fourth crew for maintenance with workers typically taken from the other three crews. HCHI utilizes contracted line crews to complete required safety improvements to the distribution system as identified through the annual OEB system inspection work. By increasing the complement of internal staff, the demand and construction crews are able to complete their work in a timely manner and the work currently performed by the line contractor is able to be completed internally by HCHI's own line crews. The final position added in 2012 was the non-unionized Distribution Engineer position. This position plays a key role in the development of new technologies in two main areas, including distributed generation ("DG") and smart grid. The Distribution Engineer also reviews and analyzes the

distribution protection and control systems in place required as a result of the increase in DG activity.

The annual unionized and non-unionized scheduled wage increase for the 2012 Actual was 3% on April 1st.

2013 Bridge Year versus 2012 Actual:

In the 2013 Bridge Year the FTE complement of 58 is forecast not to change from 2012 Actual; that is, there are no additions or deletions of staff.

The annual unionized and non-unionized scheduled wage increase for the 2013 Bridge Year are1.50% on April 1s and 1.25% on October 1st.

2014 Test Year versus 2013 Bridge Year:

In the 2014 Test Year the FTE complement is forecast to increase by two positions to a total of 60. One of these new positions is a Lineperson Apprentice unionized position. This is the second of the two positions discussed above in the "2011 Actual versus 2012 Actual" variance analysis required to reach a total complement of 14 linepersons in the Operations department over the two year period from 2012 to 2014. The second new position in the 2014 Test Year is a new Meter Technician unionized position. Currently a third party contractor performs the locate services for HCHI. Hiring one additional full-time meter technician will eliminate the need for this third party contractor and the dispatching of locate and meter work orders will be more efficient and organized. HCHI expects to have the new staff member hired by the end of 2013.

The annual unionized and non-unionized scheduled wage increases for the 2014 Test Year are 1.50% on April 1st and 1.25% on October 1st.

SHARED SERVICES AND CORPORATE COST ALLOCATION

Introduction

Haldimand County Hydro Inc. ("HCHI") currently performs streetlight maintenance for its Shareholder, the Corporation of Haldimand County (the "Municipality") and water billing and sentinel light services for its affiliate, Haldimand County Energy Inc. ("HCEI"). Actual costs including labour and burden, stores material and burden, and vehicle costs are charged to HCEI.

A summary of charges to affiliates for services provided in 2010 Actual, 2011 Actual, 2012 Actual, the 2013 Bridge Year and 2014 Test Year are shown in the following Table 8. Some of these charges include:

- Tree trimming and removals which occur when such work benefits both the utility and the Municipality but the utility's contractor does the work; and
- Pole relocations which occur in conjunction with municipal road widening.

There are no Board of Director related costs for affiliates, Haldimand County Utilities Inc. ("HCUI") and HCEI, included in HCHI's costs.

Table 9 provides a summary of charges from affiliates for services provided to HCHI in 2010 Actual, 2011 Actual, 2012 Actual, the 2013 Bridge Year and 2014 Test Year.

The information contained in Tables 8 and 9 is also filed in OEB Appendix 2-N "Corporate Cost Allocation". Pricing methodology for the shared services provided to/from HCHI follows each respective table. The variance analysis for charges to/from HCHI for the 2014 Test Year compared to the 2012 Actual and the 2010 Board Approved also follows these two tables.

Table 8
Shared Services Summary – HCHI to Affiliates

Service	Pricing Methodology	2010 Actual	2011 Actual	2012 Actual	2013 Bridge	2014 Test	Variance 2014 Test vs 2010 Actual (Last Board Approved)	Variance 2014 Test vs. 2012 Actual
HCHI Charges to Haldimand County:								
Street Light Maintenance	Cost-Base	$ 87,091	$ 84,209	$ 77,715	$ 86,617	$ 86,617	$ (474)	$ 8,902
Street Lighting Projects	Cost-Base	5,141	14,427	4,805	-	-	(5,141)	(4,805)
Tree Trimming & Removals (Cost Share to County)	Cost-Base	14,387	8,057	8,887	2,953	-	(14,387)	(8,887)
Pole Relocations or New Pole Installs (at the Request of the County)	Cost-Base	16,951	-	-	-	-	(16,951)	-
Supply and Install Transformers	Cost-Base	31,315	-	2,901	-	-	(31,315)	(2,901)
Miscellaneous Relocation & Service	Cost-Base	-	-	1,899	-	-	-	(1,899)
HCHI Charges to HCEI								
Water & Wastewater Billing & Collecting Fee	Cost-Base	365,737	364,650	374,857	374,205	374,205	8,468	(652)
Sentinel Light Maintenance	Cost-Base	20,111	16,666	16,992	21,044	20,438	327	3,446
Billing & Collecting Labour for Sentinel Lights	Cost-Base	2,465	2,394	2,314	2,175	2,055	(410)	(259)
Management & Administrative Salaries	Cost-Base	27,027	27,849	28,821	29,076	30,442	3,415	1,621
HCHI Charges to HCUI								
Management & Administrative Salaries	Cost-Base	27,027	27,849	28,821	29,076	30,442	3,415	1,621
Totals		**$ 597,252**	**$ 546,101**	**$ 548,012**	**$ 545,146**	**$ 544,199**	**$ (53,053)**	**$ (3,813)**

Methodology Used in Determining Prices Charged to Affiliates

The services HCHI provide to the Municipality are charged on a cost-based price plus mark-ups to cover overheads as follows:

- Material – Actual cost plus 16% burden;
- Labour – Actual labour hours times wage rate plus a 50% burden;
- Trucks – Actual usage hours times unit rate (calculated based on all costs associated with each truck); and
- Administrative – 10% burden charged on entire invoice.

The cost sharing services charged to the Municipality are per agreements put into place at the time each particular non-affiliate third party service is required and is based on the percentage of the service to be allocated to each party.

The services provided to each of HCEI and HCUI is also charged at a cost-based price plus a mark-up on labour and truck as noted above, including: (i) Management and Administrative Salaries are charged out at 1 day per month plus the 50% burden; (ii) Billing and Collecting Labour on account of sentinel lights is charged out at $0.25 per sentinel light rental; (iii) sentinel light maintenance costs are directly allocated to HCEI for every labour hour plus burden and truck hour worked, and material issued plus applicable burdens; and (iv) the water & wastewater billing and collecting administrative fee is calculated as 85% of the fee that HCEI collects from the Municipality. The fee to the Municipality is calculated using direct and indirect costs related to the service allocated based on the number of water customers to the total water and electric customers.

The methods described above to invoice affiliates for services HCHI provides to them are consistent with that utilized to invoice any other non-affiliate for work performed. Periodic increases in labour, equipment, contractor and material costs are passed on to affiliates and non-affiliates as they occur.

There has been no third party review of the pricing methodology used in the charges from HCHI to affiliates. This is consistent with the methodology included in HCHI's 2010 COS rate application (EB-2009-0265) with Settlement Agreement approved February 18, 2010 and Decision and Order issued March 31, 2010. Accordingly, HCHI considers this pricing methodology to still be appropriate, and continues with it as a method of fully allocating costs between HCHI and its affiliates.

Table 9
Shared Services Summary – Affiliates to HCHI

Service	Pricing Methodology	2010 Actual	2011 Actual	2012 Actual	2013 Bridge	2014 Test	Variance 2014 Test vs 2010 Actual (Last Board Approved)	Variance 2014 Test vs. 2012 Actual
Haldimand County Charges to HCHI:								
Bank Service Charges re: Debenture Handling	Cost-Base	$ 8,437	$ -	$ -	$ -	$ -	$ (8,437)	$ -
HCUI Charges to HCHI								
Management Fee	Cost-Base	54,000	54,000	54,000	54,000	54,000	-	-
Totals		**$ 62,437**	**$ 54,000**	**$ 54,000**	**$ 54,000**	**$ 54,000**	**$ (8,437)**	**$ -**

Methodology Used in Determining Prices Charged from Affiliates

The annual management fee of $54,000 charged to HCHI by HCUI is on account of administration expenses for services provided by the parent company, HCUI's, Board of Directors, for governance and oversight services on behalf of HCHI. An annual management fee of $6,000 is also charged to HCEI by HCUI for similar services.

There has been no third party review of the pricing methodology used in the charges from affiliates to HCHI. This is consistent with the methodology included in HCHI's 2010 COS rate application (EB-2009-0265). The Management Fee has not changed since the 2010 COS through to the 2014 Test Year as detailed in Table 9 above. Accordingly, HCHI considers this pricing methodology to still be appropriate, and continues with it as a method of fully allocating costs between HCHI and its affiliates.

Variance Analysis – HCHI Charges to Affiliates

2014 Test Year versus 2010 Actual

Total variance in charges from HCHI to its affiliates is a decrease of $53,053. This is largely due to specific projects that occurred in 2010 that are "as required" at the request of the affiliate, the Municipality. These types of transactions do not occur each year. An additional contributor to the variance is the tree trimming requests made by

the Municipality, as required and at their request. The offsetting increases in the variance in the salaries charged to both HCUI and HCEI by HCHI are on account of the annual wage increases discussed at Tab 2, Schedule 4 of this Exhibit. The water and wastewater billing and collecting fee increase is on account of an increase to the rate effective April 1, 2012.

2014 Test Year versus 2012 Actual

The overall variance from the 2012 Actual to the 2014 Test Year is a $3,813 decrease. This is a combination of the specific project requests in 2012 by the Municipality and the specific "as required" requests for tree trimming. These types of items have not been forecasted to occur in 2014 as they are not consistent and vary from year to year. The offsetting increases in the total variance is in the salaries charged to both HCUI and HCEI by HCHI on account of the annual scheduled wage increases, a forecasted increase in the streetlight maintenance based on activity to-date in 2013 with the 2012 Actual lower than average, and a forecasted increase in sentinel light maintenance.

Variance Analysis – Affiliate Charges to HCHI

2014 Test Year versus 2010 Actual

The decrease from the 2010 Actual to the 2014 Test Year is on account of the bank service charges for debenture handling from the Municipality to HCHI have ceased as those debentures were paid in full May 1, 2010.

2014 Test Year versus 2012 Actual

There is no variance between the 2012 Actual and the 2014 Test Year.

Revenue Reconciliation – Shared Services versus Other Operating Revenue

In Table 8, "Shared Services Summary – HCHI to Affiliates", the only item that is recorded in Other Operating Revenue is the water and wastewater billing and collecting

fee. All of the other charges for services provided to the Municipality are recorded in balance sheet miscellaneous accounts receivable accounts and the balance of the charges to HCEI and HCUI are recorded as a credit in the appropriate OM&A accounts affected. For example, the charge for Management salaries to both HCEI and HCUI is recorded as a reduction in account 5610. In Table 9, "Shared Services Summary – Affiliates to HCHI", the items have been recorded to the appropriate OM&A account.

The following Table 10 provides reconciliation between the revenue arising from the OEB's Appendix 2-N "Corporate Cost Allocation" and the revenue in OEB's Appendix 2-H "Other Operating Revenue".

Table 10
Revenue Reconciliation
Shared Services & Other Operating Revenue

Service	2010 Actual	2011 Actual	2012 Actual	2013 Bridge	2014 Test
Appendix 2-N - Corporate Cost Allocation					
HCHI Charges to HCEI					
Water & Wastewater Billing & Collecting Fee	365,737	364,650	374,857	374,205	374,205
Appendix 2-H - Other Operating Revenue					
Account 4375 - Revenues from Non-Rate Regulated Utility Operations	365,737	364,650	374,857	374,205	374,205
Difference	-	-	-	-	-

Purchase of Products and Services from Non-Affiliates

HCHI purchases many services from non-affiliated vendors. Some of these vendors are determined through a tendering process and some are solely based on market price or regulated price. HCHI does not have control over the regulated pricing structures or the market prices, such as for the cost of postage.

However, for the majority of the balance of vendor services, HCHI generally purchases services utilizing a competitive bidding process. This process is used for contracts expected to exceed $50,000 and those services below this amount where the marketplace has multiple vendors. The instruments used to procure services ranges from formal tenders, request for quotations (RFQs), and request for proposals ("RFP"). HCHI has a mature base template for all of the instruments noted and this documentation includes detailed requirements and descriptions as follows:

- Project/Service Overview
- Procurement Process
- Contractor Information Requirements
- HCHI's Business Process Requirements
- Terms and Conditions

The base template is adjusted to include elements which are appropriate for the service being procured. Most contracts are for one year and a number of contracts have provisions to extend the contract by up to two more years. In all cases, the bids are measured against the information requested in the instrument taking into consideration the cost. Generally, the lowest bid meeting the requirements of the instrument is selected. HCHI's Purchasing Policy has been included as Appendix A.

Tables 11, 12 and 13 below identify purchased services from non-affiliated vendors for expenditures where the annual total was greater than the materiality threshold of

$64,000 in each of the actual years 2010, 2011, and 2012 respectively. These tables contain the historical non-affiliate supplier information including vendor name, type of service, the procurement method used, and the total annual purchases.

Table 11
2010 Non-Affiliated Purchased Services over $64,000

Vendor Name	Services	Procurement Method	Total Purchases
Olameter Inc.	Meter Reading Services	RFQ	$ 410,785
Black & McDonald Ltd.	Contractor - Distribution System Work	Tender	$ 267,823
Oakhill Tree Service Ltd. Davey Tree Expert Co. of Canada Ltd.	Tree Trimming Services	Tender	$ 251,496
MEARIE Management Inc.	Employee Benefit Provider	RFQ	$ 198,848
Utility Scanning Solutions Ltd.	Contractor - Distribution System Work	RFQ	$ 187,295
Canada Post	Postage and Bulk Mailing Costs	Market Price	$ 152,850
Aeon Egmond Ltd.	Distribution Station (ESA Ph. II) and Remediation Work	RFQ and Direct Quote	$ 92,948
GE Fleet Services	Fuel for Vehicle Fleet	Market Price	$ 87,866
Ontario Energy Board	Regulatory Fees and Cost Awards	Regulated	$ 86,711
Harris Computer Systems	IT Services - Billing System	RFQ	$ 80,963
Borden Ladner Gervais LLP	Rate Application Consulting &Legal, and Legal Services for Distribution Activities	Direct Quote	$ 76,896
Peterborough Utilities Services Inc.	Wholesale Settlements Provider	RFQ	$ 71,467

Table 12
2011 Non-Affiliated Purchased Services over $64,000

Vendor Name	Services	Procurement Method	Total Purchases
Black & McDonald Ltd.	Contractor - Distribution System Work	Tender	$ 392,034
Utility Scanning Solutions Ltd.	Contractor - Distribution System Work	RFQ	$ 217,513
Aeon Egmond Ltd.	Distribution Station (ESA Ph. II) and Remediation Work	RFQ and Direct Quote	$ 209,950
Olameter Inc.	Meter Reading Services	RFQ	$ 202,900
MEARIE Management Inc.	Employee Benefit Provider	RFQ	$ 191,761
Beswick Tree Service Ltd. Davey Tree Expert Co. of Canada Ltd. Oakhill Tree Service Ltd.	Tree Trimming Services	Tender	$ 187,559
Canada Post	Postage and Bulk Mailing Costs	Market Price	$ 144,000
Harris Computer Systems	IT Services - Billing System	RFQ	$ 100,773
GE Fleet Services	Fuel for Vehicle Fleet	Market Price	$ 98,143
Aird and Berlis LLP	Legal Services related to Transmission	Direct Quote	$ 81,492
Haldimand Insurance Brokers Ltd.	Commercial Insurance Policies	Direct Quote	$ 74,950
Ontario Energy Board	Regulatory Fees and Cost Awards	Regulated	$ 74,516
Peterborough Utilities Services Inc.	Wholesale Settlements Provider	RFQ	$ 73,884

Table 13
2012 Non-Affiliated Purchased Services over $64,000

Vendor Name	Services	Procurement Method	Total Purchases
D. L. Hannon Inc. Black & McDonald Ltd.	Contractor - Distribution System Work	Tender	$ 372,463
MEARIE Management Inc.	Employee Benefit Provider	RFQ	$ 232,183
Utility Scanning Solutions Ltd.	Contractor - Distribution System Work	RFQ	$ 193,033
Beswick Tree Service Ltd. Davey Tree Expert Co. of Canada Ltd.	Tree Trimming Services	Tender	$ 183,908
Canada Post	Postage and Bulk Mailing Costs	Market Price	$ 179,000
Olameter Inc.	Meter Reading Services	RFQ	$ 140,721
Rodan Energy Solutions Inc.	Contractor - Distribution Metering Work	RFQ	$ 119,150
ARI Financial Services GE Fleet Services	Fuel for Vehicle Fleet	Market Price	$ 112,162
Harris Computer Systems	IT Services - Billing System	RFQ	$ 100,393
Ontario Energy Board	Regulatory Fees and Cost Awards	Regulated	$ 92,964
Peterborough Utilities Services Inc.	Wholesale Settlements Provider	RFQ	$ 80,851
Sensus Metering Systems Canada Inc.	Smart Meter Reading Services	RFQ	$ 78,272
DBL-DIP Inc.	Contractor - Distribution System Work	RFQ	$ 76,294
MEARIE	Liability Insurance Policy	Direct Quote	$ 66,384
ESRI Canada	IT Services - Mapping System	Direct Quote	$ 64,387

ONE TIME COSTS

HCHI has not included any one-time costs in the 2014 OM&A, with the exception of legal and consultant costs related to completing this Application. The total estimated costs for completing this Application have been divided equally and spread over a five year rate period.

The following Tables 14 15 in Tab 2, Schedule 8 of this Exhibit provide details of these costs.

REGULATORY COSTS

Regulatory costs for the preparation, review, and defense of HCHI's 2014 COS rate application total $148,500 as compared to $222,500 approved in HCHI's 2010 COS rate application. These costs include incremental consulting costs related to LRAM, Asset Condition Assessment and the rate application itself, and anticipated Board, legal, and Intervenor costs through to the end of the rate approval process.

The total costs associated with the 2014 COS rate application for legal and consultant costs have been spread over the 5 year rate period beginning with 2014; that is, $18,100 (i.e. one-fifth) has been included in the OM&A for the 2014 Test Year. This is the same treatment as the regulatory costs of $222,500 approved in the 2010 COS rate application spread over the four year rate period, with $55,625 (i.e. one-quarter) included in the 2010 Test Year OM&A.

Table 14 provides details of the regulatory costs included in each of the 2010 Board Approved, 2012 Actual, 2013 Bridge Year and 2014 Test Year OM&A.

Table 14
Regulatory Costs

Description	USoA Account	Type of Cost	2010 Board Approved	2012 Actual Year	2013 Bridge Year	Annual % Change	2014 Test Year	Annual % Change
	(B)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
OEB Annual Assessment	5655	On-Going	$ 75,428	$ 64,217	$ 84,056	30.89%	$ 88,100	4.81%
OEB Annual Registration Fee	5655	On-Going	$ 800	$ 800	$ 800	0.00%	$ 800	0.00%
OEB Section 30 Costs (Applicant-originated)	5655							
OEB Section 30 Costs (OEB-initiated)	5655	On-Going	$ 2,000	$ 6,192	$ 3,310	(46.54%)	$ 5,000	51.06%
Expert Witness costs for regulatory matters								
Legal costs for regulatory matters	5630	One-Time	$ 15,000				$ 6,000	
Consultants' costs for regulatory matters	5630	One-Time	$ 28,625	$ 5,199	$ 118,160	354.55%	$ 12,100	51.20%
Other regulatory agency fees or assessments	5655	On-Going	$ 10,980	$ 11,603	$ 11,522	(0.70%)	$ 12,345	7.14%
Any other costs for regulatory matters ("Notice of Application" publication costs)	5655	On-Going		$ 4,959	$ 3,000	(39.50%)	$ 3,000	0.00%
Any other costs for regulatory matters (EB-2007-0002 - Cost Allocation Review - Refund from the Hydro One Load Data Research Group)	5655	One-Time		$ (1,577)		(100.00%)		
Intervenor costs	5655	One-Time	$ 12,000	$ 1,188	$ 190	(84.01%)	$ 55,000	5689.47%
Sub-total - Ongoing Costs			**$ 89,208**	**$ 87,771**	**$ 102,688**	**17.00%**	**$ 109,245**	**6.39%**
Sub-total - One-time Costs			**$ 55,625**	**$ 4,810**	**$ 118,350**	**2360.50%**	**$ 73,100**	**(38.23%)**
Total			**$ 144,833**	**$ 92,581**	**$ 221,038**	**138.75%**	**$ 182,345**	**(17.51%)**

Table 15 provides details of the one-time costs related to the preparation of this 2014 COS rate application that have been spread over the 5 year rate period. The information contained in both Tables 14 and 15 has also been included in the OEB Appendix 2-M "Regulatory Costs".

Table 15
One Time Regulatory Costs

Description	2013 Bridge Year	2014 Test Year	Total
Legal costs		$ 30,000	$ 30,000
Consultants' costs		$ 60,500	$ 60,500
Intervenor costs			$ -
Total	**$ -**	**$ 90,500**	**$ 90,500**

LOW INCOME ASSISTANCE PROGRAM (LEAP)

HCHI has included $16,500 in the 2014 Test Year OM&A for the Low Income Assistance Program ("LEAP") under account 6205 – Donations – Sub-account LEAP Funding.

This amount is based on 0.12% of the 2010 Board Approved total Distribution Revenue Requirement (Service Revenue Requirement) of $13,735,891. HCHI has also included $16,500 in the 2013 Bridge Year OM&A based on 0.12% of the 2010 Board Approved total Distribution Revenue Requirement.

No amount has been included in the 2014 Revenue Requirement for legacy programs, such as Winter Warmth.

CHARITABLE AND POLITICAL DONATIONS

HCHI has not included charitable or political donations in OM&A expenses for any of the 2010 through 2012 Actuals, the 2013 Bridge Year or the 2014 Test Year. HCHI does not make charitable donations because of its status as a municipally-owned entity.

DEPRECIATION AND AMORTIZATION

Depreciation Policy

The Filing Requirements indicate that the applicant must provide a copy of its depreciation/amortization policy, if available. HCHI does not have a written depreciation policy document. However, the depreciation practices followed in the past and used in preparing this Application are described below.

Depreciation of capital assets is calculated as follows:

- HCHI uses the pooling of assets for all Distribution System capital assets. General Plant capital assets are recorded on an individual basis;
- Depreciation is calculated on a straight line basis over the estimated remaining useful life of the assets at the end of the previous year;
- Depreciation on capital additions during the current year commences on the day that the asset is put into service; and
- Depreciation rates up to and including 2012 were in accordance with the rates set out in the OEB's APH. However, as indicated in Exhibit 1, Tab 5, Schedule 16, HCHI has made the appropriate accounting changes under CGAAP for depreciation expense and applied the typical useful lives as set out in the Kinectrics Report. These changes were made effective January 1, 2013 as mandated by the Board in its letter dated July 17, 2012. This accounting change is discussed in more detail at Tab 3, Schedule 3 of this Exhibit and in Exhibit 2, Tab 5, Schedule 5.

HCHI does not have any Asset Retirement Obligations.

DEPRECIATION TABLES

Table 16 below provides details of the deprecation rates used up to and including 2012 Actual ("Prior Useful Life") and the new useful life ("Adjusted Useful Life") effective January 1, 2013. This information has also been included on OEB Appendix 2-BB "Service Life Comparison".

Table 16
Depreciation Rates Pre & Post Useful Life Adjustment

		Kinectrics Asset Depreciation Study			
Asset Type and APH Account	**Prior Useful Life**	Useful Life Min	Useful Life Typical	Useful Life Max	**Adjusted Useful Life**
Account 1820 - Distribution Station Equipment	30				
Substation Transformers		30	45	60	**45**
Vacuum Station Breakers		35	45	65	**45**
Account 1830 - Poles / Towers / Fixtures	25				
Concrete Poles		50	60	80	**60**
Metal Poles		60	60	80	**60**
Wood Poles		35	45	75	**50** [1]
Account 1835 - Overhead Conductor & Devices	25				
Conductor		50	60	75	**50** [2]
Gang-Operated Line Switches		30	45	55	**45**
Reclosers		25	40	55	**40**
Account 1840 - Underground Conduit	25				
U/G Conduit - Duct		30	50	85	**50**
Account 1845 - Underground Conductor	25				
U/G XLPE Cable – Direct Buried (Non-Duct)		25	30	35	**30**
U/G XLPE Cable – In Duct		35	40	55	**40**
Pad-Mounted Switch Gear		20	30	45	**30**
Account 1850 - Transformers	25				
Pole-Top		30	40	60	**40**
Pad-Mount		25	40	45	**40**
Step-Down(Rabbits)		30	40	60	**40**
Account 1855 - Distribution Services	25				
O/H Conductor (Secondary)		50	60	75	**60**
U/G Cable Direct Buried (Secondary)		25	35	40	**35**
Account 1860 - Meters					
Primary Metering Units	25	15		30	**20**
Smart Meters	15	5		15	**15**
Interval Meters & Other Metering Equipment	25	25		50	**15** [3]
General Plant					
Account 1908 - Buildings and Fixtures	50	50		75	**50**
Account 1915 - Office Furniture and Equipment	10	5		15	**10**
Account 1920 - Computer Hardware	5	3		5	**5**
Account 1925 - Computer Software	5	2		5	**5**
Account 1930 - Transportation Equipment - Buckets	8	5		15	**12**
Account 1930 - Transportation Equipment - Pickups / Vans	8	5		10	**8**
Account 1930 - Transportation Equipment - Trailers	8	5		20	**20**
Account 1940 - Tools, Shop and Garage Equipment	10	5		10	**10**
Account 1955 - Communication Equipment	5	2		10	**5**

Notes:
1. HCHI experiences an average replacement on wood poles at 49 years. ACA report shows 20% failure rate at 45 years and 90% failure rate at 75 years. Assign a typical useful life of 50 years.
2. Overhead conductor is typically replaced at the same time as the wood pole and attracts the same typical useful life of 50 years.
3. Interval meters, CTs and PTs, and Meter Cabinets assigned the same typical useful life as the Smart Meter. Not part of the Kinectrics ACA report.

Table 17 that follows provides a summary of depreciation expense for the years 2010 to 2012 Actual prior to the useful lives' adjustment, and the 2013 Bridge Year and 2014 Test Year after the useful lives adjustment, all reconciled to the fixed asset continuity schedules for the rate base as required by the Filing Requirements.

Table 17
Summary of Depreciation Expense for 2010 to 2014

CCA Class	OEB	Description	2010	2011	2012	2013	2014
CEC	1609	Distribution Station Equipment - Capital Contributions Paid	$ -	$ -	$ -	$ 332	$ 5,571
47	1820	Distribution Station Equipment - Normally Primary below 50 kV	23,512	17,266	17,295	8,035	8,091
47	1830	Poles, Towers and Fixtures - Wood Poles	825,705	863,874	922,254	287,600	322,835
47	1830	Poles, Towers and Fixtures - Metal/Concrete Poles				835	835
47	1835	Overhead Conductors and Devices-Conductor	446,745	486,457	555,459	210,754	234,423
47	1835	Overhead Conductors and Devices - Switches				7,260	7,437
47	1835	Overhead Conductors and Devices - Reclosures				8,446	8,446
47	1840	Underground Conduit - Duct	17,743	20,443	28,384	30,125	41,113
47	1845	Underground Conductors and Devices - Cable (Non-Duct)	318,216	328,265	313,961	173,968	174,523
47	1845	Underground Conductors and Devices - Cable (In Duct)				33,438	48,562
47	1845	Underground Conductors and Devices - Switchgear				2,915	4,884
47	1850	Line Transformers - Pole Top	441,181	464,341	492,175	188,586	202,097
47	1850	Line Transformers - Padmount				53,924	58,864
47	1850	Line Transformers - Step-Down (Rabbits)				7,418	8,550
47	1855	Services - Overhead	92,686	98,767	105,464	13,931	15,798
47	1855	Services - Underground				44,340	48,152
47	1860	Meters - Primary Metering Units	114,955	118,348	117,787	6,836	9,012
47	1860	Meters - Interval Meters & Other Metering Equipment				218,149	192,515
47	1860	Meters - Stranded Conventional Meters				42,501	-
47	1860	Meters - Smart Meters	-	-	757,661	247,073	252,371
CEC	1612	Land Rights (Formally known as Account 1906)	20,721	20,721	20,777	20,720	20,720
1 b	1908	Buildings and Fixtures	48,202	50,456	51,520	51,715	51,730
8	1915	Office Furniture and Equipment	30,742	30,691	29,830	23,021	22,044
50	1920	Computer Equipment - Hardware	52,405	57,281	79,968	67,921	65,786
50	1611	Computer Software (Formally known as Account 1925)	324,388	354,793	360,638	324,494	221,292
10	1930	Transportation Equipment - Bucket Trucks	165,552	162,393	188,244	97,234	105,859
10	1930	Transportation Equipment - Pickups and Vans				39,005	55,172
10	1930	Transportation Equipment - Trailers				2,000	2,000
8	1940	Tools, Shop and Garage Equipment	48,478	55,052	56,592	59,581	56,600
8	1955	Communication Equipment	1,800	3,511	3,861	3,860	3,861
47	1995	Contributions and Grants - Wood Poles	(144,565)	(154,826)	(161,263)	(13,528)	(14,792)
47	1995	Contributions and Grants - O/H Conductor				(3,758)	(3,863)
47	1995	Contributions and Grants - O/H Line Switches				(167)	(167)
47	1995	Contributions and Grants - O/H Reclosures				(167)	(167)
47	1995	Contributions and Grants - U/G Conduit				(6,494)	(7,820)
47	1995	Contributions and Grants - U/G Conductor (Non-Duct)				(34,702)	(34,702)
47	1995	Contributions and Grants - U/G Conductor (In Duct)				(9,333)	(15,293)
47	1995	Contributions and Grants - Pole Top Transformers				(15,109)	(15,900)
47	1995	Contributions and Grants - Padmount Transformers				(4,758)	(6,297)
47	1995	Contributions and Grants - Step-Down Transformers				(490)	(490)
47	1995	Contributions and Grants - O/H Services				(2,223)	(2,555)
47	1995	Contributions and Grants - U/G Services				(7,056)	(7,740)
47	1995	Contributions and Grants - Primary Metering Units				(8,431)	(8,431)
47	1995	Contributions and Grants - Interval & Other Metering Equip				(2,781)	(2,875)
47	1995	Contributions and Grants - Smart Meters				(9,667)	(10,094)
		Total Depreciation as per Fixed Asset Continuity Schedules	**$2,828,466**	**$2,977,833**	**$3,940,607**	**$2,157,353**	**$2,117,957**
		Less: CDM-OPA Allocated Costs - Depreciation:					
		Building		925	927	946	916
		Office Equipment		563	537	421	390
		Computer Hardware		1,050	1,435	1,243	1,164
		Computer Software		1,106	1,431	1,207	1,499
		Total Depreciation Expense	**$2,828,466**	**$2,974,189**	**$3,936,277**	**$2,153,536**	**$2,113,988**

The year over year fluctuations in depreciation expense shown in Table 17 above are natural variances based on capital additions, disposal of assets, and assets becoming fully depreciated in a given year. An additional contributor to the large increase in 2012 is on account of the depreciation expense in the amount of $762,272 added for the smart meter assets approved for disposition effective November 1, 2012 (EB-2012-0272) . This amount is comprised of $715,893 in the Meters (1860) category, $21,785 in the Computer Hardware (1920) category, and $24,594 in the Computer Software (1925/1611) category. The decrease for 2013 is mainly due to the implementation of the accounting change for useful lives which reduced depreciation. Stranded meters were also removed from the capital assets as at December 31, 2013 and transferred to the appropriate deferral sub-account of 1555 for a request for disposition as part of this Application, discussed in further detail in Exhibit 9, Tab 3, Schedule 1.

Depreciation expense for the 2013 Bridge Year and the 2014 Test Year complies with the half-year rule, in which six months of depreciation is recorded in the acquisition year. Depreciation expense for each of the Actuals is calculated commencing on the asset in service date.

The Fixed Asset Continuity Schedules for each year can be found in Exhibit 2, Tab 2, Schedule 1, which reconcile to the balance included in Table 17 above. These continuity schedules are also found in the OEB Appendix 2-BA1 “Fixed Asset Continuity - CGAAP”.

The OEB Appendices 2-CR “Old CGAAP Depreciation Expense 2012”; 2-CS “Old CGAAP Depreciation Expense 2013”; 2-CT “New CGAAP Depreciation Expense 2013”; and 2-CU “New CGAAP Depreciation Expense 2014” have been included with this Application and in the following Tables 18, 19, 20, and 21 respectively.

Table 18
2012 Depreciation Expense – Old CGAAP

Appendix 2-CR
Depreciation and Amortization Expense

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013

Year 2012 Former CGAAP - CGAAP without the changes to the policies

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2012 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2012 Depreciation Expense (h) = (e) / (f)	2012 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1820	Distribution Station Equipment <50 kV	$ 466,497		**$ 466,497**	$ -	**$ 466,497**	30.00	3.33%	**$ 15,550**	$ 17,295	**-$ 1,745**
1830	Poles, Towers & Fixtures	$ 19,408,683		**$ 19,408,683**	$ 1,218,769	**$ 20,018,068**	25.00	4.00%	**$ 800,723**	$ 922,254	**-$ 121,531**
1835	Overhead Conductors & Devices	$ 11,757,488		**$ 11,757,488**	$ 1,799,487	**$ 12,657,232**	25.00	4.00%	**$ 506,289**	$ 555,459	**-$ 49,170**
1840	Underground Conduit	$ 633,781		**$ 633,781**	$ 732,415	**$ 999,989**	25.00	4.00%	**$ 40,000**	$ 28,384	**$ 11,616**
1845	Underground Conductors & Devices	$ 7,292,189		**$ 7,292,189**	$ 410,064	**$ 7,497,221**	25.00	4.00%	**$ 299,889**	$ 313,961	**-$ 14,072**
1850	Line Transformers	$ 11,614,068		**$ 11,614,068**	$ 773,837	**$ 12,000,987**	25.00	4.00%	**$ 480,039**	$ 492,175	**-$ 12,136**
1855	Services (Overhead & Underground)	$ 2,551,801		**$ 2,551,801**	$ 131,291	**$ 2,617,447**	25.00	4.00%	**$ 104,698**	$ 105,464	**-$ 766**
1860	Meters	$ 3,131,706		**$ 3,131,706**	-$ 97,584	**$ 3,082,914**	25.00	4.00%	**$ 123,317**	$ 117,787	**$ 5,530**
1860	Meters (Smart Meters)	$ -		**$ -**	$ 3,724,761	**$ 1,862,381**	15.00	6.67%	**$ 124,159**	$ 757,661	**-$ 633,502**
1905	Land	$ 131,279		**$ 131,279**	-$ 4,140	**$ 129,209**			**$ -**	$ -	**$ -**
1612	Land Rights (Formally known as Account 1906)	$ 695,389		**$ 695,389**	$ -	**$ 695,389**	50.00	2.00%	**$ 13,908**	$ 20,777	**-$ 6,869**
1908	Buildings & Fixtures	$ 2,168,016		**$ 2,168,016**	$ 22,502	**$ 2,179,267**	50.00	2.00%	**$ 43,585**	$ 51,520	**-$ 7,935**
1915	Office Furniture & Equipment (10 years)	$ 363,142	$ 129,180	**$ 233,962**	$ 2,494	**$ 235,209**	10.00	10.00%	**$ 23,521**	$ 29,830	**-$ 6,309**
1920	Computer Equipment - Hardware	$ 517,537	$ 248,841	**$ 268,696**	$ 67,558	**$ 302,475**	5.00	20.00%	**$ 60,495**	$ 79,968	**-$ 19,473**
1611	Computer Software (Formally known as Account 1925)	$ 2,584,483	$ 1,062,007	**$ 1,522,476**	$ 180,586	**$ 1,612,769**	5.00	20.00%	**$ 322,554**	$ 360,638	**-$ 38,084**
1930	Transportation Equipment	$ 2,087,570	$ 592,982	**$ 1,494,588**	$ 120,076	**$ 1,554,626**	8.00	12.50%	**$ 194,328**	$ 188,244	**$ 6,084**
1940	Tools, Shop & Garage Equipment	$ 707,839	$ 224,145	**$ 483,694**	$ 87,199	**$ 527,294**	10.00	10.00%	**$ 52,729**	$ 56,592	**-$ 3,863**
1955	Communications Equipment	$ 68,074	$ 48,770	**$ 19,304**	$ -	**$ 19,304**	5.00	20.00%	**$ 3,861**	$ 3,861	**-$ 0**
1995	Contributions & Grants	-$ 3,953,284		**-$ 3,953,284**	-$ 190,388	**-$ 4,048,478**	25.00	4.00%	**-$ 161,939**	-$ 161,263	**-$ 676**
etc.											
	Total	**$ 62,226,258**	**$ 2,305,925**	**$ 59,920,333**	**$ 8,978,927**	**$ 64,409,797**			**$ 3,047,705**	**$ 3,940,607**	**-$ 892,902**

Table 19
2013 Depreciation Expense – Old CGAAP

Appendix 2-CS
Depreciation and Amortization Expense

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013

Year 2013 Former CGAAP - CGAAP without the changes to the policies

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2013 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2013 Depreciation Expense (h) = (e) / (f)	2013 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (I)	Variance [2] (m) = (h) - (I)
1609	Distribution Station Equipment <50 kV - Capital Contributions Paid	$ -		$ -	$ 29,835	$ 14,918	30.00	3.33%	$ 497	$ 497	$ 0
1820	Distribution Station Equipment <50 kV	$ 466,497		$ 466,497	$ -	$ 466,497	30.00	3.33%	$ 15,550	$ 17,266	-$ 1,716
1830	Poles, Towers & Fixtures	$20,627,452		$ 20,627,452	$ 1,907,831	$ 21,581,368	25.00	4.00%	$ 863,255	$ 995,416	-$ 132,161
1835	Overhead Conductors & Devices	$13,556,975		$ 13,556,975	$ 1,249,008	$ 14,181,479	25.00	4.00%	$ 567,259	$ 612,066	-$ 44,807
1840	Underground Conduit	$ 1,366,196		$ 1,366,196	$ 456,855	$ 1,594,624	25.00	4.00%	$ 63,785	$ 65,486	-$ 1,701
1845	Underground Conductors & Devices	$ 7,702,253		$ 7,702,253	$ 749,544	$ 8,077,025	25.00	4.00%	$ 323,081	$ 336,723	-$ 13,642
1850	Line Transformers	$12,387,905		$ 12,387,905	$ 859,557	$ 12,817,684	25.00	4.00%	$ 512,707	$ 520,610	-$ 7,903
1855	Services (Overhead & Underground)	$ 2,683,092		$ 2,683,092	$ 240,643	$ 2,803,414	25.00	4.00%	$ 112,137	$ 112,750	-$ 613
1860	Meters	$ 3,034,122		$ 3,034,122	$ 30,060	$ 3,049,152	25.00	4.00%	$ 121,966	$ 126,744	-$ 4,778
1860	Meters (Smart Meters)	$ 3,724,761		$ 3,724,761	$ 118,390	$ 3,783,956	15.00	6.67%	$ 252,264	$ 243,126	$ 9,138
1905	Land	$ 127,139		$ 127,139	$ -	$ 127,139		0.00%	$ -	$ -	$ -
1612	Land Rights (Formally known as Account 1906)	$ 695,389		$ 695,389	$ -	$ 695,389	50.00	2.00%	$ 13,908	$ 20,720	-$ 6,812
1908	Buildings & Fixtures	$ 2,190,518		$ 2,190,518	$ -	$ 2,190,518	50.00	2.00%	$ 43,810	$ 51,715	-$ 7,905
1915	Office Furniture & Equipment (10 years)	$ 365,636	$ 136,065	$ 229,571	$ 5,000	$ 232,071	10.00	10.00%	$ 23,207	$ 23,021	$ 186
1920	Computer Equipment - Hardware	$ 585,095	$ 255,206	$ 329,889	$ 57,125	$ 358,452	5.00	20.00%	$ 71,690	$ 67,921	$ 3,769
1611	Computer Software (Formally known as Account 1925)	$ 2,765,069	$ 1,094,488	$ 1,670,581	$ 196,000	$ 1,768,581	5.00	20.00%	$ 353,716	$ 324,494	$ 29,222
1930	Transportation Equipment	$ 2,207,646	$ 597,615	$ 1,610,031	$ 247,281	$ 1,733,672	8.00	12.50%	$ 216,709	$ 206,206	$ 10,503
1940	Tools, Shop & Garage Equipment	$ 795,038	$ 227,949	$ 567,089	$ 35,685	$ 584,932	10.00	10.00%	$ 58,493	$ 59,581	-$ 1,088
1955	Communications Equipment	$ 68,074	$ 48,770	$ 19,304	$ -	$ 19,304	5.00	20.00%	$ 3,861	$ 3,860	$ 1
1995	Contributions & Grants	-$ 4,143,672		-$ 4,143,672	-$ 681,804	-$ 4,484,574	25.00	4.00%	-$ 179,383	-$ 171,665	-$ 7,718
etc.											
	Total	**$71,205,185**	**$ 2,360,093**	**$ 68,845,092**	**$ 5,501,010**	$ 71,595,597			$ 3,438,512	$ 3,616,537	-$ 178,025

Table 20
2013 Depreciation Expense – New CGAAP

Appendix 2-CT
Depreciation and Amortization Expense

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013

Year 2013 Revised CGAAP or ASPE - CGAAP or ASPE with the changes to the policies

Account	Description	Opening NBV as at Jan 1, 2013 [5] (a)	Additions (d)	Average Remaining Life of Opening NBV [4] (i)	Years (new additions only) [3] (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Depreciation Expense on Opening NBV (j) = (a) / (i)	Depreciation Expense on Additions [1] (h)=((d)*0.5)/(f)	2013 Depreciation Expense (k) = (j) + (h)	2013 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (k) - (l)	Depreciation Expense on 2013 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2013 Full Year Depreciation [6] (p) = (j) + (n) - (o)
1609	Distribution Station Equipment <50 kV - Capital Contributions Paid	$ -	$ 29,835		45.00	2.22%	$ -	$ 332	$ 332	$ 332	$ (1)	$ 663		$ 663
1820	Distribution Station Equipment <50 kV	$ 281,147		35.00	45.00	2.22%	$ 8,033	$ -	$ 8,033	$ 8,035	$ (2)	$ -		$ 8,033
1830	Poles, Towers & Fixtures - Wood Poles	$ 11,261,985	$ 1,907,831	42.00	50.00	2.00%	$ 268,143	$ 19,078	$ 287,221	$ 287,600	$ (379)	$ 38,157		$ 306,299
1830	Poles, Towers & Fixtures - Metal/Concrete Poles	$ 39,859		48.00	60.00	1.67%	$ 830	$ -	$ 830	$ 835	$ (5)	$ -		$ 830
1835	Overhead Conductors & Devices - Conductor	$ 8,881,160	$ 1,249,008	45.00	50.00	2.00%	$ 197,359	$ 12,490	$ 209,849	$ 210,754	$ (905)	$ 24,980		$ 222,339
1835	Overhead Conductors & Devices - Line Switches	$ 237,761		33.00	45.00	2.22%	$ 7,205	$ -	$ 7,205	$ 7,260	$ (55)	$ -		$ 7,205
1835	Overhead Conductors & Devices - Reclosers	$ 263,645		31.00	40.00	2.50%	$ 8,505	$ -	$ 8,505	$ 8,446	$ 59	$ -		$ 8,505
1840	Underground Conduit - Duct	$ 1,218,816	$ 456,855	48.00	50.00	2.00%	$ 25,392	$ 4,569	$ 29,961	$ 30,125	$ (164)	$ 9,137		$ 34,529
1845	Underground Conductors & Devices - Non-Duct	$ 3,257,904	$ 33,369	19.00	30.00	3.33%	$ 171,469	$ 556	$ 172,025	$ 173,968	$ (1,943)	$ 1,112		$ 172,581
1845	Underground Conductors & Devices - In Duct	$ 745,789	$ 639,620	29.00	40.00	2.50%	$ 25,717	$ 7,995	$ 33,712	$ 33,438	$ 274	$ 15,991		$ 41,707
1845	Underground Conductors & Devices - Switchgear	$ 32,098	$ 76,555	20.00	30.00	3.33%	$ 1,605	$ 1,276	$ 2,881	$ 2,915	$ (34)	$ 2,552		$ 4,157
1850	Line Transformers - Pole-Top	$ 5,495,958	$ 581,783	30.00	40.00	2.50%	$ 183,199	$ 7,272	$ 190,471	$ 188,586	$ 1,885	$ 14,545		$ 197,743
1850	Line Transformers - Padmount	$ 1,716,875	$ 216,524	34.00	40.00	2.50%	$ 50,496	$ 2,707	$ 53,203	$ 53,924	$ (721)	$ 5,413		$ 55,909
1850	Line Transformers - Step-Down (Rabbits)	$ 222,976	$ 61,250	34.00	40.00	2.50%	$ 6,558	$ 766	$ 7,324	$ 7,418	$ (94)	$ 1,531		$ 8,089
1850	Line Transformers - Spare Capital	$ 213,830				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1855	Services - Overhead	$ 690,071	$ 110,516	53.00	60.00	1.67%	$ 13,020	$ 921	$ 13,941	$ 13,931	$ 10	$ 1,842		$ 14,862
1855	Services - Underground	$ 1,162,577	$ 130,127	27.00	35.00	2.86%	$ 43,058	$ 1,859	$ 44,917	$ 44,340	$ 577	$ 3,718		$ 46,776
1860	Meters - Primary Metering Untis	$ 107,762	$ 9,480	16.00	20.00	5.00%	$ 6,735	$ 237	$ 6,972	$ 6,836	$ 136	$ 474		$ 7,209
1860	Meters - Interval Meters & Other Metering Equipment	$ 992,121	$ 20,580	5.00	15.00	6.67%	$ 198,424	$ 686	$ 199,110	$ 218,149	$ (19,039)	$ 1,372		$ 199,796
1860	Meters - Smart Meters	$ 2,967,100	$ 118,390	12.00	15.00	6.67%	$ 247,258	$ 3,946	$ 251,205	$ 247,073	$ 4,132	$ 7,893		$ 255,151
1860	Meters - Stranded Meters	$ 526,433		12.00	25.00	4.00%	$ 43,869	$ -	$ 43,869	$ 42,501	$ 1,368	$ -		$ 43,869
1860	Meters - Spare Capital	$ 94,676				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1905	Land	$ 127,139				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1612	Land Rights (Formally known as Account 1906)	$ 435,497		21.00	50.00	2.00%	$ 20,738	$ -	$ 20,738	$ 20,720	$ 18	$ -		$ 20,738
1908	Buildings & Fixtures	$ 1,722,750		33.00	50.00	2.00%	$ 52,205	$ -	$ 52,205	$ 51,715	$ 490	$ -		$ 52,205
1915	Office Furniture & Equipment (10 years)	$ 104,396	$ 5,000	5.00	10.00	10.00%	$ 20,879	$ 250	$ 21,129	$ 23,021	$ (1,892)	$ 500	$ 125	$ 21,254
1920	Computer Equipment - Hardware	$ 189,098	$ 57,125	3.00	5.00	20.00%	$ 63,033	$ 5,713	$ 68,745	$ 67,921	$ 824	$ 11,425	$ 7,390	$ 67,068
1611	Computer Software (Formally known as Account 1925)	$ 663,565	$ 196,000	2.00	5.00	20.00%	$ 331,783	$ 19,600	$ 351,383	$ 324,494	$ 26,889	$ 39,200	$ 24,199	$ 346,784
1930	Transportation Equipment - Bucket Trucks	$ 854,775	$ 207,000	10.00	12.00	8.33%	$ 85,478	$ 8,625	$ 94,103	$ 97,234	$ (3,132)	$ 17,250		$ 102,728
1930	Transportation Equipment - Pickups / Vans	$ 136,885	$ 40,281	4.00	8.00	12.50%	$ 34,221	$ 2,518	$ 36,739	$ 39,005	$ (2,266)	$ 5,035		$ 39,256
1930	Transportation Equipment - Trailers	$ 32,686		16.00	20.00	5.00%	$ 2,043	$ -	$ 2,043	$ 2,000	$ 43	$ -		$ 2,043
1940	Tools, Shop & Garage Equipment	$ 343,260	$ 35,685	6.00	10.00	10.00%	$ 57,210	$ 1,784	$ 58,994	$ 59,581	$ (587)	$ 3,569	$ 50	$ 60,729
1955	Communications Equipment	$ 10,132		3.00	5.00	20.00%	$ 3,377	$ -	$ 3,377	$ 3,860	$ (483)	$ -		$ 3,377
1995	Contributions & Grants - Wood Poles	$ (554,991)	$ (88,153)	44.00	50.00	2.00%	$ (12,613)	$ (882)	$ (13,495)	$ (13,528)	$ 33	$ (1,763)		$ (14,376)
1995	Contributions & Grants - O/H Conductor	$ (167,005)	$ (5,254)	45.00	50.00	2.00%	$ (3,711)	$ (53)	$ (3,764)	$ (3,758)	$ (6)	$ (105)		$ (3,816)
1995	Contributions & Grants - O/H Line Switches	$ (6,669)		40.00	45.00	2.22%	$ (167)	$ -	$ (167)	$ (167)	$ 0	$ -		$ (167)
1995	Contributions & Grants - O/H Reclosures	$ (5,838)		35.00	40.00	2.50%	$ (167)	$ -	$ (167)	$ (167)	$ 0	$ -		$ (167)
1995	Contributions & Grants - U/G Conduit - Duct	$ (237,607)	$ (116,303)	45.00	50.00	2.00%	$ (5,280)	$ (1,163)	$ (6,443)	$ (6,494)	$ 51	$ (2,326)		$ (7,606)
1995	Contributions & Grants - U/G Conductor - Non-Duct	$ (818,874)		24.00	30.00	3.33%	$ (34,120)	$ -	$ (34,120)	$ (34,702)	$ 582	$ -		$ (34,120)
1995	Contributions & Grants - U/G Conductor - In Duct	$ (183,911)	$ (310,010)	34.00	40.00	2.50%	$ (5,409)	$ (3,875)	$ (9,284)	$ (9,333)	$ 49	$ (7,750)		$ (13,159)
1995	Contributions & Grants - Pole TopTransformers	$ (488,076)	$ (31,658)	33.00	40.00	2.50%	$ (14,790)	$ (396)	$ (15,186)	$ (15,109)	$ (77)	$ (791)		$ (15,582)
1995	Contributions & Grants - Padmount Transformers	$ (125,178)	$ (78,787)	33.00	40.00	2.50%	$ (3,793)	$ (985)	$ (4,778)	$ (4,758)	$ (20)	$ (1,970)		$ (5,763)
1995	Contributions & Grants - Step-Down Transformers	$ (16,245)		33.00	40.00	2.50%	$ (492)	$ -	$ (492)	$ (490)	$ (2)	$ -		$ (492)
1995	Contributions & Grants - O/H Services	$ (109,377)	$ (20,126)	53.00	60.00	1.67%	$ (2,064)	$ (168)	$ (2,231)	$ (2,223)	$ (8)	$ (335)		$ (2,399)
1995	Contributions & Grants - U/G Services	$ (188,817)	$ (23,692)	28.00	35.00	2.86%	$ (6,743)	$ (338)	$ (7,082)	$ (7,056)	$ (26)	$ (677)		$ (7,420)
1995	Contributions & Grants - Primary Metering Units	$ (134,893)		16.00	20.00	5.00%	$ (8,431)	$ -	$ (8,431)	$ (8,431)	$ 0	$ -		$ (8,431)
1995	Contributions & Grants - Interval & Other Metering Equip	$ (22,219)	$ (1,158)	8.00	15.00	6.67%	$ (2,777)	$ (39)	$ (2,816)	$ (2,781)	$ (35)	$ (77)		$ (2,855)
1995	Contributions & Grants - Smart Meters	$ (76,530)	$ (6,663)	8.00	15.00	6.67%	$ (9,566)	$ (222)	$ (9,788)	$ (9,667)	$ (121)	$ (444)		$ (10,010)
etc.														
	Total	**$ 41,894,496**	**$ 5,501,010**				**$ 2,067,717**	**$ 95,059**	**$ 2,162,776**	**$ 2,157,353**	**$ 5,423**	**$ 190,118**	**$ 31,764**	**$ 2,226,071**

Table 21
2014 Depreciation Expense – New CGAAP

Appendix 2-CU
Depreciation and Amortization Expense

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013

Year 2014 Revised CGAAP or ASPE - CGAAP or ASPE with the changes to the policies

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2014 Depreciation Expense [1] (h)=2013 Full Year Depreciation + ((d)*0.5)/(f)	2014 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1609	Distribution Station Equipment <50 kV - Capital Contributions Paid	$ 441,675	45.00	2.22%	**$ 5,571**	$ 5,571	**$ (1)**
1820	Distribution Station Equipment <50 kV	$ 5,000	45.00	2.22%	**$ 8,088**	$ 8,091	**$ (3)**
1830	Poles, Towers & Fixtures - Wood Poles	$1,615,483	50.00	2.00%	**$ 322,454**	$ 322,835	**$ (381)**
1830	Poles, Towers & Fixtures - Metal/Concrete Poles		60.00	1.67%	**$ 830**	$ 835	**$ (5)**
1835	Overhead Conductors & Devices - Conductor	$1,117,956	50.00	2.00%	**$ 233,519**	$ 234,423	**$ (904)**
1835	Overhead Conductors & Devices - Line Switches	$ 15,900	45.00	2.22%	**$ 7,382**	$ 7,437	**$ (55)**
1835	Overhead Conductors & Devices - Reclosers		40.00	2.50%	**$ 8,505**	$ 8,446	**$ 59**
1840	Underground Conduit - Duct	$ 641,971	50.00	2.00%	**$ 40,949**	$ 41,113	**$ (164)**
1845	Underground Conductors & Devices - Non-Duct		30.00	3.33%	**$ 172,581**	$ 174,523	**$ (1,942)**
1845	Underground Conductors & Devices - In Duct	$ 570,260	40.00	2.50%	**$ 48,836**	$ 48,562	**$ 274**
1845	Underground Conductors & Devices - Switchgear	$ 41,600	30.00	3.33%	**$ 4,850**	$ 4,884	**$ (34)**
1850	Line Transformers - Pole-Top	$ 499,028	40.00	2.50%	**$ 203,981**	$ 202,097	**$ 1,884**
1850	Line Transformers - Padmount	$ 178,699	40.00	2.50%	**$ 58,143**	$ 58,864	**$ (721)**
1850	Line Transformers - Step-Down (Rabbits)	$ 29,250	40.00	2.50%	**$ 8,455**	$ 8,550	**$ (95)**
1850	Line Transformers - Spare Capital			0.00%	**$ -**		**$ -**
1855	Services - Overhead	$ 113,572	60.00	1.67%	**$ 15,809**	$ 15,798	**$ 11**
1855	Services - Underground	$ 136,725	35.00	2.86%	**$ 48,730**	$ 48,152	**$ 578**
1860	Meters - Primary Metering Untis	$ 77,540	20.00	5.00%	**$ 9,148**	$ 9,012	**$ 136**
1860	Meters - Interval Meters & Other Metering Equipment	$ 34,660	15.00	6.67%	**$ 200,952**	$ 192,515	**$ 8,437**
1860	Meters - Smart Meters	$ 133,025	15.00	6.67%	**$ 259,585**	$ 252,371	**$ 7,214**
1860	Meters - Spare Capital			0.00%	**$ -**		**$ -**
1905	Land			0.00%	**$ -**		**$ -**
1612	Land Rights (Formally known as Account 1906)		50.00	2.00%	**$ 20,738**	$ 20,720	**$ 18**
1908	Buildings & Fixtures		50.00	2.00%	**$ 52,205**	$ 51,730	**$ 475**
1915	Office Furniture & Equipment (10 years)	$ 5,000	10.00	10.00%	**$ 21,504**	$ 22,044	**$ (540)**
1920	Computer Equipment - Hardware	$ 109,344	5.00	20.00%	**$ 78,002**	$ 65,786	**$ 12,216**
1611	Computer Software (Formally known as Account 1925)	$ 280,645	5.00	20.00%	**$ 374,848**	$ 221,292	**$ 153,556**
1930	Transportation Equipment - Bucket Trucks		12.00	8.33%	**$ 102,728**	$ 105,859	**$ (3,132)**
1930	Transportation Equipment - Pickups / Vans	$ 218,400	8.00	12.50%	**$ 52,906**	$ 55,172	**$ (2,266)**
1930	Transportation Equipment - Trailers		20.00	5.00%	**$ 2,043**	$ 2,000	**$ 43**
1940	Tools, Shop & Garage Equipment	$ 67,250	10.00	10.00%	**$ 64,091**	$ 56,600	**$ 7,491**
1955	Communications Equipment		5.00	20.00%	**$ 3,377**	$ 3,861	**$ (484)**
1995	Contributions & Grants - Wood Poles	$ (38,153)	50.00	2.00%	**$ (14,758)**	$ (14,792)	**$ 34**
1995	Contributions & Grants - O/H Conductor	$ (5,254)	50.00	2.00%	**$ (3,869)**	$ (3,863)	**$ (6)**
1995	Contributions & Grants - O/H Line Switches		45.00	2.22%	**$ (167)**	$ (167)	**$ 0**
1995	Contributions & Grants - O/H Reclosures		40.00	2.50%	**$ (167)**	$ (167)	**$ 0**
1995	Contributions & Grants - U/G Conduit - Duct	$ (16,303)	50.00	2.00%	**$ (7,769)**	$ (7,820)	**$ 51**
1995	Contributions & Grants - U/G Conductor - Non-Duct		30.00	3.33%	**$ (34,120)**	$ (34,702)	**$ 582**
1995	Contributions & Grants - U/G Conductor - In Duct	$ (166,761)	40.00	2.50%	**$ (15,244)**	$ (15,293)	**$ 49**
1995	Contributions & Grants - Pole TopTransformers	$ (31,658)	40.00	2.50%	**$ (15,977)**	$ (15,900)	**$ (77)**
1995	Contributions & Grants - Padmount Transformers	$ (44,297)	40.00	2.50%	**$ (6,317)**	$ (6,297)	**$ (20)**
1995	Contributions & Grants - Step-Down Transformers		40.00	2.50%	**$ (492)**	$ (490)	**$ (2)**
1995	Contributions & Grants - O/H Services	$ (19,639)	60.00	1.67%	**$ (2,563)**	$ (2,555)	**$ (8)**
1995	Contributions & Grants - U/G Services	$ (24,179)	35.00	2.86%	**$ (7,766)**	$ (7,740)	**$ (26)**
1995	Contributions & Grants - Primary Metering Units		20.00	5.00%	**$ (8,431)**	$ (8,431)	**$ 0**
1995	Contributions & Grants - Interval & Other Metering Equip	$ (1,672)	15.00	6.67%	**$ (2,910)**	$ (2,875)	**$ (35)**
1995	Contributions & Grants - Smart Meters	$ (6,149)	15.00	6.67%	**$ (10,215)**	$ (10,094)	**$ (121)**
etc.				0.00%			
	Total	**$5,978,918**			**$ 2,300,042**	**$ 2,117,957**	**$ 182,085**

Total Depreciation expense to be included in the test year revenue requirement **$ 2,300,042**

In Table 19 “2012 Depreciation Expense – Old CGAAP”, the variance calculated in the OEB Appendix 2-CR in the category “1860 – Meters (Smart Meters)” is on account of the smart meter disposition approved November 1, 2012 as discussed in this Tab before the tables.

In Table 21 “2014 Depreciation Expense – New CGAAP”, the variance calculated in the OEB Appendix 2-CU in the category “1611 – Computer Software (Formerly known as Account 1925)” is on account of the number of assets in this category that will be fully depreciated at the beginning of 2014 and will not attract a full year of depreciation. HCHI is able to calculate and forecast depreciation in its Great Plains financial software, specifically the Fixed Asset module, in order to only record the depreciation for the exact number of days each asset will be depreciated for in the 2014 Test Year. HCHI’s calculation of depreciation expense of $2,117,957, prior to the CDM-OPA reallocation amounts, is a more accurate calculation than the $2,300,042 in Table 21 above and should be the amount included in the 2014 Test Year revenue requirement less the CDM-OPA allocated costs of $3,969.

USEFUL LIFE ACCOUNTING CHANGE UNDER CGAAP

Prior to 2013, HCHI followed Canadian Generally Accepted Accounting Principles ("CGAAP") for the purpose of recording capital assets. HCHI recorded General and Administrative assets by each asset based on the accounting class of the asset and the in service date. HCHI recorded Distribution Plant assets as pooled assets based on major accounting classes in the month of, and specific capital projects on the date of, in service. In 2013, HCHI made an accounting change under CGAAP to the useful lives of asset classes as instructed by the Board in its letter dated July 17, 2012. The useful lives change was based on the Depreciation Study for Use by Electricity Distributors (EB-2010-0178), ("the Kinectrics Report"), prepared by Kinectrics on behalf of the OEB. HCHI reviewed this study as well as applied its own experience to determine revised useful lives for all capital assets.

HCHI completed sufficient detailed accounting work in order to make these accounting changes while remaining under CGAAP as permitted by the Board's letter. As indicated in Exhibit 1, HCHI will not be transitioning to IFRS until January 1, 2015. HCHI determined that some asset components identified by Kinectrics were materially insignificant and would not be recognized as separate asset components under CGAAP.

HCHI revised the useful lives of assets to correspond with the typical useful lives ("TUL") of assets in the Kinectrics report with three exceptions as noted at the bottom of Table 16 above. In summary, they are as follows:

1. Wood Poles – Useful life of 50 years. Kinectrics Report TUL = 45 years. HCHI experiences an average replacement at 49 years. The Kinectrics Asset Condition Assessment ("ACA") prepared for HCHI shows a 20% failure rate at 45 years and a 90% failure rate at 75 years.

2. Overhead Conductor – Useful life of 50 years. Kinectrics Report TUL = 60 years. HCHI typically replaces the overhead conductor at the same time as the wood pole.

3. Interval Meters, CTs and PTs, and Meter Cabinets – Useful life of 15 years. Kinectrics Report range 25 to 50 years. HCHI assigned same TUL as a Smart Meter. These types of assets were not part of the ACA.

HCHI's asset management policies include the replacement of immaterial and insignificant components at the same time as the significant component. HCHI will review the asset class useful lives on a periodic basis to determine whether any changes are necessary.

All General and Administrative assets from accounts 1900 to 1980 will continue to be separately identified assets. However, HCHI was required to further breakout account 1930 Transportation equipment for Bucket Trucks, Pickups / Vans, and Trailers as the Kinectrics Report assigned different TULs for these categories.

TAXES (PILS, CAPITAL TAX and PROPERTY TAXES)

Income Tax, Large Corporation Tax and Ontario Capital Taxes

Under Section 93 of the *Electricity Act, 1998*, as amended, HCHI makes payments in lieu ("PILS") of corporate taxes. These payments are calculated in accordance with the rules for computing taxable income, taxable capital and other relevant amounts contained in the *Income Tax Act (Canada)* and the *Corporations Tax Act (Ontario)*, as modified by the *Electricity Act, 1998*, and related regulations. The Applicant does not pay Section 89 proxy taxes, and is exempt from the payment of income and capital taxes under the *Income Tax Act (Canada)* and the Ontario *Corporations Tax Act*.

Detailed PILS/Tax Calculations

HCHI is proposing a recovery of 2014 Test Year taxes totaling $100,492. HCHI has calculated the 2014 Test Year PILS/Tax Provision in accordance with the Board's tax methodology utilizing the OEB's Tax Model, filed as Appendix B to this Exhibit and as a live Excel model with this Application. HCHI has used the tax rates and exemptions and capital cost allowance rates as provided in the Board's Tax Model as well as verified this information for the appropriateness and accuracy with its external auditors (i.e. integrity check). A summary of the tax rates and exemptions for 2012, 2013 and 2014 is set out in the following Table 22. The details of the undepreciated capital cost ("UCC"), capital cost allowance ("CCA") and the cumulative eligible capital ("CEC") amounts for the 2013 Bridge Year and 2014 Test Year are provided as continuity schedules in the following Table 23.

Taxable income calculations for each of the 2010 Board Approved, 2012 Actual, 2013 Bridge Year and 2014 Test Year are provided in the following Table 24. The resulting PILs/Tax Provision calculation for each of these years is provided in the following Table 25. The 2012 Actual amounts are as reported in the Federal "T2 Corporation Income Tax Return" and Ontario "CT23 Corporations Tax and Annual Return" as filed for the year ended December 31, 2012 – copies of which are provided in Appendix C. The

income tax provision reported in the 2012 audited financial statements (Exhibit 1 – Tab 3 – Appendix D) is based on an estimate and will differ from the payable amounts per the income tax returns. The difference between the estimated provision and actual payable will be reflected in the 2013 audited financial statements.

Table 22
Tax Rates and Exemptions

Federal & Provincial Tax Rates As of June 20, 2012	**Notes**	**Effective January 1, 2012**	**Effective January 1, 2013**	**Effective January 1, 2014**
Federal income tax				
General corporate rate		38.00%	38.00%	38.00%
Federal tax abatement		-10.00%	-10.00%	-10.00%
Adjusted federal rate		28.00%	28.00%	28.00%
Rate reduction		-13.00%	-13.00%	-13.00%
Federal Tax Rate		**15.00%**	**15.00%**	**15.00%**
Ontario income tax		11.50%	11.50%	11.50%
Federal & Ontario Small Business				
Federal Small Business Threshold		500,000	500,000	500,000
Ontario Small Business Threshold		500,000	500,000	500,000
Federal Small Business Rate		11.000%	11.000%	11.000%
Ontario Small Business Rate	1	**4.500%**	**4.500%**	**4.500%**
Effective Ontario Tax Rate	2	**9.79%**	**9.14%**	**5.03%**
Effective Federal Tax Rate	3	**15.51%**	**15.00%**	**15.00%**
Combined Federal and Ontario	4	**25.30%**	**24.14%**	**20.03%**

NOTES:
1. Ontario Small Business Rate of 4.50% applicable to HCHI on first $500,000.
2. Effective Ontario Tax Rate calculated in OEB PILs model based on reduced rate for first $500,000 and full rate for balance of income.
3. Effective Federal Tax Rate for 2012 Historical Actual takes into consideration the Investment Income Tax.
4. Combined Federal and Ontario tax rate calculated in OEB PILs model of "Federal tax rate" in each year and "Effective Ontario Tax Rate" applicable to each year.

Table 23
UCC, CCA and CEC Continuity Schedules

2013 BRIDGE YEAR

Class	Class Description	UCC Bridge Year Opening Balance	Additions	Disposals	UCC Before 1/2 Yr Rule	1/2 Year Rule {1/2 Addn's Less Disposals}	Reduced UCC	Rate %	Bridge Year CCA	UCC End of Bridge Year
1	Distribution System - post 1987	$ 22,109,558	$ -	$ -	$ 22,109,558	$ -	$ 22,109,558	4%	$ 884,382	$ 21,225,176
8	General Office/Stores Equip	$ 926,749	$ 40,685	$ -	$ 967,434	$ 20,343	$ 947,092	20%	$ 189,418	$ 778,016
10	Computer Hardware / Vehicles	$ 667,015	$ 247,281	$ -	$ 914,296	$ 123,641	$ 790,656	30%	$ 237,197	$ 677,099
17	Parking Lots, sidewalks	$ 48,704	$ -	$ -	$ 48,704	$ -	$ 48,704	8%	$ 3,896	$ 44,808
45	Computers & Systems Software (post Mar 22, 2004)	$ 3,326	$ -	$ -	$ 3,326	$ -	$ 3,326	45%	$ 1,497	$ 1,829
46	Data Network Infrastructure Equipment (post Mar 22,2004)	$ 97	$ -	$ -	$ 97	$ -	$ 97	30%	$ 29	$ 68
47	Distribution System (post February 2005)	$ 21,143,554	$ 4,930,084	$ (1,666,572)	$ 24,407,066	$ 1,631,756	$ 22,775,310	8%	$ 1,822,025	$ 22,585,041
50	Computers & Systems Software (post Mar 18, 2007)	$ 114,725	$ 253,125	$ -	$ 367,850	$ 126,563	$ 241,288	55%	$ 132,708	$ 235,142
1	Buildings (post March 18, 2007)	$ 63,446		$ -	$ 63,446	$ -	$ 63,446	6%	$ 3,807	$ 59,639
	UCC and CCA - TOTAL	**$ 45,077,174**	**$ 5,471,175**	**$ (1,666,572)**	**$ 48,881,777**	**$ 1,902,302**	**$ 46,979,476**		**$ 3,274,959**	**$ 45,606,818**

		CEC Bridge Year Opening Balance	Additions at 100%		CEC Before Reduction for Additions	Reduction of 25% for Additions	CEC Balance prior Current Year Deduction	Rate %	Bridge Year CEC Deduction	CEC Bridge Year Closing Balance
CEC	**Cumulative Eligible Capital**	**$ 221,932**	**$ 29,835**	**$ -**	**$ 251,767**	**$ 7,459**	**$ 244,308**	7%	**$ 17,102**	**$ 227,207**

Table 23 (continued)
UCC, CCA and CEC Continuity Schedules

2014 TEST YEAR

Class	Class Description	UCC Test Year Opening Balance	Additions	Disposals	UCC Before 1/2 Yr Rule	1/2 Year Rule {1/2 Addn's Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	$ 21,225,176	$ -	$ -	$ 21,225,176	$ -	$ 21,225,176	4%	$ 849,007	$ 20,376,169
8	General Office/Stores Equip	$ 778,016	$ 72,250	$ -	$ 850,266	$ 36,125	$ 814,141	20%	$ 162,828	$ 687,438
10	Computer Hardware / Vehicles	$ 677,099	$ 218,400	$ -	$ 895,499	$ 109,200	$ 786,299	30%	$ 235,890	$ 659,609
17	Parking Lots, sidewalks	$ 44,808	$ -	$ -	$ 44,808	$ -	$ 44,808	8%	$ 3,585	$ 41,223
45	Computers & Systems Software (post Mar 22, 2004)	$ 1,829	$ -	$ -	$ 1,829	$ -	$ 1,829	45%	$ 823	$ 1,006
46	Data Network Infrastructure Equipment (post Mar 22,2004)	$ 68	$ -	$ -	$ 68	$ -	$ 68	30%	$ 20	$ 48
47	Distribution System (post February 2005)	$ 22,585,041	$ 4,856,604	$ -	$ 27,441,645	$ 2,428,302	$ 25,013,343	8%	$ 2,001,067	$ 25,440,578
50	Computers & Systems Software (post Mar 18, 2007)	$ 235,142	$ 389,989	$ -	$ 625,131	$ 194,995	$ 430,137	55%	$ 236,575	$ 388,556
1	Buildings (post March 18, 2007)	$ 59,639	$ -	$ -	$ 59,639	$ -	$ 59,639	6%	$ 3,578	$ 56,061
	UCC and CCA - TOTAL	**$ 45,606,818**	**$ 5,537,243**	**$ -**	**$ 51,144,061**	**$ 2,768,622**	**$ 48,375,440**		**$ 3,493,374**	**$ 47,650,687**

		CEC Bridge Year Opening Balance	Additions at 100%		CEC Before Reduction for Additions	Reduction of 25% for Additions	CEC Balance prior Current Year Deduction	Rate %	Bridge Year CEC Deduction	CEC Bridge Year Closing Balance
CEC	**Cumulative Eligible Capital**	**$ 227,207**	**$ 441,675**	**$ -**	**$ 668,882**	**$ 110,419**	**$ 558,463**	7%	**$ 39,092**	**$ 519,371**

Table 24
Taxable Income

`	Historic 2010 Board Approved	Historic 2012 "Actual"	Bridge 2013 Forecast	Test 2014 Forecast
Income Before PILs/Taxes	**$ 1,584,479**	**$ 781,585**	**$ 2,593,699**	**$ 1,932,410**
Additions:				
Amortization of tangible assets	$ 2,817,053	$ 3,940,606	$ 2,157,353	$ 2,117,957
Loss on disposal of assets	-	-	-	-
Taxable Capital Gains	-	53,282	-	-
Non-deductible meals and entertainment expense	9,647	9,032	9,032	9,032
Financing fees deducted in books	3,235	-	-	
Prior year apprenticeship job creation tax credit	4,000	-	350	2,000
Ontario Specified Tax Credits	44,342	28,167	19,000	26,000
Regulatory Liabilities 2012 Excluding Capital	-	2,106,320	-	-
Provision for Income Taxes - Current / Future	-	162,578	-	-
Total Additions	**$ 2,878,277**	**$ 6,299,985**	**$ 2,185,735**	**$ 2,154,989**
Deductions:				
Gain on disposal of assets per financial statements	$ 25,000	$ 112,536	$ 5,603	$ 13,940
Capital cost allowance from Schedule 8	2,663,377	3,220,597	3,274,959	3,493,374
Cumulative eligible capital deduction from Schedule 10 CEC	19,314	16,705	17,102	39,092
Accumulated Amortization of Regulatory Assets 2011	-	489,338	-	-
Regulatory Liabilities 2011 Excluding Capital	-	1,154,609	-	-
Apprenticship Training & Co-operative Education Investment Tax Credits	-	38,743	-	-
Total Deductions	**$ 2,707,691**	**$ 5,032,528**	**$ 3,297,664**	**$ 3,546,406**
REGULATORY TAXABLE INCOME	**$ 1,755,065**	**$ 2,049,042**	**$ 1,481,770**	**$ 540,993**

Table 25
PILS/Tax Provision Calculations

	HISTORIC		HISTORIC		BRIDGE YEAR		TEST YEAR	
	2010 Board Approved		2012 "Actual"		2013 Forecast		2014 Forecast	
Taxable Income		**$ 1,755,065**		**$ 2,049,042**		**$ 1,481,770**		**$ 540,993**
Combined Tax Rate								
Ontario Tax Rate	11.79%		9.79%		9.14%		5.03%	
Federal tax rate	18.00%		15.51%		15.00%		15.00%	
Combined tax rate	29.79%		25.30%		24.14%		20.03%	
Total Income Taxes		$ 522,820		$ 518,475		$ 357,669		$ 108,363
Tax Credits								
Investment Tax Credits		$ -		$ 350		$ 2,000		$ 2,000
Miscellaneous Tax Credits		$ 44,342		$ 24,659		$ 19,000		$ 26,000
Total Tax Credits		$ 44,342		$ 25,009		$ 21,000		$ 28,000
Income Tax Provision		$ 478,478		$ 493,466		$ 336,669		$ 80,363
Income Tax Provision Gross Up	70.21%	$ 203,010			75.86%	$ 107,122	79.97%	$ 20,129
Income Tax (grossed-up)		**$ 681,488**		**$ 493,466**		**$ 443,791**		**$ 100,492**
Ontario Capital Tax (not grossed-up)		**$ 18,911**		**$ -**		**$ -**		**$ -**
PILS/TAX PROVISION FOR YEAR		**$ 700,399**		**$ 493,466**		**$ 443,791**		**$ 100,492**
Ontario Capital Tax								
Rate Base		$ 40,215,213						
Less: Exemption		$ 15,000,000						
Taxable Capital		$ 25,215,213						
OCT Rate	0.075%							
Ontario Capital Tax		$ 18,911						

HCHI has vetted its 2014 PILs/tax provision calculations as contained in the Board's PILs model through its external auditors (i.e. integrity check), who have pointed out that the PILs model does not calculate the gross up at the proper tax rate. The Ontario Small Business Deduction should not be factored into the gross-up as this portion of the taxable income is in excess of $500,000. The gross-up should use the top corporate rate of 26.5%. This results in approximately an $8,600 difference in HCHI's "proposed" Revenue Requirement. In the meantime, HCHI has used the Board's model "as is", but does not agree with the rate used in the calculation of the gross-up to arrive at the PILs / Tax Provision for the 2014 Test Year.

Property Taxes

Property taxes paid in 2012, and forecast to be paid in the 2013 Bridge Year and the 2014 Test Year are set out in the following Table 26.

Table 26
Property Taxes

	2012 Actual Year	2013 Bridge Year	2014 Test Year
Property Taxes (Paid to Municipality)			
Service Centre - 1 Greendale Drive, Caledonia	$ 37,518	$ 38,643	$ 39,483
Selkirk North Distribution Station - 71 Selkirk St., Caledonia	$ 558		
Selkirk South Distribution Station - 112 Selkirk St., Caledonia	$ 1,382	$ 1,423	$ 2,724
Dunnville Hydro Yard - 134 Forest St. E., Dunnville	$ 873	$ 899	$ 940
Nanticoke Distribution Station - Walpole Con E	$ 489		
Jarvis Distribution Station - 1423 Haldimand Road 55	$ 581	$ 598	$ 1,000
Canfield Distribution Station - 105 Haldimand Hwy #56	$ 1,143	$ 1,217	$ 1,315
Decewsville Distribution Station - 2283 River Rd	$ 697	$ 718	$ 685
Decewsville Regulating Station - 315 Decewsville Rd	$ 1,943	$ 2,001	$ 2,367
	$ 45,184	$ 45,499	$ 48,514
PILS - Property Taxes (Paid to OEFC)	$ 2,690	$ 1,609	$ 295
Less: OPA-CDM Allocable Costs	$ (675)	$ (707)	$ (699)
Total Property Taxes	**$ 47,199**	**$ 46,401**	**$ 48,110**

The changes in property taxes between the 2012 Actual, 2013 Bridge Year and 2014 Test Year is modest and primarily the result of decreases to certain property assessment values, with offsetting increases in municipal property tax rates in the order of 2.5% annually.

Haldimand County Hydro	**POLICY**		
Section:	**Administrative - Finance**	**Section No.:**	**3.3**
Policy:	**Purchasing Policy**	**Policy No.:**	**3.3.1**
Issued:	**August 1, 2001**	**Revised:**	**Page 1 of 5**

The purpose of the policy is to establish regulations and guidelines to ensure the most cost-effective methods are used to purchase and dispose of goods and services and to outline the authority for incurring expenditures.

The purchasing expenditures and tendering policies apply to purchases of all types of goods, works and services by Haldimand County Hydro Inc., other than the borrowing and investing of money.

It shall be the policy of Haldimand County Hydro Inc. to ensure that all works or projects contracted or all materials or supplies purchased for the Corporation are done so at acceptable standards and at the most reasonable cost possible.

Formal tendering shall be considered for all purchases of services or supplies and materials except where:
more simplified, competitive quotation may be more appropriate or suitable;

(i) the expenditures of funds are within the limits established under the Corporation purchasing policy.
(ii) specific Board approval to dispense with the formal tendering process is granted.

1. Definitions

"Approved Budget" means the budget approved by the Corporation and any amendments thereto.

"Blanket Order" means the agreement wherein a vendor will sell certain items to the Corporation for an agreed period of time at certain terms.

"Board of Directors" means the Board of Directors of Haldimand County Hydro Inc.

"Capital Expenditures" means those expenditures identified by the Corporation in annual budget estimates in the "Capital" portion of the budget.

"Chief Executive Officer" means the Chief Executive Officer (C.E.O) of Haldimand County Hydro Inc.

"Emergency Purchase" means a purchase made in a crisis situation where immediate action is required to prevent the possible loss of life or property.

"Generic" means that no specific brand or name shall be included as part of the specification unless such a brand or name is required to identify the intent of a purchase, order or proposal.

"Invoice Approval Stamp" means a stamp prescribed by the Finance Department to ensure required approvals are applied to an invoice.

"Manager" means one of the following: Finance Manager, Consumer Service Manager, Engineering Manager and Operations Manager.

"Negotiation Method" means an acquisition method whereby the Corporation may confer with one or more vendors and award a contract without using competitive acquisition methods such as tender or quotations.

"Purchasing Agent" means the Purchasing/Stores Clerk.

"Purchasing Designate" means a person designated by a Manager to exercise responsibilities of that Manager with respect to this policy.

"Quotation" means a written offer to sell or a "bid" obtained from selected suppliers to supply stipulated goods or services at a particular price.

"Services" means items such as telephone, gas, water, hydro, janitorial and cleaning services, consultant services, legal surveys, medical and related services, insurance, leases for grounds, buildings, office or other space required by the Corporation and the rental, repair or maintenance of equipment, machinery, or other personal and real property.

"Small Order Purchases" means the purchase of goods and services up to an amount not exceeding $5,000.00.

"Supplies" means goods, wares, merchandise, material and equipment.

"Tender" means a formal written offer submitted to the Corporation by any company or member of the public in response to an invitation to supply the stipulated goods or services at a particular price.

"Treasurer" means the Finance Manager of the Corporation.

"Vendor" means any person or enterprise supplying goods or services to the Corporation.

2. Authority and Responsibilities

2.1 Managers and Supervisors of the Corporation are given the authority to make purchases of goods and services for the Corporation within specified limits set out in this policy.

2.2 A Manager may appoint a Purchasing Designate, using the form prescribed by the Engineering Department, to exercise any or all responsibilities assigned to that Manager by this policy. Any such delegation shall be in writing and shall include notification to the Finance Department.

2.3 A Manager shall be responsible for approval of all accounts within his or her department.

2.4 A Manager shall ensure that capital expenditures in an amount exceeding $50,000.00 in the annual estimates receive prior Corporation approval.

2.5 A Purchasing Agent of the Corporation is given the authority to make purchases of goods for the Corporation within specified limits set out in this policy.

2.6 Resolutions approving budget amendments, capital expenditures or special appropriations shall reference the purpose of the expenditures, cost estimates or expenditure limitations. Manager reports recommending budget amendments, capital expenditures or special appropriations shall be approved by the CEO prior to presentation to the Board of Directors.

3. Small Order Purchases

3.1 Supervisors are hereby authorized to make purchases of goods and services under $500.00 from such vendor and upon such terms and conditions, as the Supervisor deems appropriate, for stock items.

Managers are hereby authorized to make purchases of goods and services under $5000.00 from such vendors and upon such terms and conditions, as the Manager deems appropriate, for stock items.

4. **Quotation Purchases**

A Purchasing Agent is hereby authorized to make purchases under $500.00 for stock items and under $150 for non-stock items from such vendors and upon such terms and conditions, as the Purchasing Agent deems appropriate. Two (2) verbal quotations are acceptable for purchases under $500.00.

A Supervisor is hereby authorized to make purchases for amounts exceeding $500.00 but less than $5,000.00 from such vendors and upon such terms and conditions, as the Supervisor deems appropriate, subject to obtaining at least two (2) written quotations, where possible.

4.3 A Manager is hereby authorized to make Quotation Purchases for amounts exceeding $5,000.00 but less than $50,000.00 from such vendor and upon such terms and conditions as the Manager deems advisable, subject to obtaining at least two (2) written quotations, where possible.

4.4 Quotations must be submitted by fax, mail or personal delivery and shall be identified as a quotation for a specific work or project.

4.5 When the preferred Quotation (i) exceeds the appropriate budget; or (ii) exceeds $50,000.00, a Manager shall refer the Quotation results to the CEO for direction, Section 6 below shall apply.

5. **Purchase Orders**

5.1 The Purchasing Agent shall utilize purchase orders in all cases. Supervisors shall utilize purchase orders where the costs of individual goods or services exceed $500.00 and Managers shall utilize purchase orders where the costs of individual goods and services exceed $5,000.00. Purchase order numbers shall be issued in numeric blocks by the Engineering Department and shall be administered in each respective Department.

5.2 Managers shall code each purchase order with the appropriate expenditure account number.

5.3 Purchase Orders shall be in hard copy. A printed copy of the purchase order in standard format shall be sent by the Engineering Department.
The Engineering Department will develop and maintain standard format and numbering sequence.

5.4 Upon receipt of goods, the Manager or designate shall check shipment with purchase order and advise the Finance Department of any discrepancies.

6. **Tendering**

6.1 The Corporation shall participate where possible and practical with cooperative or bulk tendering where such is advantageous to the Corporation. As such, staff will consider conjoining with government agencies or utilities for cooperative or bulk tendering. It is required in this section that a tendering process or policy of another entity which the Corporation will conjoin with, to be in place which is similar and has a similar effect as this overall tendering policy.

6.2 Tendering shall apply to the purchase of all types of goods, works and services (except professional services) where the estimated cost is expected to exceed $50,000.00.

6.3 Notwithstanding the above, adherence to this tendering policy is not required with respect to the purchase of electricity or to a transaction specifically authorized by resolution of the Corporation to be exempt from this tendering policy.

6.4 Tender shall be called by invitation or by public advertisement.

6.5 All Tenders shall include the provision “the lowest bid or any bid will not be necessarily be accepted”.

6.6 All Tenders shall close at 3:00 P.M. Haldimand County time on the date specified in the invitation or advertisement. The department Manager and the Purchasing Agent will open quotations envelopes, the date and time of which will be specified in the Invitation Quote. Only staff and representatives of firms, under the discretion of the department Manager, submitting quotations may attend the opening.

6.7 A record of the tendered prices will be noted together with the list of tenders.

6.8 Tenders will be referred to the appropriate Manager for review.

6.9 Where Tendering is not practical, the limitations and conditions of section 8 below shall apply.

7. **Blanket Orders**

7.1 Blanket Orders may be issued as necessary following the Tendering or Quotation process as set out in this policy.

7.2 Blanket Orders shall be issued for a period not exceeding one year.

7.3 In the case of equipment repairs and equipment rentals for transaction not exceeding $50,000.00, a Manager is authorized to consider ability, quality or workmanship, service, availability, overall performance and experience, in addition to cost and may do so without first obtaining quotations.

8. **Requests for Proposals**

A Manager may use a request for proposal in place of a Tender when goods or services cannot be specifically stipulated or when alternative methods are being sought to perform certain functions or services.

In the case of requests for proposals, evaluation criteria may be issued to perspective applicants.

9. **Emergency Purchases**

A Manager, in the absence of the CEO, is hereby authorized to make Emergency Purchases that exceed the specified limits as set out in this policy, without the CEO approval. A Manager who has made an Emergency Purchase shall present a report to the CEO within three days.

Emergency Purchases shall be reported to the Board of Directors.

10. **Purchase by Negotiating**

A Manager may, under direction of the CEO, purchase by negotiating with one or more vendors. In such a case, the requirement for inviting Tenders and Quotations may be waived under the following conditions:

(i) Where there is only one source of supply for the goods and services.

(ii) Where all bids received fail to meet the specification and/or tender terms, conditions and budget and it is impractical to recall Tenders or Quotations.

The methods of negotiations shall be those accepted as standard negotiating practice and shall employ fair and ethical practices. The information pertinent to and results of all such negotiations shall be reported to the CEO.

11. **Exceptions**

A Manager may request exemption from any or all of the purchasing methods outlined in this policy by submission of a request to the CEO. Such exemption will be reported to the Board of Directors.

12. **General Provisions**

Neither the CEO nor any Manager or other employee shall divide, stagger or alter any contract or purchase to avoid any requirement of this policy.

No employee or Director of the Corporation shall purchase or offer to purchase on behalf of the Corporation any goods or services except in accordance with the policy.

No personal purchases shall be made by the Corporation for Directors or employees.

The purchase of goods and services from firms located within Haldimand County shall be encouraged whenever possible, on the basis of all other selection criteria being equal.

Performance evaluations may be undertaken on suppliers and providers of service.

The CEO and Managers shall ensure that in all purchases, price and past performance shall be the prime selection criteria provided all specifications are met.



Income Tax/PILs Workform for 2014 Filers

Version 2.0

Utility Name	Haldimand County Hydro Inc.
Assigned EB Number	EB-2013-0134
Name and Title	Jacqueline A. Scott, Finance Manager
Phone Number	905-765-5211 ext.2237
Email Address	jscott@hchydro.ca
Date	15-Nov-13
Last COS Re-based Year	**2010**

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

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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.



1. Info
A. Data Input Sheet
B. Tax Rates & Exemptions
C. Sch 8 Hist
D. Schedule 10 CEC Hist
E. Sch 13 Tax Reserves Hist
F. Sch 7-1 Loss Cfwd Hist
G. Adj. Taxable Income Historic
H. PILs,Tax Provision Historic
I. Schedule 8 CCA Bridge Year
J. Schedule 10 CEC Bridge Year
K. Sch 13 Tax Reserves Bridge
L. Sch 7-1 Loss Cfwd Bridge
M. Adj. Taxable Income Bridge
N. PILs,Tax Provision Bridge
O. Schedule 8 CCA Test Year
P. Schedule 10 CEC Test Year
Q Sch 13 Tax Reserve Test Year
R. Sch 7-1 Loss Cfwd
S. Taxable Income Test Year
T. PILs,Tax Provision



Rate Base			**$**	**53,797,605**	
Return on Ratebase					
Deemed ShortTerm Debt %	4.00%	T	$	2,151,904	*W = S * T*
Deemed Long Term Debt %	56.00%	U	$	30,126,659	*X = S * U*
Deemed Equity %	40.00%	V	$	21,519,042	*Y = S * V*
Short Term Interest Rate	2.07%	Z	$	44,544	*AC = W * Z*
Long Term Interest	3.70%	AA	$	1,114,686	*AD = X * AA*
Return on Equity (Regulatory Income)	8.98%	AB	**$**	**1,932,410**	*AE = Y * AB*
Return on Rate Base			**$**	**3,091,641**	*AF = AC + AD + AE*

Questions that must be answered	Historic	Bridge	Test Year
1. Does the applicant have any Investment Tax Credits (ITC)?	Yes	Yes	Yes
2. Does the applicant have any SRED Expenditures?	No	No	No
3. Does the applicant have any Capital Gains or Losses for tax purposes?	Yes	No	No
4. Does the applicant have any Capital Leases?	No	No	No
5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	No	No	No
6. Since 1999, has the applicant acquired another regulated applicant's assets?	No	No	No
7. Did the applicant pay dividends? *If Yes, please describe what was the tax treatment in the manager's summary.*	Yes	Yes	Yes
8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes?	No	No	No



Income Tax/PILs Workform for 2014 Filers

Tax Rates Federal & Provincial As of June 20, 2012	Effective January-01-11	Effective January-01-12	Effective January-01-13	Effective January-01-14
Federal income tax				
General corporate rate	38.00%	38.00%	38.00%	38.00%
Federal tax abatement	-10.00%	-10.00%	-10.00%	-10.00%
Adjusted federal rate	28.00%	28.00%	28.00%	28.00%
Rate reduction	-11.50%	-13.00%	-13.00%	-13.00%
	16.50%	15.00%	15.00%	15.00%
Ontario income tax	11.75%	11.50%	11.50%	11.50%
Combined federal and Ontario	28.25%	26.50%	26.50%	26.50%
Federal & Ontario Small Business				
Federal small business threshold	500,000	500,000	500,000	500,000
Ontario Small Business Threshold	500,000	500,000	500,000	500,000
Federal small business rate	11.00%	11.00%	11.00%	11.00%
Ontario small business rate	4.50%	4.50%	4.50%	4.50%



Schedule 8 - Historical Year

Class	Class Description	UCC End of Year Historic per tax returns	Less: Non-Distribution Portion	UCC Regulated Historic Year
1	Distribution System - post 1987	22,109,558		22,109,558
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election			0
2	Distribution System - pre 1988			0
8	General Office/Stores Equip	926,749		926,749
10	Computer Hardware/ Vehicles	667,015		667,015
10.1	Certain Automobiles			0
12	Computer Software			0
13 $_1$	Lease # 1			0
13 $_2$	Lease #2			0
13 $_3$	Lease # 3			0
13 $_4$	Lease # 4			0
14	Franchise			0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs			0
42	Fibre Optic Cable			0
43.1	Certain Energy-Efficient Electrical Generating Equipment			0
43.2	Certain Clean Energy Generation Equipment			0
45	Computers & Systems Software acq'd post Mar 22/04	3,326		3,326
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	97		97
47	Distribution System - post February 2005	21,143,554		21,143,554
50	Data Network Infrastructure Equipment - post Mar 2007	114,725		114,725
52	Computer Hardware and system software			0
95	CWIP			0
1b	Buildings (March 2007)	63,446		63,446
17	Parking Lots, sidewalks	48,704		48,704
				0
				0
				0
				0
				0
				0
				0
				0
	SUB-TOTAL - UCC	45,077,174	0	45,077,174



Schedule 10 CEC - Historical Year

Cumulative Eligible Capital				**238,637**
Additions				
Cost of Eligible Capital Property Acquired during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**238,637**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**238,637**
Current Year Deduction		**238,637**	**x 7% =**	**16,705**
Cumulative Eligible Capital - Closing Balance				**221,932**



Income Tax/PILs Workform for 2014 Filers

Schedule 13 Tax Reserves - Historical

Continuity of Reserves

Description	Historical Balance as per tax returns	Non-Distribution Eliminations	Utility Only
Capital Gains Reserves ss.40(1)			0
Tax Reserves Not Deducted for accounting purposes			
Reserve for doubtful accounts ss. 20(1)(l)			0
Reserve for goods and services not delivered ss. 20(1)(m)			0
Reserve for unpaid amounts ss. 20(1)(n)			0
Debt & Share Issue Expenses ss. 20(1)(e)			0
Other tax reserves			0
			0
			0
			0
			0
			0
Total	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)			
General Reserve for Inventory Obsolescence (non-specific)			0
General reserve for bad debts			0
Accrued Employee Future Benefits:			0
- Medical and Life Insurance			0
-Short & Long-term Disability			0
-Accmulated Sick Leave			0
- Termination Cost			0
- Other Post-Employment Benefits			0
Provision for Environmental Costs			0
Restructuring Costs			0
Accrued Contingent Litigation Costs			0
Accrued Self-Insurance Costs			0
Other Contingent Liabilities			0
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0
Other			0
			0
			0
Total	**0**	**0**	**0**



Income Tax/PILs Workform for 2014 Filers

Schedule 7-1 Loss Carry Forward - Historic

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual Historic			0

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual Historic			0



Income Tax/PILs Workform for 2014 Filers

Adjusted Taxable Income - Historic Year

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Income before PILs/Taxes	A	781,585		781,585
Additions:				
Interest and penalties on taxes	103			0
Amortization of tangible assets	104	3,940,606		3,940,606
Amortization of intangible assets	106			0
Recapture of capital cost allowance from Schedule 8	107			0
Gain on sale of eligible capital property from Schedule 10	108			0
Income or loss for tax purposes- joint ventures or partnerships	109			0
Loss in equity of subsidiaries and affiliates	110			0
Loss on disposal of assets	111			0
Charitable donations	112			0
Taxable Capital Gains	113	53,282		53,282
Political Donations	114			0
Deferred and prepaid expenses	116			0
Scientific research expenditures deducted on financial statements	118			0
Capitalized interest	119			0
Non-deductible club dues and fees	120			0
Non-deductible meals and entertainment expense	121	9,032		9,032
Non-deductible automobile expenses	122			0
Non-deductible life insurance premiums	123			0
Non-deductible company pension plans	124			0
Tax reserves deducted in prior year	125			0
Reserves from financial statements- balance at end of year	126			0
Soft costs on construction and renovation of buildings	127			0
Book loss on joint ventures or partnerships	205			0
Capital items expensed	206			0
Debt issue expense	208			0
Development expenses claimed in current year	212			0
Financing fees deducted in books	216			0
Gain on settlement of debt	220			0
Non-deductible advertising	226			0
Non-deductible interest	227			0
Non-deductible legal and accounting fees	228			0
Recapture of SR&ED expenditures	231			0
Share issue expense	235			0
Write down of capital property	236			0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237			0
Other Additions				
Interest Expensed on Capital Leases	290			0
Realized Income from Deferred Credit Accounts	291			0
Pensions	292			0
Non-deductible penalties	293			0
Ontario Co-operative Education Tax Credit	294	8,167		8,167
Ontario Apprenticeship Training Tax Credit	295	20,000		20,000
ARO Accretion expense				0
Capital Contributions Received (ITA 12(1)(x))				0
Lease Inducements Received (ITA 12(1)(x))				0
Deferred Revenue (ITA 12(1)(a))				0
Prior Year Investment Tax Credits received				0
Regulatory Liabilities 2012 excluding capital		2,106,320		2,106,320
Provision for income taxes - current		507,107		507,107
Provision for income taxes - future		-344,529		-344,529
				0
				0
				0
				0
				0
				0
				0
Total Additions		**6,299,985**	**0**	**6,299,985**

Deductions:				
Gain on disposal of assets per financial statements	401	112,536		112,536
Dividends not taxable under section 83	402			0
Capital cost allowance from Schedule 8	403	3,220,597		3,220,597
Terminal loss from Schedule 8	404			0
Cumulative eligible capital deduction from Schedule 10	405	16,705		16,705
Allowable business investment loss	406			0
Deferred and prepaid expenses	409			0
Scientific research expenses claimed in year	411			0
Tax reserves claimed in current year	413			0
Reserves from financial statements - balance at beginning of year	414			0
Contributions to deferred income plans	416			0
Book income of joint venture or partnership	305			0
Equity in income from subsidiary or affiliates	306			0
Other deductions: (Please explain in detail the nature of the item)				
Interest capitalized for accounting deducted for tax	390			0
Capital Lease Payments	391			0
Non-taxable imputed interest income on deferral and variance accounts	392			0
	393			0
	394			0
ARO Payments - Deductible for Tax when Paid				0
ITA 13(7.4) Election - Capital Contributions Received				0
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds				0
Deferred Revenue - ITA 20(1)(m) reserve				0
Principal portion of lease payments				0
Lease Inducement Book Amortization credit to income				0
Financing fees for tax ITA 20(1)(e) and (e.1)				0
Accumulated Amortization of Regulatory Assets 2011		489,338		489,338
Regulatory Liabilities 2011 excluding capital		1,154,609		1,154,609
Apprenticeship Training and Co-operative Education Investment Tax Credits		38,743		38,743
				0
				0
				0
				0
Total Deductions		**5,032,528**	**0**	**5,032,528**
Net Income for Tax Purposes		**2,049,042**	**0**	**2,049,042**
Charitable donations from Schedule 2	311			0
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320			0
Non-capital losses of preceding taxation years from Schedule 4	331			0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332			0
Limited partnership losses of preceding taxation years from Schedule 4	335			0
TAXABLE INCOME		**2,049,042**	**0**	**2,049,042**



Income Tax/PILs Workform for 2014 Filers

PILs Tax Provision - Historic Year

Note: Input the actual information from the tax returns for the historic year.

							Wires Only	
Regulatory Taxable Income							$ 2,049,042	**A**
Ontario Income Taxes								
Income tax payable	**Ontario Income Tax**		11.50%	**B**	$ 235,640	**C = A * B**		
Small business credit	Ontario Small Business Threshold		$ 500,000	**D**				
	Rate reduction (negative)		-7.00%	**E**	-$ 35,000	**F = D * E**		
Ontario Income tax							$ 200,640	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate				9.79%	**K = J / A**		
	Federal tax rate				15.51%	**L**		
	Combined tax rate						25.30%	**M = K + L**
Total Income Taxes							**$ 518,475**	**N = A * M**
Investment Tax Credits							$ 350	**O**
Miscellaneous Tax Credits							$ 24,659	**P**
Total Tax Credits							**$ 25,009**	**Q = O + P**
Corporate PILs/Income Tax Provision for Historic Year							**$ 493,466**	**R = N - Q**



Income Tax/PILs Workform for 2014 Filers

Schedule 8 CCA - Bridge Year

Class	Class Description	UCC Regulated Historic Year	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Bridge Year CCA	UCC End of Bridge Year
1	Distribution System - post 1987	$ 22,109,558			$ 22,109,558	$ -	$ 22,109,558	4%	$ 884,382	$ 21,225,176
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election				$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988				$ -	$ -	$ -	6%	$ -	$ -
8	General Office/Stores Equip	$ 926,749	$ 40,685		$ 967,434	$ 20,343	$ 947,092	20%	$ 189,418	$ 778,016
10	Computer Hardware/ Vehicles	$ 667,015	$ 247,281		$ 914,296	$ 123,641	$ 790,656	30%	$ 237,197	$ 677,099
10.1	Certain Automobiles				$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software				$ -	$ -	$ -	100%	$ -	$ -
13 1	Lease # 1				$ -	$ -	$ -		$ -	$ -
13 2	Lease #2				$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3				$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4				$ -	$ -	$ -		$ -	$ -
14	Franchise				$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs				$ -	$ -	$ -	8%	$ -	$ -
42	Fibre Optic Cable				$ -	$ -	$ -	12%	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment				$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment				$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 3,326			$ 3,326	$ -	$ 3,326	45%	$ 1,497	$ 1,829
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ 97			$ 97	$ -	$ 97	30%	$ 29	$ 68
47	Distribution System - post February 2005	$ 21,143,554	$ 4,930,084	-$ 1,666,572	$ 24,407,066	$ 1,631,756	$ 22,775,310	8%	$ 1,822,025	$ 22,585,041
50	Data Network Infrastructure Equipment - post Mar 2007	$ 114,725	$ 253,125		$ 367,850	$ 126,563	$ 241,288	55%	$ 132,708	$ 235,142
52	Computer Hardware and system software				$ -	$ -	$ -	100%	$ -	$ -
95	CWIP				$ -	$ -	$ -		$ -	$ -
1b	Buildings (March 2007)	$ 63,446			$ 63,446	$ -	$ 63,446	6%	$ 3,807	$ 59,639
17	Parking Lots, sidewalks	$ 48,704			$ 48,704	$ -	$ 48,704	8%	$ 3,896	$ 44,808
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
	TOTAL	$ 45,077,174	$ 5,471,175	-$ 1,666,572	$ 48,881,777	$ 1,902,302	$ 46,979,476		$ 3,274,959	$ 45,606,818



Schedule 10 CEC - Bridge Year

Cumulative Eligible Capital				**221,932**
Additions				
Cost of Eligible Capital Property Acquired during Test Year	29,835			
Other Adjustments	0			
Subtotal	29,835	**x 3/4 =**	22,376	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			22,376	**22,376**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**244,309**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**244,309**
Current Year Deduction		**244,309**	**x 7% =**	**17,102**
Cumulative Eligible Capital - Closing Balance				**227,207**



Income Tax/PILs Workform for 2014 Filers

Schedule 13 Tax Reserves - Bridge Year

Continuity of Reserves

Description	Historic Utility Only	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance	Bridge Year Adjustments		Balance for Bridge Year	Change During the Year	Disallowed Expenses
				Additions	Disposals			
Capital Gains Reserves ss.40(1)	0		0			0	0	
Tax Reserves Not Deducted for accounting purposes								
Reserve for doubtful accounts ss. 20(1)(l)	0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)	0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0		0			0	0	
Other tax reserves	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)								
General Reserve for Inventory Obsolescence (non-specific)	0		0			0	0	
General reserve for bad debts	0		0			0	0	
Accrued Employee Future Benefits:	0		0			0	0	
- Medical and Life Insurance	0		0			0	0	
-Short & Long-term Disability	0		0			0	0	
-Accmulated Sick Leave	0		0			0	0	
- Termination Cost	0		0			0	0	
- Other Post-Employment Benefits	0		0			0	0	
Provision for Environmental Costs	0		0			0	0	
Restructuring Costs	0		0			0	0	
Accrued Contingent Litigation Costs	0		0			0	0	
Accrued Self-Insurance Costs	0		0			0	0	
Other Contingent Liabilities	0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	0		0			0	0	
Other	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**



Income Tax/PILs Workform for 2014 Filers

Corporation Loss Continuity and Application

Schedule 7-1 Loss Carry Forward - Bridge Year

Non-Capital Loss Carry Forward Deduction	Total
Actual Historic	0
Application of Loss Carry Forward to reduce taxable income in Bridge Year	
Other Adjustments Add (+) Deduct (-)	
Balance available for use in Test Year	0
Amount to be used in Bridge Year	
Balance available for use post Bridge Year	0

Net Capital Loss Carry Forward Deduction	Total
Actual Historic	0
Application of Loss Carry Forward to reduce taxable income in Bridge Year	
Other Adjustments Add (+) Deduct (-)	
Balance available for use in Test Year	0
Amount to be used in Bridge Year	
Balance available for use post Bridge Year	0



Income Tax/PILs Workform for 2014 Filers

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Total for Regulated Utility
Income before PILs/Taxes	A	2,593,699
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets	104	2,157,353
Amortization of intangible assets	106	
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	9,032
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves deducted in prior year	125	0
Reserves from financial statements- balance at end of year	126	0
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
	294	
Apprenticeship Tax Credit	295	19,000
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		350
Total Additions		**2,185,735**



Income Tax/PILs Workform for 2014 Filers

Adjusted Taxable Income - Bridge Year

Deductions:		
Gain on disposal of assets per financial statements	401	5,603
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	3,274,959
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10	405	17,102
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves claimed in current year	413	0
Reserves from financial statements - balance at beginning of year	414	0
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	
Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to income		
Financing fees for tax ITA 20(1)(e) and (e.1)		
Total Deductions		**3,297,664**
Net Income for Tax Purposes		**1,481,770**
Charitable donations from Schedule 2	311	
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320	
Non-capital losses of preceding taxation years from Schedule 4	331	
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
TAXABLE INCOME		**1,481,770**



Income Tax/PILs Workform for 2014 Filers

PILS Tax Provision - Bridge Year

							Wires Only	
Regulatory Taxable Income							$ 1,481,770	**A**
Ontario Income Taxes								
Income tax payable	**Ontario Income Tax**	11.50%	**B**	$	170,404	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ 500,000	**D**					
	Rate reduction	-7.00%	**E**	-$	35,000	**F = D * E**		
Ontario Income tax							$ 135,404	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			9.14%		**K = J / A**		
	Federal tax rate			15.00%		**L**		
	Combined tax rate						24.14%	**M = K + L**
Total Income Taxes							**$ 357,669**	**N = A * M**
Investment Tax Credits							$ 2,000	**O**
Miscellaneous Tax Credits							$ 19,000	**P**
Total Tax Credits							**$ 21,000**	**Q = O + P**
Corporate PILs/Income Tax Provision for Bridge Year							**$ 336,669**	**R = N - Q**

Note:

1. This is for the derivation of Bridge year PILs income tax expense and should not be used for Test year revenue requirement calculations.



Income Tax/PILs Workform for 2014 Filers

Schedule 8 CCA - Test Year

Class	Class Description	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	$ 21,225,176			$ 21,225,176	$ -	$ 21,225,176	4%	$ 849,007	$ 20,376,169
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -			$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ -			$ -	$ -	$ -	6%	$ -	$ -
8	General Office/Stores Equip	$ 778,016	72,250		$ 850,266	$ 36,125	$ 814,141	20%	$ 162,828	$ 687,438
10	Computer Hardware/ Vehicles	$ 677,099	218,400		$ 895,499	$ 109,200	$ 786,299	30%	$ 235,890	$ 659,610
10.1	Certain Automobiles	$ -			$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ -			$ -	$ -	$ -	100%	$ -	$ -
13 1	Lease # 1	$ -			$ -	$ -	$ -		$ -	$ -
13 2	Lease #2	$ -			$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3	$ -			$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4	$ -			$ -	$ -	$ -		$ -	$ -
14	Franchise	$ -			$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bl	$ -			$ -	$ -	$ -	8%	$ -	$ -
42	Fibre Optic Cable	$ -			$ -	$ -	$ -	12%	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -			$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment	$ -			$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 1,829			$ 1,829	$ -	$ 1,829	45%	$ 823	$ 1,006
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ 68			$ 68	$ -	$ 68	30%	$ 20	$ 48
47	Distribution System - post February 2005	$ 22,585,041	4,856,604		$ 27,441,645	$ 2,428,302	$ 25,013,343	8%	$ 2,001,067	$ 25,440,578
50	Data Network Infrastructure Equipment - post Mar 2007	$ 235,142	389,989		$ 625,131	$ 194,995	$ 430,136	55%	$ 236,575	$ 388,556
52	Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ -			$ -	$ -	$ -	0%	$ -	$ -
1b	Buildings (March 2007)	$ 59,639			$ 59,639	$ -	$ 59,639	6%	$ 3,578	$ 56,061
17	Parking Lots, sidewalks	$ 44,808			$ 44,808	$ -	$ 44,808	8%	$ 3,585	$ 41,223
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	$ 45,606,818	$ 5,537,243	$ -	$ 51,144,061	$ 2,768,622	$ 48,375,439		$ 3,493,374	$ 47,650,687



Income Tax/PILs Workform for 2014 Filers

Schedule 10 CEC - Test Year

Cumulative Eligible Capital					**227,207**
Additions					
Cost of Eligible Capital Property Acquired during Test Year		441,675			
Other Adjustments		0			
	Subtotal	441,675	**x 3/4 =**	331,256	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002		0	**x 1/2 =**	0	
				331,256	**331,256**
Amount transferred on amalgamation or wind-up of subsidiary		0			**0**
	Subtotal				**558,463**
Deductions					
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year		0			
Other Adjustments		0			
	Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance					**558,463**
Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")			**558,463**	**x 7% =**	**39,092**
Cumulative Eligible Capital - Closing Balance					**519,371**



Schedule 13 Tax Reserves - Test Year

Continuity of Reserves

Description	Bridge Year	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance	Test Year Adjustments: Additions	Test Year Adjustments: Disposals	Balance for Test Year	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	0		0			0	0	
Tax Reserves Not Deducted for accounting purposes								
Reserve for doubtful accounts ss. 20(1)(l)	0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)	0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0		0			0	0	
Other tax reserves	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)								
General Reserve for Inventory Obsolescence (non-specific)	0		0			0	0	
General reserve for bad debts	0		0			0	0	
Accrued Employee Future Benefits:	0		0			0	0	
- Medical and Life Insurance	0		0			0	0	
-Short & Long-term Disability	0		0			0	0	
-Accmulated Sick Leave	0		0			0	0	
- Termination Cost	0		0			0	0	
- Other Post-Employment Benefits	0		0			0	0	
Provision for Environmental Costs	0		0			0	0	
Restructuring Costs	0		0			0	0	
Accrued Contingent Litigation Costs	0		0			0	0	
Accrued Self-Insurance Costs	0		0			0	0	
Other Contingent Liabilities	0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	0		0			0	0	
Other	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**



Income Tax/PILs Workform for 2014 Filers

Schedule 7-1 Loss Carry Forward - Test Year

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year			0
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year			0
Balance available for use post Test Year	0	0	0

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year			0
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year			0
Balance available for use post Test Year	0	0	0



Taxable Income - Test Year

		Test Year Taxable Income
Net Income Before Taxes		1,932,410

	T2 S1 line #	
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	2,117,957
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106	
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	9,032
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves beginning of year	125	0
Reserves from financial statements- balance at end of year	126	0
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions: (please explain in detail the nature of the item)		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
	294	
Apprenticeship Tax Credits	295	26,000
	296	
	297	
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		2,000
Total Additions		**2,154,989**

Deductions:		
Gain on disposal of assets per financial statements	401	13,940
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	3,493,374
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10 CEC	405	39,092
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves end of year	413	0
Reserves from financial statements - balance at beginning of year	414	0
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	
Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
	395	
	396	
	397	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to income		
Financing fees for tax ITA 20(1)(e) and (e.1)		
Total Deductions		**3,546,406**
NET INCOME FOR TAX PURPOSES		**540,993**
Charitable donations	311	
Taxable dividends received under section 112 or 113	320	
Non-capital losses of preceding taxation years from Schedule 7-1	331	
Net-capital losses of preceding taxation years (Please show calculation)	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
REGULATORY TAXABLE INCOME		**540,993**



Income Tax/PILs Workform for 2014 Filers

PILs Tax Provision - Test Year

							Wires Only	
Regulatory Taxable Income							$ 540,993	**A**
Ontario Income Taxes								
Income tax payable	**Ontario Income Tax**	11.50%	**B**	$	62,214	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ 500,000	**D**					
	Rate reduction	-7.00%	**E**	-$	35,000	**F = D * E**		
Ontario Income tax							$ 27,214	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate				5.03%	**K = J / A**		
	Federal tax rate				15.00%	**L**		
	Combined tax rate						20.03%	**M = K + L**
Total Income Taxes							**$ 108,363**	**N = A * M**
Investment Tax Credits							$ 2,000	**O**
Miscellaneous Tax Credits							$ 26,000	**P**
Total Tax Credits							**$ 28,000**	**Q = O + P**
Corporate PILs/Income Tax Provision for Test Year							**$ 80,363**	**R = N - Q**
Corporate PILs/Income Tax Provision Gross Up [1]					79.97%	**S = 1 - M**	**$ 20,129**	**T = R / S - R**
Income Tax (grossed-up)							**$ 100,492**	**U = R + T**

Note:

1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

200

055 Do not use this area

CLIENT'S COPY

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial [illegible]ration return.

All legislative references on this return are to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business number (BN) 001 89075 9814 RC0001

Corporation's name
002 HALDIMAND COUNTY HYDRO INC.

Address of head office
Has this address changed since the last time we were notified? . . . . . 010 1 Yes ☐ 2 No ☒
(If yes, complete lines 011 to 018.)
011 1 GREENDALE DRIVE R. R. #2
012

City	Province, territory, or state
015 CALEDONIA	016 ON
Country (other than Canada)	**Postal code/Zip code**
017	018 N3W 2J3

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? . . . . . 020 1 Yes ☐ 2 No ☒
(If yes, complete lines 021 to 028.)
021 c/o
022

City	Province, territory, or state
025	026
Country (other than Canada)	**Postal code/Zip code**
027	028

Location of books and records
Has the location of books and records changed since the last time we were notified? . . . . . 030 1 Yes ☐ 2 No ☒
(If yes, complete lines 031 to 038.)
031 1 GREENDALE DRIVE R. R. #2
032

City	Province,territory, or state
035 CALEDONIA	036 ON
Country (other than Canada)	**Postal code/Zip code**
037	038 N3W 2J3

040 Type of corporation at the end of the tax year

1 ☒ Canadian-controlled private corporation (CCPC)
2 ☐ Other private corporation
3 ☐ Public corporation
4 ☐ Corporation controlled by a public corporation
5 ☐ Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. 043 _____ YYYY MM DD

To which tax year does this return apply?

Tax year start	Tax year-end
060 2012-01-01	061 2012-12-31
YYYY MM DD	YYYY MM DD

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . . 063 1 Yes ☐ 2 No ☒

If yes, provide the date control was acquired . . . . . 065 _____ YYYY MM DD

Is the date on line 061 a deemed tax year-end according to:

subparagraph 88(2)(a)(iv)? . . . . . 064 1 Yes ☐ 2 No ☒
subsection 249(3.1)? . . . . . 066 1 Yes ☐ 2 No ☒

Is the corporation a professional corporation that is a member of a partnership? . . . . . 067 1 Yes ☐ 2 No ☒

Is this the first year of filing after:

Incorporation? . . . . . 070 1 Yes ☐ 2 No ☒
Amalgamation? . . . . . 071 1 Yes ☐ 2 No ☒
If yes, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . . 072 1 Yes ☐ 2 No ☒
If yes, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . . 076 1 Yes ☐ 2 No ☒

Is this the final return up to dissolution? . . . . . 078 1 Yes ☐ 2 No ☒

If an election was made under section 261, state the functional currency used . . . . . 079 _____

Is the corporation a resident of Canada?
080 1 Yes ☒ 2 No ☐ If no, give the country of residence on line 081 and complete and attach Schedule 97.
081 _____

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . . 082 1 Yes ☐ 2 No ☒
If yes, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085
1 ☐ Exempt under paragraph 149(1)(e) or (l)
2 ☐ Exempt under paragraph 149(1)(j)
3 ☐ Exempt under paragraph 149(1)(t)
4 ☐ Exempt under other paragraphs of section 149

Do not use this area

095 _____ 096 _____

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, attach the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
e corporation related to any other corporations?	150	X	9
ne corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders who own voting shares?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered yes to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
he corporation realized any capital gains or incurred any capital losses during the tax year?	206	X	6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	207	X	7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231	X	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
corporation claiming a Canadian film or video production tax credit refund?	253		T1131
e corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270	1 Yes	2 No X
Is the corporation inactive?	280	1 Yes	2 No X

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution US

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	UTILITY	285 100.000 %
286		287 %
288		289 %

Did the corporation immigrate to Canada during the tax year?	291	1 Yes	2 No X
Did the corporation emigrate from Canada during the tax year?	292	1 Yes	2 No X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293	1 Yes	2 No

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 ____ (YYYY MM DD)

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 1 Yes 2 No

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.	300	2,049,042	A
Deduct: Charitable donations from Schedule 2	311		
Gifts to Canada, a province, or a territory from Schedule 2	312		
Cultural gifts from Schedule 2	313		
Ecological gifts from Schedule 2	314		
Gifts of medicine from Schedule 2	315		
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320		
Part VI.1 tax deduction*	325		
Non-capital losses of previous tax years from Schedule 4	331		
Net capital losses of previous tax years from Schedule 4	332		
Restricted farm losses of previous tax years from Schedule 4	333		
Farm losses of previous tax years from Schedule 4	334		
Limited partnership losses of previous tax years from Schedule 4	335		
Taxable capital gains or taxable dividends allocated from a central credit union	340		
Prospector's and grubstaker's shares	350		
Subtotal			B
Subtotal (amount A **minus** amount B) (if negative, enter "0")		2,049,042	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355		D
Taxable income (amount C **plus** amount D)	360	2,049,042	
Income exempt under paragraph 149(1)(t)	370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)		2,049,042	Z

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 8. Use 3.2 for tax years ending before 2012.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 ..... **400** 1,995,760 A

Taxable income from line 360 on page 3, **minus** 100/28* 3.57143 of the amount on line 632** on page 7, **minus** (38 - X***) 4 times the amount on line 636*** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax ..... **405** 2,049,042 B

Business limit (see notes 1 and 2 below) ..... **410** 500,000 C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 500,000 x **415** ***** 99,450 / 11,250 D = ... 4,420,000 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") ..... **425** F

Small business deduction

Amount A, B, C, or F, whichever is the least _____ x 17 % = ... **430** G

Enter amount G on line 1 on page 7.

* 10/3 for tax years ending before November 1, 2011. The result of the multiplication by line 632 has to be pro-rated based on the number of days in the tax year that are in each period: before November 1, 2011, and after October 31, 2011.

** Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

*** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

**** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

***** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3*			2,049,042 A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27			B
Amount QQ from Part 13 of Schedule 27			C
Personal service business income**	432		D
Amount used to calculate the credit union deduction from Schedule 17			E
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least			F
Aggregate investment income from line 440 on page 6***		53,282	G
Total of amounts B to G		53,282 ▶	53,282 H
Amount A **minus** amount H (if negative, enter "0")			1,995,760 I

Amount I	1,995,760	x	Number of days in the tax year before January 1, 2011 / Number of days in the tax year	366	x 10 %	=	J
Amount I	1,995,760	x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	366	x 11.5 %	=	K
Amount I	1,995,760	x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	366 / 366	x 13 %	=	259,449 L

General tax reduction for Canadian-controlled private corporations – Total of amounts J to L . . . . . 259,449 M
Enter amount M on line 638 on page 7.

* For tax years ending after October 31, 2011, line 360 or amount Z, whichever applies.
** For tax years beginning after October 31, 2011.
*** Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)			N
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27			O
Amount QQ from Part 13 of Schedule 27			P
Personal service business income*	434		Q
Amount used to calculate the credit union deduction from Schedule 17			R
Total of amounts O to R		▶	S
Amount N **minus** amount S (if negative, enter "0")			T

Amount T		x	Number of days in the tax year before January 1, 2011 / Number of days in the tax year	366	x 10 %	=	U
Amount T		x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	366	x 11.5 %	=	V
Amount T		x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	366 / 366	x 13 %	=	W

General tax reduction – Total of amounts U to W X
Enter amount X on line 639 on page 7.

* For tax years beginning after October 31, 2011.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income (Schedule 7) ..... 440 53,282 x 26 2/3 % = 14,209 A

Foreign non-business income tax credit from line 632 on page 7 .....

Deduct:

Foreign investment income from Schedule 7 ..... 445 x 91 1/3 % = (if negative, enter "0") ▶ B

Amount A **minus** amount B (if negative, enter "0") ..... 14,209 C

Taxable income from line 360 on page 3 2,049,042

Deduct:

Amount from line 400, 405, 410, or 425 on page 4, whichever is the least .....

Foreign non-business income tax credit from line 632 on page 7 ... x 25/9* = 100 / 35

Foreign business income tax credit from line 636 on page 7 ..... x 1(0.38 - X**) = 4

▶

2,049,042

x 26 2/3 % = 546,411 D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) ..... 317,485 E

Refundable portion of Part I tax – Amount C, D, or E, whichever is the least ..... 450 14,209 F

* 100/35 for tax years beginning after October 31, 2011.

** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year 460

Deduct: Dividend refund for the previous tax year ..... 465 ▶ G

Add the total of:

Refundable portion of Part I tax from line 450 above 14,209

Total Part IV tax payable from Schedule 3 .....

Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation 480

14,209 ▶ 14,209 H

Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H 485 14,209

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3 ..... 611,329 x 1/3 = 203,776 I

Refundable dividend tax on hand at the end of the tax year from line 485 above ..... 14,209 J

Dividend refund – Amount I or J, whichever is less (enter this amount on line 784 on page 8) 14,209

Part I tax

Base amount of Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied by** 38 %		550	778,636	A
Recapture of investment tax credit from Schedule 31		602		B

;ulation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(i it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6			53,282	i
Taxable income from line 360 on page 3	2,049,042			
Deduct:				
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least				
Net amount	2,049,042 ▶		2,049,042	ii
Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii		604	3,552	C
		Subtotal (add lines A to C)	782,188	D

Deduct:				
Small business deduction from line 430 on page 4				1
Federal tax abatement		608	204,904	
Manufacturing and processing profits deduction from Schedule 27		616		
Investment corporation deduction		620		
Taxed capital gains 624				
Additional deduction – credit unions from Schedule 17		628		
Federal foreign non-business income tax credit from Schedule 21		632		
Federal foreign business income tax credit from Schedule 21		636		
General tax reduction for CCPCs from amount M on page 5		638	259,449	
General tax reduction from amount X on page 5		639		
Federal logging tax credit from Schedule 21		640		
Federal qualifying environmental trust tax credit		648		
;stment tax credit from Schedule 31		652	350	
		Subtotal	464,703 ▶	464,703 E

Part I tax payable – Line D **minus** line E		317,485 F
Enter amount F on line 700 on page 8.		

Summary of tax and credits

Federal tax

Part I tax payable from page 7	700	317,485
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		317,485

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	190,190	
Provincial tax on large corporations (Nova Scotia Schedule 342)	765		
(The Nova Scotia tax on large corporations is eliminated effective July 2012.)		190,190 ▶	190,190
Total tax payable	770		507,675 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund from page 6	784	14,209	
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld	801		
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	1,081,552	
Total credits	890	1,095,761 ▶	1,095,761 B

Refund code 894 1 Overpayment 588,086

Balance (line A **minus** line B) -588,086

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid

Enclosed payment 898

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 Branch number

914 Institution number 918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No ☒

Certification

I, 950 ALBERT (Last name (print)) 951 R. JANE (First name (print)) 954 PRESIDENT & CEO (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2013-05-03 (Date (yyyy/mm/dd)) Signature of the authorized signing officer of the corporation

956 (905) 765-5211 Telephone number

Is the contact person the same as the authorized signing officer? If no, complete the information below 957 1 Yes ☒ 2 No ☐

958 Name (print) 959 Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering 1 for English or 2 for French.
Indiquez votre langue de correspondance en inscrivant 1 pour anglais ou 2 pour français.

990 1

Schedule of Instalment Remittances

Name of corporation contact

Phone number

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
	Total installments for the year	1,081,552

Total amount of instalments claimed (carry the result to line 840 of the T2 Return) 1,081,552 A

Total instalments credited to the taxation year per T9 1,081,552 B

Transfer

Account number	Taxation year end	Amount	Effective interest date	Description
From:				
From:				
To:				
From:				
To:				
From:				
To:				
From:				
To:				

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SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2012-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
Assets					
	Total current assets	1599	+	17,982,265	14,806,902
	Total tangible capital assets	2008	+	75,348,855	66,179,542
	Total accumulated amortization of tangible capital assets	2009	–	30,318,132	26,385,862
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	1,615,829	3,556,129
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	64,628,817	58,156,711
Liabilities					
	Total current liabilities	3139	+	11,218,275	9,364,021
	Total long-term liabilities	3450	+	15,804,630	11,386,158
	* Subordinated debt	3460	+	3,136,228	3,107,104
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	30,159,133	23,857,283
Shareholder equity					
	Total shareholder equity (mandatory field)	3620	+	34,469,684	34,299,428
	Total liabilities and shareholder equity	3640	=	64,628,817	58,156,711
Retained earnings					
	Retained earnings/deficit – end (mandatory field)	3849	=	14,588,979	14,418,723

* Generic item

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SCHEDULE 100

Current Assets

Form identifier 1599

Account	Description	GIFI		Current year	Prior year
Cash and deposits					
	* Cash and deposits	1000		5,683,888	3,941,761
	Cash and deposits		+	5,683,888	3,941,761
Accounts receivable					
	* Accounts receivable	1060		10,099,158	8,754,224
	Accounts receivable		+	10,099,158	8,754,224
Inventories					
	* Inventories	1120		1,334,139	1,254,484
	Inventories		+	1,334,139	1,254,484
Other current assets					
	Taxes recoverable/refundable	1483		588,086	585,578
	Prepaid expenses	1484		276,994	270,855
	Other current assets		+	865,080	856,433
	Total current assets	1599	=	17,982,265	14,806,902

* Generic item

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SCHEDULE 100

Tangible Capital Assets and Accumulated Amortization

Form identifier 2008/2009

Account	Description	GIFI		Tangible capital assets		Accumulated amortization	Prior year
Land							
	* Land	1600	+	127,140			131,280
	Total			127,140			
Buildings							
	* Buildings	1680	+	2,190,518			2,168,016
	*Accumulated amortization of buildings	1681	–			467,768	416,249
	Total			2,190,518		467,768	
Other tangible capital assets							
	* Other tangible capital assets	1900	+	73,031,197			63,880,246
	*Accumulated amortization of other tangible capital assets	1901	–			29,850,364	25,969,613
	Total			73,031,197		29,850,364	
	Total tangible capital assets	2008	=	75,348,855			66,179,542
	Total accumulated amortization of tangible capital assets	2009			=	30,318,132	26,385,862

* Generic item

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SCHEDULE 100

Long-term Assets

Form identifier 2589

Account	Description	GIFI	Current year	Prior year
	Other long-term assets			
	* Other long-term assets	2420		2,284,829
	Future (deferred) income taxes	2421	1,615,829	1,271,300
	Other long-term assets	+	1,615,829	3,556,129
	Total long-term assets	2589 =	1,615,829	3,556,129

* Generic item

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SCHEDULE 100

Current Liabilities

Form identifier 3139

Account	Description	GIFI		Current year	Prior year
Amounts payable and accrued liabilities					
	* Amounts payable and accrued liabilities	2620		9,148,218	7,696,114
	Amounts payable and accrued liabilities		+	9,148,218	7,696,114
Due to related parties					
	* Due to related parties	2860		715,109	640,964
	Due to related parties		+	715,109	640,964
	* Current portion of long-term liability	2920	+	1,354,948	1,023,662
Other current liabilities					
	* Other current liabilities	2960			3,281
	Other current liabilities		+		3,281
	Total current liabilities	3139	=	11,218,275	9,364,021

* Generic item

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Long-term Liabilities

Form identifier 3450

Account	Description	GIFI		Current year	Prior year
	* Bonds and debentures	3210	+	14,549,047	11,936,339
	Other long-term liabilities				
	* Other long-term liabilities	3320		-1,354,948	-1,023,662
	Long-term obligations/commitments/capital leases	3321		2,106,320	
	General provisions/reserves	3325		504,211	473,481
	Other long-term liabilities		+	1,255,583	-550,181
	Total long-term liabilities	3450	=	15,804,630	11,386,158

* Generic item

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SCHEDULE 100

Shareholder Equity

Form identifier 3620

Account	Description	GIFI		Current year	Prior year
	* Common shares	3500	+	17,144,796	17,144,796
	Contributed and other surplus				
	Contributed surplus	3541		2,735,909	2,735,909
	Contributed and other surplus		+	2,735,909	2,735,909
	* Retained earnings/deficit	3600	+	14,588,979	14,418,723
	Total shareholder equity	3620	=	34,469,684	34,299,428

* Generic item

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SCHEDULE 100

Retained Earnings/Deficit

Form identifier 3849

Account	Description	GIFI		Current year	Prior year
	* Retained earnings/deficit – start	3660	+	14,418,723	12,756,791
	* Net income/loss	3680	+	781,585	2,378,682
	Dividends declared				
	* Dividends declared	3700		611,329	716,750
	Dividends declared		–	611,329	716,750
	Retained earnings/deficit – end	3849	=	14,588,979	14,418,723

* Generic item

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SCHEDULE 125

Form Identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2012-12-31

Income statement information

Description	GIFI
Operating name	0001
Description of the operation	0002
Sequence number	0003 01

Account	Description	GIFI		Current year	Prior year
Income statement information					
	Total sales of goods and services	8089	+	54,238,770	53,256,430
	Cost of sales	8518	–		
	Gross profit/loss	8519	=	54,238,770	53,256,430
	Cost of sales	8518	+		
	Total operating expenses	9367	+	53,294,607	49,918,932
	Total expenses (mandatory field)	9368	=	53,294,607	49,918,932
	Total revenue (mandatory field)	8299	+	54,238,770	53,256,430
	Total expenses (mandatory field)	9368	–	53,294,607	49,918,932
	Net non-farming income	9369	=	944,163	3,337,498
Farming income statement information					
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	944,163	3,337,498
	Total other comprehensive income	9998	=		
Extraordinary items and income (linked to Schedule 140)					
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	507,107	1,047,943
	Future (deferred) income tax provision	9995	–	-344,529	-89,127
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	781,585	2,378,682

UNAUDITED
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Revenue

Form identifier 8299

Account	Description	GIFI		Current year	Prior year
	* Trade sales of goods and services	8000	+	54,238,770	53,256,430
	Total sales of goods and services	8089	=	54,238,770	53,256,430
	Total revenue	8299	=	54,238,770	53,256,430

* Generic item

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Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 141

NOTES CHECKLIST

e of corporation	Business Number	Tax year-end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2012-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the "accountant") who prepared or reported on the financial statements.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and Guide T4012, *T2 Corporation – Income Tax Guide.*
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . . . 095 1 Yes [X] 2 No [ ]

Is the accountant connected* with the corporation? . . . . . 097 1 Yes [ ] 2 No [X]

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note: If the accountant does not have a professional designation or is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4, as applicable.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: 198

Completed an auditor's report	1	[ ]
Completed a review engagement report	2	[ ]
Conducted a compilation engagement	3	[X]

Part 3 – Reservations

If you selected option "1" or "2" under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . . . 099 1 Yes [ ] 2 No [ ]

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: 110

Prepared the tax return (financial statements prepared by client)	1	[ ]
Prepared the tax return and the financial information contained therein (financial statements have not been prepared)	2	[ ]

Were notes to the financial statements prepared? . . . . . 101 1 Yes [ ] 2 No [X]

If yes, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes? . . . . . 104 1 Yes [ ] 2 No [ ]

Is re-evaluation of asset information mentioned in the notes? . . . . . 105 1 Yes [ ] 2 No [ ]

Is contingent liability information mentioned in the notes? . . . . . 106 1 Yes [ ] 2 No [ ]

Is information regarding commitments mentioned in the notes? . . . . . 107 1 Yes [ ] 2 No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . 108 1 Yes [ ] 2 No [X]

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Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? 200 1 Yes ☐ 2 No ☒

If yes, enter the amount recognized:

		In net income Increase (decrease)		In OCI Increase (decrease)
Property, plant, and equipment	210		211	
Intangible assets	215		216	
Investment property	220			
Biological assets	225			
Financial instruments	230		231	
Other	235		236	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year? 250 1 Yes ☐ 2 No ☒

Did the corporation apply hedge accounting during the tax year? 255 1 Yes ☐ 2 No ☒

Did the corporation discontinue hedge accounting during the tax year? 260 1 Yes ☐ 2 No ☒

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? 265 1 Yes ☐ 2 No ☒

If yes, you have to maintain a separate reconciliation.

NOTICE TO READER

ON THE BASIS OF INFORMATION PROVIDED BY MANAGEMENT, WE HAVE COMPILED THE G.I.F.I.

WE HAVE NOT PERFORMED AN AUDIT OR A REVIEW ENGAGEMENT IN RESPECT OF THIS FINANCIAL INFORMATION AND, ACCORDINGLY, WE EXPRESS NO ASSURANCE THEREON.

READERS ARE CAUTIONED THAT THIS FINANCIAL INFORMATION MAY NOT BE APPROPRIATE FOR THEIR PURPOSES.

MILLARD, ROUBE & ROSEBRUGH LLP
LICENSED PUBLIC ACCOUNTANTS
GRAVENHURST, ONTARIO

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Net Income (Loss) for Income Tax Purposes

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
ALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2012-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125				781,585 A
Add:				
Provision for income taxes – current		101	507,107	
Provision for income taxes – deferred		102	-344,529	
Amortization of tangible assets		104	3,940,606	
Taxable capital gains from Schedule 6		113	53,282	
Non-deductible meals and entertainment expenses		121	9,032	
	Subtotal of additions		4,165,498 ▶	4,165,498
Other additions:				
Resource amounts deducted		232		
Miscellaneous other additions:				
603				
Inducement - ITA 12(1)x)	28,167			
	Total 28,167	293	28,167	
604 Reg liabilities 2012 excl. capital	2,106,320			
	Total 2,106,320	294	2,106,320	
	Subtotal of other additions	199	2,134,487 ▶	2,134,487
	Total additions	500	6,299,985 ▶	6,299,985 B
Amount A **plus** amount B				7,081,570
Deduct:				
Gain on disposal of assets per financial statements		401	112,536	
Capital cost allowance from Schedule 8		403	3,220,597	
Cumulative eligible capital deduction from Schedule 10		405	16,705	
	Subtotal of deductions		3,349,838 ▶	3,349,838
Other deductions:				
Miscellaneous other deductions:				
700 ATTC and COOP ITCs		390	38,743	
704 ACC AMORT OF REG ASSETS 2011	489,338			
REG LIA 2011 excl capital	1,154,609			
	Total 1,643,947	394	1,643,947	
	Subtotal of other deductions	499	1,682,690 ▶	1,682,690
	Total deductions	510	5,032,528 ▶	5,032,528
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				2,049,042

SCH 1 E (12)

Canada

Inducement

This form is used to calculate inducements that a corporation must add to its income under paragraph 12(1)x) of the ITA. If an amount reduces the capital cost of property, this amount will be indicated in Part "Tax credits whose amount should reduce the capital cost of property."

If you want to transfer an amount to Schedule 1 and include it in the corporation's income for tax purposes, select the corresponding check box in column A. You can also select the option **Select this check box to add all the amounts to income calculated in Schedule 1** to transfer all the amounts to Schedule 1. In either case, the column A check box will be selected for that amount and it will therefore be updated to Schedule 1.

Tax credits whose amount should be added to income

Select this check box to add all the amounts to income calculated in Schedule 1. ☐

Ontario

A		
☒	Portion of the Ontario research and development tax credit that relates to the prescribed proxy amount (PPA)	
☒	Ontario co-operative education tax credit	8,167
☒	Ontario apprenticeship training tax credit	20,000
☐	Ontario computer animation and special effects tax credit*	
	* Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario film and television tax credit*	
	* Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario production services tax credit*	
	* Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario interactive digital media tax credit*	
	* Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario sound recording tax credit*	
	* Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario book publishing tax credit	
☒	Portion of the Ontario innovation tax credit that relates to the prescribed proxy amount (PPA)	
☐	Ontario business-research institute tax credit	

Tax credits whose amount should reduce the capital cost of property

Canada Revenue Agency / Agence du revenu du Canada

DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation	Business Number	Tax year-end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2012-12-31

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid in the tax year that qualify for a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act*.
- A recipient corporation is connected with a payer corporation at any time in a tax year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- "X" under column A if dividend received from a foreign source (connected corporation only).
- Enter in column F1, the amount of dividends received reported in column 240 that are eligible.
- Under column F2, enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received in the tax year

Do not include dividends received from foreign non-affiliates.

Name of payer corporation (from which the corporation received the dividend) 200	A	Complete if payer corporation is connected: B Enter 1 if payer corporation is connected 205	C Business Number of connected corporation 210	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYY/MM/DD (See note) 220	E Non-taxable dividend under section 83 230

Total (enter on line 402 of Schedule 1)

Note: If your corporation's tax year-end is different than that of the connected payer corporation, your corporation could have received dividends from more than one tax year of the payer corporation. If so, use a separate line to provide the information for each tax year of the payer corporation. For more details, consult the Help.

F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d)* 240	F1 Eligible dividends (included in column F)	F2	Complete if payer corporation is connected: G Total taxable dividends paid by connected payer corporation (for tax year in column D) 250	H Dividend refund of the connected payer corporation (for tax year in column D)** 260	I Part IV tax before deductions F x 1 / 3 *** 270	
						J

Total (enter the amount from column F on line 320 of the T2 return and amount J in Part 2)

* If taxable dividends are received, enter the amount in column 240, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column 270. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

** If the connected payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

*** For dividends received from connected corporations: Part IV tax = $\frac{\text{Column F x Column H}}{\text{Column G}}$

Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1) . . . . . .

Deduct:

Part IV.1 tax payable on dividends subject to Part IV tax 320

Subtotal

Deduct:

Current-year non-capital loss claimed to reduce Part IV tax	330	
Non-capital losses from previous years claimed to reduce Part IV tax	335	
Current-year farm loss claimed to reduce Part IV tax	340	
Farm losses from previous years claimed to reduce Part IV tax	345	
Total losses applied against Part IV tax		x 1 / 3 =

Part IV tax payable (enter amount on line 712 of the T2 return) 360

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

	A Name of connected recipient corporation 400	B Business Number 410	C Tax year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD (See note) 420	D Taxable dividends paid to connected corporations 430	D1 Eligible dividends (included in column D)
1	Haldimand County Utilities	86391 7795 RC0001	2012-12-31	611,329	

Note

If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information for each tax year of the recipient corporation. For more details, consult the Help.

Total 611,329

Total taxable dividends paid in the tax year to other than connected corporations 450

Eligible dividends (included in line 450) 450a

Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column D above **plus** line 450) 460 611,329

Part 4 – Total dividends paid in the tax year

Complete this part if the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460 above) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above) 611,329

Other dividends paid in the tax year (total of 510 to 540) . . . . .

Total dividends paid in the tax year 500 611,329

Deduct:

Dividends paid out of capital dividend account	510	
Capital gains dividends	520	
Dividends paid on shares described in subsection 129(1.2)	530	
Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year	540	
Subtotal		▶

Total taxable dividends paid in the tax year that qualify for a dividend refund 611,329

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Schedule 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2012-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations*.
- For more information, see the *T2 Corporation – Income Tax Guide*.
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 _____ Enter the Regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *	B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2*** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador 003 1 Yes ☐	103		143		
Newfoundland and Labrador offshore 004 1 Yes ☐	104		144		
Prince Edward Island 005 1 Yes ☐	105		145		
Nova Scotia 007 1 Yes ☐	107		147		
Nova Scotia offshore 008 1 Yes ☐	108		148		
New Brunswick 009 1 Yes ☐	109		149		
Quebec 011 1 Yes ☐	111		151		
Ontario 013 1 Yes ☐	113		153		
Manitoba 015 1 Yes ☐	115		155		
Saskatchewan 017 1 Yes ☐	117		157		
Alberta 019 1 Yes ☐	119		159		
British Columbia 021 1 Yes ☐	121		161		
Yukon 023 1 Yes ☐	123		163		
Northwest Territories 025 1 Yes ☐	125		165		
Nunavut 026 1 Yes ☐	126		166		
Outside Canada 027 1 Yes ☐	127		167		
Total	129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** If the corporation has income or loss from an international banking centre: the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*.

*** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
2,049,042		2,049,042	200,640

Ontario basic income tax (from Schedule 500)	270	235,640		
Deduct: Ontario small business deduction (from Schedule 500)	402	35,000		
	Subtotal	200,640	▶ 200,640	A6
Add:				
Surtax re Ontario small business deduction (from Schedule 500)	272			
Ontario additional tax re Crown royalties (from Schedule 504)	274			
Ontario transitional tax debits (from Schedule 506)	276			
Recapture of Ontario research and development tax credit (from Schedule 508)	277			
	Subtotal		▶	B6
		Subtotal (amount A6 **plus** amount B6)	200,640	C6
Deduct:				
Ontario resource tax credit (from Schedule 504)	404			
Ontario tax credit for manufacturing and processing (from Schedule 502)	406			
Ontario foreign tax credit (from Schedule 21)	408			
Ontario credit union tax reduction (from Schedule 500)	410			
Ontario transitional tax credits (from Schedule 506)	414	224		
Ontario political contributions tax credit (from Schedule 525)	415			
	Subtotal	224	▶ 224	D6
		Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")	200,416	E6
Deduct: Ontario research and development tax credit (from Schedule 508)	416			
Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0")			200,416	F6
Deduct: Ontario corporate minimum tax credit (from Schedule 510)	418			
Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0")			200,416	G6
Add:				
Ontario corporate minimum tax (from Schedule 510)	278			
Ontario special additional tax on life insurance corporations (from Schedule 512)	280			
Ontario capital tax (from Schedule 514 or Schedule 515, whichever applies)	282			
	Subtotal		▶	H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)			200,416	I6
Deduct:				
Ontario qualifying environmental trust tax credit	450			
Ontario co-operative education tax credit (from Schedule 550)	452	9,000		
Ontario apprenticeship training tax credit (from Schedule 552)	454	1,226		
Ontario computer animation and special effects tax credit (from Schedule 554)	456			
Ontario film and television tax credit (from Schedule 556)	458			
Ontario production services tax credit (from Schedule 558)	460			
Ontario interactive digital media tax credit (from Schedule 560)	462			
Ontario sound recording tax credit (from Schedule 562)	464			
Ontario book publishing tax credit (from Schedule 564)	466			
Ontario innovation tax credit (from Schedule 566)	468			
Ontario business-research institute tax credit (from Schedule 568)	470			
Other Ontario tax credits				
	Subtotal	10,226	▶ 10,226	J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.	290		190,190	K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits	255	190,190

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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SCHEDULE 6

SUMMARY OF DISPOSITIONS OF CAPITAL PROPERTY

Name of corporation	Business Number	Tax year-end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2012-12-31

- For use by corporations that have disposed of capital property or claimed an allowable business investment loss (ABIL), or both, in the tax year.
- Use this schedule to make a designation under paragraph 111(4)(e) of the federal *Income Tax Act* if control of the corporation has been acquired by a person or a group of persons.
- For more information, see the section called "Schedule 6, Summary of Dispositions of Capital Property" in the *T2 Corporation – Income Tax Guide*.

Designation under paragraph 111(4)(e) of the *Income Tax Act*

Are any dispositions shown on this schedule related to deemed dispositions designated under paragraph 111(4)(e)?

050 1 Yes [ ] 2 No [X] If yes, attach a statement specifying which properties are subject to such a designation.

Part 1 – Shares

No. of shares 100	Name of corporation 105	Class of shares 106	Date of acquisition YYYY/MM/DD 110	Proceeds of disposition 120	Adjusted cost base 130	Outlays and expenses (dispositions) 140	Gain (or loss) (column 120 minus cols. 130 and 140) 150	Foreign source
			Totals					

Total adjustment under subsection 112(3) of the Act to all losses identified in Part 1 160

Actual gain or loss from the disposition of shares (total of line 150 plus line 160) . . . . . A

Part 2 – Real estate (Do not include losses on depreciable property.)

	Municipal address 1 = Address 1 2 = Address 2 3 = City 4 = Province, Country, Postal Code and Zip Code or Foreign Postal Code 200	Date of acquisition YYYY/MM/DD 210	Proceeds of disposition 220	Adjusted cost base 230	Outlays and expenses (dispositions) 240	Gain (or loss) (column 220 minus cols. 230 and 240) 250	Foreign source
1	71 Selkirk St Caledonia		98,913	3,733		95,180	
2	325 Concession 2 Jarvis		11,791	407		11,384	
	Totals		110,704	4,140		106,564	B

Part 3 – Bonds

Face value 300	Maturity date 305	Name of issuer 307	Date of acquisition YYYY/MM/DD 310	Proceeds of disposition 320	Adjusted cost base 330	Outlays and expenses (dispositions) 340	Gain (or loss) (column 320 minus cols. 330 and 340) 350	Foreign source
			Totals					C

Part 4 – Other properties (Do not include losses on depreciable property.)

Description 400	Date of acquisition YYYY/MM/DD 410	Proceeds of disposition 420	Adjusted cost base 430	Outlays and expenses (dispositions) 440	Gain (or loss) (column 420 minus cols. 430 and 440) 450	Foreign source
Totals						D

Note:
Other property includes capital debts established as bad debts, as well as amounts that arise from foreign currency transactions.

Part 5 – Personal-use property (Do not include listed personal property.)

Description 500	Date of acquisition YYYY/MM/DD 510	Proceeds of disposition 520	Adjusted cost base 530	Outlays and expenses (dispositions) 540	Gain only (column 520 minus cols. 530 and 540) 550	Foreign source
Totals						E

Note:
You cannot deduct losses on dispositions of personal-use property (other than listed personal property) from your income.

Part 6 – Listed personal property

Description 600	Date of acquisition YYYY/MM/DD 610	Proceeds of disposition 620	Adjusted cost base 630	Outlays and expenses (dispositions) 640	Gain (or loss) (column 620 minus cols. 630 and 640) 650	Foreign source
Totals						

Subtract: Unapplied listed personal property losses from other years 655

Net gains (or losses) F

Note:
Net listed personal property losses can only be applied against listed personal property gains.

The amount on line 655 is from line 530 in Part 5 of Schedule 4, *Corporation Loss Continuity and Application.*

Part 7 – Determining allowable business investment losses

Property qualifying for and resulting in an allowable business investment loss

Name of small business corporation 900	Shares, enter 1; debt, enter 2 905	Date of acquisition YYYY/MM/DD 910	Proceeds of disposition 920	Adjusted cost base 930	Outlays and expenses (dispositions) 940	Loss only (column 920 minus cols. 930 and 940) 950	Foreign source
Totals							G

ABILs ..... Amount G _____ x 50.0000 % = _____ H

(enter amount H on line 406 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*)

Note:
Properties listed in Part 7 should not be included in any other parts of Schedule 6.

Part 8 – Determining capital gains or losses

Total of amounts A to F (do not include F if the amount is a loss) ..... 106,564 I

Add: Foreign source

Capital gains dividend received in the year ..... 875 _____ J ☐

Capital gains reserve opening balance (from Schedule 13) ..... 880 _____ K

Subtotal (add amounts I, J, and K) 106,564 L

Deduct:

Capital gains reserve closing balance (from Schedule 13) ..... 885 _____ M

Capital gains or losses, excluding ABILs (amount L minus amount M) 890 106,564

Part 9 – Determining taxable capital gains and total capital losses

Capital gains or losses, excluding ABILs (amount from line 890 above) . . . . . 106,564 N

Deduct the following gains that are included in amount N:

Gain on donation of a share, debt obligation, or right listed on a designated stock exchange and other amounts under paragraph 38(a.1) of the Act

realized before May 2, 2006 . . . . . _____ x 50.0000 % = _____ O Foreign source ☐

realized after May 1, 2006 . . . . . _____ P Foreign source ☐

Subtotal (O plus P) 895 _____

Gain on donation of ecologically sensitive land

realized before May 2, 2006 . . . . . _____ x 50.0000 % = _____ Q Foreign source ☐

realized after May 1, 2006 . . . . . _____ R Foreign source ☐

Subtotal (Q plus R) 896 _____

Exempt portion of the gain on the donation of securities arising from the exchange of a partnership interest under paragraph 38(*a.3*) . . . . . _____ R-2 Foreign source ☐

Total (line 895 **plus** line 896 **plus** line R-2) _____ S

Total capital gains or losses (amount N **minus** amount S) 106,564 T

Note:
If amount T is a loss, enter it on line 210 of Schedule 4.

Taxable capital gains: If amount T is a gain, enter it on this line and **multiply** . . . 106,564 x 50.0000 % = 53,282 U

(Enter amount U on line 113 of Schedule 1.)

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SCHEDULE 7

Aggregate Investment Income and Active Business Income

Corporation's name	Business Number	Tax year-end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2012-12-31

- This schedule is for the use of Canadian-controlled private corporations to calculate:
  - aggregate investment income and foreign investment income for the purpose of determining the refundable portion of Part I tax, as defined in subsection 129(4) of the *Income Tax Act;*
  - specified partnership income for members of one or more partnership(s); and
  - income from an active business carried on in Canada for the small business deduction.
- For more information, see the sections called "Small Business Deduction" and "Refundable Portion of Part I Tax" in the guide T4012, *T2 Corporation – Income Tax Guide.*

Part 1 – Aggregate investment income calculation

The aggregate investment income is the aggregate world source income.

The eligible portion of taxable capital gains included in income for the year . . . . . 002 53,282 A

Deduct:

Eligible portion of allowable capital losses for the year (including allowable business investment losses) . . . . . 012 _____ a

Net capital losses of other years claimed on line 332 on the T2 return . . . . . 022 _____ b

Amount a **plus** amount b _____ ▶ _____ B

Amount A **minus** amount B (if negative, enter "0") 53,282 C

Total income from property (include income from a specified investment business carried on in Canada other than income from a source outside Canada) . . . . . 032 _____ c

Deduct:

Exempt income . . . . . 042 _____ 1

Amounts received from AgriInvest Fund No. 2 that were included in computing the corporation's income for the year . . . . . 052 _____ 2

Taxable dividends deductible (total of Column F on Schedule 3) . . . . . 062 _____ 3

Business income from an interest in a trust that is considered property income under paragraph 108(5)(a) . 072 _____ 4

Total of amounts 1 to 4 _____ ▶ _____ d

Subtotal (amount c **minus** amount d) _____ ▶ _____ D

Amount C **plus** amount D 53,282 E

Total losses from property (include losses from a specified investment business carried on in Canada other than a loss from a source outside Canada) . . . . . 082 _____ F

Amount E **minus** amount F (if negative, enter "0") . . . . . 092 53,282 G

Enter amount G on line 440 of the T2 return.

Part 2A – Canadian investment income calculation

Eligible portion of taxable capital gains included in the income for the year before taking into account the capital gains reserve (federal) of Schedule 13 . . . . . 53,282 1.1

Reserve's eligible portion (addition/deduction) . . . . . _____ 1.2

The eligible portion of taxable capital gains included in income for the year after taking into account the capital gains reserve (federal) of Schedule 13 (total of amounts 1.1 and 1.2) . . . . . 53,282 ▶ 53,282 1a

Deduct:

Eligible portion of allowable capital losses for the year (including allowable business investment losses) . . . . . _____ 2a

Net capital losses of other years claimed on line 332 on the T2 return . . . . . _____ 3a

Total of amounts 2a and 3a _____ ▶ _____ 4a

Amount 1a **minus** amount 4a (if negative, enter "0") 53,282 5a

Part 2A – Canadian investment income calculation (continued)

Taxable dividends	6.1		
Real estate rental properties (under regulation 1100(11))	6.2		
ıer property income	6.3		
Total income from property from a source **Canadian**	▶		6a
Deduct:			
Exempt income	7a		
Amounts received from AgriInvest Fund No. 2 that were included in computing the corporation's income for the year	8a		
Taxable dividends deductible (total of Column F on Schedule 3)	9a		
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a)	10a		
Total of amounts 7a to 10a	▶		11a
Amount 6a **minus** amount 11a			12a
Amount 5a **plus** amount 12a		53,282	13a
Losses from rental properties (under regulation 1100(11))	14.1		
Other losses from property	14.2		
Total losses from property from a source **Canadian**	▶		14a
Amount 13a **minus** amount 14a (if negative, enter "0")		53,282	15a

Part 2 – Foreign investment income calculation

The foreign investment income is all income from sources **outside of Canada.**

Eligible portion of taxable capital gains included in the income for the year before taking into account the capital gains reserve (federal) of Schedule 13	H1				
Reserve's eligible portion (addition/deduction)	H2				
The eligible portion of taxable capital gains included in income for the year after taking into account the capital gains reserve (federal) of Schedule 13 (total of amounts H1 and H2)	▶		001		H
jible portion of allowable capital losses for the year (including allowable business investment losses)			009		I
Subtotal (amount H **minus** amount I) (if negative, enter "0")					J
Taxable dividends	e1				
Real estate rental properties (under regulation 1100(11))	e2				
Other property income	e3				
Total income from property from a source **outside Canada**	▶		019		e
Deduct:					
Exempt income	029			5	
Taxable dividends deductible (total of Column F on Schedule 3)	049			6	
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a)	059			7	
Total of amounts 5 to 7	▶			f	
Subtotal (amount e **minus** amount f)	▶				K
Amount J **plus** amount K					L
Losses from rental properties (under regulation 1100(11))	M1				
Other losses from property	M2				
Total losses from property from a source **outside Canada**	▶		069		M
Amount L **minus** amount M (if negative, enter "0")			079		N

(enter amount N on line 445 of the T2 return)

Net taxable dividends	Canadian	Foreign	Total
Taxable dividends deducted per schedule 3			
Less: Expenses related to such dividends			
Total expenses			
Net taxable dividends			

Part 3 – Specified partnership income

A Partnership name 200	B Total income (loss) of partnership from an active business 300	C Corporation's share of amount in column B 310

D Adjustments (add or deduct the prorated amounts calculated under section 34.2* and deduct expenses incurred by the corporation to earn partnership income) 315	E Corporation's income (loss) of the partnership (column C plus column D) 320	F Number of days in the partnership's fiscal period 325	G Prorated business limit (column C ÷ column B) x [$500,000 x (column F ÷ 365)] (if column C is negative, enter "0")** 330	H Column E minus column G (if negative, enter "0") 385	I Lesser of columns E and G (if column E is negative, enter "0") 340
Total	350			Total	360

Corporation's losses for the year from an active business carried on in Canada (other than as a member of a partnership) – enter as a positive amount . . . . . 370 _____ g

Specified partnership loss of the corporation for the year – enter as a positive amount (total of all negative amounts in column E) . . . . . 380 _____ h

Subtotal (amount g plus amount h) _____ i

Amount at line 385 or amount i, whichever is less . . . . . 390 _____ O

Specified partnership income (line 360 plus amount O) . . . . . 400 _____ P

Enter amount P at line T in Part 4.

* In general, amounts included or deducted under subsections 34.2(2), 34.2(3), 34.2(4), 34.2(11), and 34.2(12) are deemed to have the same **character** and be in the **same proportions** as the partnership income to which they relate. For example, if a corporation receives $100,000 of partnership income for the partnership's fiscal period ending in its tax year, and that income is made up of $40,000 of active business income, $30,000 of income from property, and $30,000 as a taxable capital gain, the corporation's adjusted stub period accrual (ASPA) in respect of the partnership would be 40% active business income, 30% property income, and 30% taxable capital gains. Add or deduct **only the proportion** of the following amounts that is deemed under subsection 34.2(5) to be **active business income:**

add:

- the ASPA under subsection 34.2(2) (column 4 of Schedule 73);
- the income inclusion for a new corporate member of a partnership under subsection 34.2(3) (column 6 of Schedule 73);
- the previous-year transitional reserve under subsection 34.2(12) (column 12 of Schedule 73);

deduct:

- the previous-year ASPA under subsection 34.2(4) (column 5 of Schedule 73);
- the previous-year income inclusion for a new corporate member of a partnership under subsection 34.2(4) (column 7 of Schedule 73); and
- the current-year transitional reserve under subsection 34.2(11) (column 11 of Schedule 73).

When a partnership carries on more than one business, one of which generates income and another of which realizes a loss, the loss is not netted against the partnership's income for the purpose of calculating the prorated business limit in column G. Enter on line h the total of all loss from column E.

Part 4 – Determination of partnership income

Corporation's share of partnership income from active businesses carried on in Canada after deducting related expenses – from line 350 in Part 3 (if the net amount is negative, enter "0" on line U)			Q
Add:			
ecified partnership loss (from amount h in Part 3)			R
Subtotal (amount Q **minus** amount R)			S
Deduct:			
Specified partnership income (from amount P in Part 3)			T
Partnership income (amount S **minus** amount T) (enter on line Y in Part 5)	450		U

Part 5 – Income from active business carried on in Canada

Net income for income tax purposes from line 300 of the T2 return				2,049,042 V
Deduct:				
Foreign business income after deducting related expenses*	500		j	
Taxable capital gains **minus** allowable capital loss (amount A **minus** amount a* in Part 1)**		53,282	k	
Net property income [amount c **minus** (amounts 1, 2, and F* in Part 1)]			l	
Personal services business income after deducting related expenses*	520		m	
Total of amounts j to m		53,282 ▶		53,282 W
Net amount (line V **minus** line W)				1,995,760 X
Deduct:				
Partnership income (line U in Part 4)				Y
Income from active business carried on in Canada (amount X **minus** amount Y) (enter amount Z on line 400 of the T2 return - if negative, enter "0")				1,995,760 Z

* If negative **add** instead of **subtracting**.

** This amount may only be negative to the extent of any allowable business investment losses.

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2012-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes ☐ 2 No ☒

	1 Class number (See Note) 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % **** 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ***** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1.	8		939,764	194,375		0	97,188	1,036,951	20	0	0	207,390	926,749
2.	10		734,548	186,784		6,983	89,901	824,448	30	0	0	247,334	667,015
3.	1		23,007,819	22,502		0	11,251	23,019,070	4	0	0	920,763	22,109,558
4.	17	Parking Lot	52,939			0		52,939	8	0	0	4,235	48,704
5.	45		6,047			0		6,047	45	0	0	2,721	3,326
6.	46		138			0		138	30	0	0	41	97
7.	47		18,166,914	4,616,474		1,898	2,307,288	20,474,202	8	0	0	1,637,936	21,143,554
8.	50		63,240	118,989		0	59,495	122,734	55	0	0	67,504	114,725
9.	1b	March 2007 Buildings	67,496			0		67,496	6	0	0	4,050	63,446
10.	12			128,623		0		128,623	100	0	0	128,623	
		Totals	43,038,905	5,267,747		8,881	2,565,123	45,732,648				3,220,597	45,077,174

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only, if you are using the declining balance method. For any other method (for example the straignt-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

Tax return

Additions for tax purposes – Schedule 8 regular classes			5,267,747	
Additions for tax purposes – Schedule 8 leasehold improvements		+		
Operating leases capitalized for book purposes		+		
Capital gain deferred		+		
Recapture deferred		+		
Deductible expenses capitalized for book purposes – Schedule 1		+		
Other (specify):				
Smart meter added to S8 in prior years, but added to FS in 2012		+	3,932,462	
Spares capitalized but not included on S8		+	-44,633	
	Total additions per books	=	9,155,576 ▶	9,155,576
Proceeds up to original cost – Schedule 8 regular classes			8,881	
Proceeds up to original cost – Schedule 8 leasehold improvements		+		
Proceeds in excess of original cost – capital gain		+		
Recapture deferred – as above		+		
Capital gain deferred – as above		+		
Pre V-day appreciation		+		
Other (specify):				
CONTRIBUTIONS IN AID		+	-29,125	
	Total proceeds per books	=	-20,244 ▶	-20,244
Depreciation and amortization per accounts – Schedule 1				– 3,940,606
Loss on disposal of fixed assets per accounts				–
Gain on disposal of fixed assets per accounts				+ 5,972
	Net change per tax return			= 5,241,186

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value			44,903,583
Opening net book value		–	39,662,400
	Net change per financial statements	=	5,241,183

If the amounts from the tax return and the financial statements differ, explain why below.

Difference due to roundung

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

me of corporation	Business Number	Tax year end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2012-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	HALDIMAND COUNTY ENERGY INC		89076 2412 RC0001	3					
2.	HALDIMAND COUNTY GENERATION		89075 7412 RC0001	3					
3.	HALDIMAND COUNTY UTILITIES IN		86391 7795 RC0001	1	1,001	100.000			17,144,796

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

Canada

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

e of corporation	Business Number	Tax year end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2012-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide.*
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0") 200 238,637 A

Add:

Cost of eligible capital property acquired during the taxation year . . . . . 222 _____

Other adjustments . . . . . 226 _____

Subtotal (line 222 plus line 226) _____ x 3 / 4 = _____ B

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 . . 228 _____ x 1 / 2 = _____ C

amount B minus amount C (if negative, enter "0") _____ ▶ _____ D

Amount transferred on amalgamation or wind-up of subsidiary . . . . . 224 _____ E

Subtotal (add amounts A, D, and E) 230 238,637 F

Deduct:

Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year . . . . . 242 _____ G

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) . . . . . 244 _____ H

Other adjustments . . . . . 246 _____ I

(add amounts G,H, and I) _____ x 3 / 4 = 248 _____ J

Cumulative eligible capital balance (amount F minus amount J) . . . . . 238,637 K

(If amount K is negative, enter "0" at line M and proceed to Part 2)

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business . . . . . 249 _____

amount K 238,637

less amount from line 249 _____

Current year deduction . . . . . 238,637 x 7.00 % = 250 16,705 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 16,705 ▶ 16,705 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") . . . . . 300 221,932 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)				N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988	400		1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)	401		2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402		3	
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408		4	
Line 3 minus line 4 (if negative, enter "0")		▶	5	
Total of lines 1, 2 and 5			6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400			7	
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000			8	
Subtotal (line 7 plus line 8)	409	▶	9	
Line 6 minus line 9 (if negative, enter "0")			▶	O
Line N minus line O (if negative, enter "0")				P
Line 5 _____ x 1 / 2 =				Q
Line P minus line Q (if negative, enter "0")				R
Amount R _____ x 2 / 3 =				S
Amount N or amount O, whichever is less				T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)	410			

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SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)
2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 – Associated non-CCPC
5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2006	maximum $300,000
2007	$300,001 to $400,000

Calendar year	Acceptable range
2008	maximum $400,000
2009	$400,001 to $500,000

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . . 025 — Year Month Day

Enter the calendar year to which the agreement applies . . . . . 050 — Year: 2012

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . 075 — 1 Yes ☐ 2 No ☒

	1 Names of associated corporations 100	2 Business Number of associated corporations 200	3 Association code 300	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % 350	6 Business limit allocated* $ 400
1	HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	1	500,000	100.0000	500,000
2	HALDIMAND COUNTY ENERGY INC.	89076 2412 RC0001	1	500,000		
3	HALDIMAND COUNTY GENERATION INC.	89075 7412 RC0001	1	500,000		
4	HALDIMAND COUNTY UTILITIES INC.	86391 7795 RC0001	1	500,000		
				Total	100.0000	500,000 A

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

Canada

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SCHEDULE 31

INVESTMENT TAX CREDIT – CORPORATIONS

General information

1. For use by a corporation that during a tax year:
   - earned an investment tax credit (ITC);
   - is claiming a deduction against its Part I tax payable;
   - is claiming a refund of credit earned during the current tax year;
   - is claiming a carryforward of credit from previous tax years;
   - is transferring a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1) of the federal *Income Tax Act;*
   - is requesting a credit carryback; or
   - is subject to a recapture of ITC.
2. References to parts, sections, and subsections on this schedule are from the federal *Income Tax Act* and the federal *Income Tax Regulations.* References to interpretation bulletins and information circulars are to the latest versions.
3. The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward.
4. Investments or expenditures, as defined in subsection 127(9) and Part XLVI of the federal *Income Tax Regulations*, that earn the ITC are:
   - qualified property (Parts 4 to 7);
   - expenditures that are part of the SR&ED qualified expenditure pool (Parts 8 to 17). Complete and file Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*;
   - pre-production mining expenditures (Parts 18 to 20);
   - apprenticeship job creation expenditures (Parts 21 to 23); and
   - child care spaces expenditures (Parts 24 to 28).
5. Attach a completed copy of this schedule with the *T2 Corporation Income Tax Return.*
6. For more information on ITCs, see the section called "Investment Tax Credit" in the *T2 Corporation – Income Tax Guide,* Information Circular IC 78-4, *Investment Tax Credit Rates,* and its related Special Release. Also, see Interpretation Bulletin IT-151, *Scientific Research and Experimental Development Expenditures.*
7. For information on SR&ED, see Interpretation Bulletin IT-151 **(consolidated)**, *Scientific Research and Experimental Development Expenditures*; Information Circular 86-4, *Scientific Research and Experimental Development*; Brochure RC4472, *Overview of the Scientific Research and Experimental Development Program (SR&ED) Tax Incentive Program*; Brochure RC4467, *Support for your R&D in Canada* and T4088, *Guide to Form T661 Scientific Research and Experimental Development (SR&ED) Expenditures Claim.*

Detailed information

1. For the purpose of this schedule, **"investment"** means:
   The capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
2. An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces the capital cost of that property in the next tax year. It also reduces the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
3. Property acquired has to be "available for use" before a claim for an ITC can be made.
4. Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which the expenditures or capital costs were incurred.
5. Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITC's is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 of the Act is not applicable for the agreement to share any income or loss. Special rules apply to specified and limited partners. For more information, see Guide T4068-1, 2010 Supplement to the 2006 T4068, Guide for the T5013 Partnership Information Return.
6. For SR&ED expenditures, the expression "in Canada" includes the "exclusive economic zone" (as defined in the *Oceans Act* to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone.

Name of corporation	Business Number	Tax year-end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2012-12-31

Part 1 – Investments, expenditures and percentages

	Specified percentage
Investments	
Qualified property acquired primarily for use in Newfoundland and Labrador, Prince Edward Island, Nova Scotia, New Brunswick, the Gaspé Peninsula, or a prescribed offshore region	10 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than the corporation's expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate.	
If you are a corporation that is not a CCPC that incurred qualified expenditures for SR&ED in any area in Canada	20 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures	
Before January 1, 2013	10 %
In 2013	5 %
After December 31, 2013	0 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment	10 %
If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? **101** 1 Yes ☐ 2 No ☒

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and the taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC calculating a refundable ITC, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;

b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or

c) any combination of persons referred to in a) or b) above.

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? **102** 1 Yes ☐ 2 No ☒

Contributions to agricultural organizations for SR&ED **103** _____

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in. For more information on Schedule 125, see the *Guide to the General Index of Financial Information (GIFI) for Corporations.*

ter contributions on line 350 of Part 8.

QUALIFIED PROPERTY

Part 4 – Eligible investments for qualified property from the current tax year

	CCA* class number 105	Description of investment 110	Date available for use 115	Location used (province or territory) 120	Amount of investment 125
1.					

* CCA: capital cost allowance

Total investment – enter in formula on line 240 in Part 5

Part 5 – Calculation of current-year credit and account balances – ITC from investments in qualified property

ITC at the end of the previous tax year

Deduct:

Credit deemed as a remittance of co-op corporations 210

Credit expired 215

Subtotal ▶

ITC at the beginning of the tax year 220

Add:

Credit transferred on amalgamation or wind-up of subsidiary 230

ITC from repayment of assistance 235

Total current-year credit: total of column 125 _____ x 10 % = 240

Credit allocated from a partnership 250

Subtotal ▶

Total credit available

Deduct:

Credit deducted from Part I tax (enter on line B1 in Part 30) 260

Credit carried back to the previous year(s) (from Part 6) A

Credit transferred to offset Part VII tax liability 280

Subtotal ▶

Credit balance before refund B

Deduct:

Refund of credit claimed on investments from qualified property (from Part 7) 310

ITC closing balance of investments from qualified property 320

Part 6 – Request for carryback of credit from investments in qualified property

	Year	Month	Day		
1st previous tax year				Credit to be applied	901
2nd previous tax year				Credit to be applied	902
3rd previous tax year				Credit to be applied	903

Total (enter on line A in Part 5)

Part 7 – Calculation of refund for qualifying corporations on investments from qualified property

Current-year ITCs (total of lines 240 and 250 in Part 5) C

Credit balance before refund (amount B from Part 5) D

Refund (40 % of amount C or D, whichever is less) E

Enter amount E or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if the corporation does not claim an SR&ED ITC refund).

SR&ED

Part 8 – Qualified SR&ED expenditures

ent expenditures

Current expenditures (from line 557 on Form T661)		
Add:		
Contributions to agricultural organizations for SR&ED*		
Current expenditures (including contributions to agricultural organizations for SR&ED at line 103 in Part 3)* (from line 557 on Form T661)	350	
Capital expenditures (from line 558 on Form T661)	360	
Repayments made in the year (from line 560 on Form T661)	370	
Total (this must equal the amount from line 570 on Form T661)*	380	

* Do not file form T661 if you are only claiming contributions made to agricultural organizations for SR&ED.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if the corporation is a CCPC.

Note: A CCPC that calculates SR&ED expenditure limit, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? 385 1 Yes ☐ 2 No ☒

Complete lines 390 and 398, if you answered no to the question at line 385 above or if the corporation is not associated with any other corporations (the amounts for associated corporations will be determined on Schedule 49).

Enter your taxable income for the previous tax year* (prior to any loss carry-backs applied).	390	3,957,886
Enter your taxable capital employed in Canada for the previous tax year minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million. 34,299,428	398	24,299,428

* If either of the tax years referred to at line 390 is less than 51 weeks, multiply the taxable income by the following result: 365 divided by the number of days in these tax years.

Part 10 – Calculation of SR&ED expenditure limit for a CCPC

For stand-alone corporations:

Calculation 1A: Tax year ends before January 1, 2010.

[($7,000,000 **minus** (10 x (line 390 from Part 9 or $400,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)] . . . . . _____

Calculation 1: Tax year starts after December 31, 2009.

[($8,000,000 **minus** (10 x (line 390 from Part 9 or $500,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)] . . . . . _____

Calculation 2: Tax year straddles January 1, 2010.

EE + [(FF **minus** EE) x (GG **divided by** HH)] where, ... _____

EE = [($7,000,000 **minus** (10A)) x (($40,000,000 **minus** B) **divided by** $40,000,000)];

FF = [($8,000,000 **minus** (10 x (line 390 from Part 9 or $500,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)];

GG = number of days in the tax year after December 31, 2009;

HH = number of days in the tax year.

Amount A **408** _____ Amount B **409** _____

A = the greater of:

- $400,000; and
- your taxable income for the last tax year* ending in the previous calendar year (tax years ending in 2008) (prior to any loss carry-backs applied).

B = the taxable capital employed in Canada for the last tax year ending in the previous calendar year (tax years ending in 2008) minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million.

* If any of the tax years referred to in A above are less than 51 weeks, gross up the taxable incomes for those tax years by the ratio that 365 is of the number of days in those tax years. Use these grossed up amounts when calculating the expenditure limit.

Enter the amount from Calculation 1A, 1 or 2, whichever is applicable _____ G*

For associated corporations:

ssociated, the allocation of the SR&ED expenditure limit as provided on Schedule 49 . . . . . **400** _____ H*

Where the tax year of the corporation is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Line G or H _____ x Number of days in the tax year _____ / 365 = 366 . . . . . _____ I

Your SR&ED expenditure limit for the year (enter the amount from line G, H, or I, whichever applies) . . . . . **410** _____

* Amount G or H cannot be more than $3,000,000.

Part 11 – Calculation of investment tax credits on SR&ED expenditures

Enter whichever is less: current expenditures (line 350 from Part 8) or the expenditure limit (line 410 from Part 10)* . . . . . 420 _____ x 35 % = _____ J

Line 350 minus line 410 (if negative, enter "0") . . . . . 430 _____ x 20 % = _____ K

Line 410 minus line 350 (if negative, enter "0") . . . . . _____ L

Enter whichever is less: capital expenditures (line 360 from Part 8) or line L above* . . . . . 440 _____ x 35 % = _____ M

Line 360 minus line L (if negative, enter "0") . . . . . 450 _____ x 20 % = _____ N

Repayments (amount from line 370 in Part 8) . . . . . _____

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit at the rate that would have applied to the repaid amount. Enter the amount of the repayment on the line that corresponds to the appropriate rate.

460 _____ x 35 % = _____

480 _____ x 20 % = _____

Total _____ ▶ _____ O

Current-year SR&ED ITC (total of lines J, K, M, N, and O; enter on line 540 in Part 12) . . . . . _____

* For corporations that are not CCPCs, enter "0" on lines J and M.

Part 12 – Calculation of current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year . . . . . _____

Deduct:

Credit deemed as a remittance of co-op corporations . . . . . 510 _____

Credit expired . . . . . 515 _____

Subtotal _____ ▶ _____

ITC at the beginning of the tax year . . . . . 520 _____

Add:

Credit transferred on amalgamation or wind-up of subsidiary . . . . . 530 _____

Total current-year credit . . . . . 540 _____

Credit allocated from a partnership . . . . . 550 _____

Subtotal _____ ▶ _____

Total credit available . . . . . _____

Deduct:

Credit deducted from Part I tax (enter on line B2 in Part 30) . . . . . 560 _____

Credit carried back to the previous year(s) (from Part 13) . . . . . _____ P

Credit transferred to offset Part VII tax liability . . . . . 580 _____

Subtotal _____ ▶ _____

Credit balance before refund . . . . . _____ Q

Deduct:

Refund of credit claimed on expenditures of SR&ED (from Part 14 or 15, whichever applies) . . . . . 610 _____

ITC closing balance on SR&ED . . . . . 620 _____

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day
1st previous tax year			
2nd previous tax year			
3rd previous tax year			

. . . . . Credit to be applied 911 _____

. . . . . Credit to be applied 912 _____

. . . . . Credit to be applied 913 _____

Total (enter on line P in Part 12) _____

Part 14 – Calculation of refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined at line 101.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? 650 1 Yes ☐ 2 No ☒

Credit balance before refund (amount Q from Part 12) _____ R

Current-year ITC (lines 540 plus 550 from Part 12 **minus** line O from Part 11) _____ S

Refundable credits (amount R or S, whichever is less)* _____ T

Amount J from Part 11 _____ U

Subtract: Amount T or U, whichever is less _____ V

Net amount (if negative, enter "0") _____ W

Amount W _____ x 40 % _____ X

Add: Amount V _____ Y

Refund of ITC (amounts X **plus** Y – enter this, or a lesser amount, on line 610 in Part 12) _____ Z

Enter the total of lines 310 from Part 5 and 610 from Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation [as defined in subsection 127.1(2)], this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC on line Z.

Part 15 – Calculation of refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined in Part 2.

Credit balance before refund (amount Q from Part 12) _____ AA

Amount J from Part 11 _____ BB

Subtract: Amount AA or BB, whichever is less _____ CC

Net amount (if negative, enter "0") _____ DD

Amount M from Part 11 _____ EE

Amount DD or EE, whichever is less _____ x 40 % _____ FF

Add : Amount CC above _____ GG

Refund of ITC (amounts FF **plus** GG) _____ HH

Enter HH, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

RECAPTURE – SR&ED

Part 16 – Calculating the recapture of ITC for corporations and corporate partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, if the credit was earned in a tax year ending after 1997 and did not expire before 2008;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

Note:

The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

	Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the note above **700**	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710**	Amount from column 700 or 710, whichever is less
1.			

Subtotal (enter this amount on line LL in Part 17) _____ II

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil at line JJ in Part 16.

	A Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement **720**	B Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition **730**	C Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) **740**
1.			

Calculation 2 (continued) – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil on line JJ below.

	D Amount determined by the formula (A x B) – C	E ITC earned by the transferee for the qualified expenditures that were transferred **750**	F Amount from column D or E, whichever is less
1.			

Subtotal (enter this amount on line MM in Part 17) _____ JJ

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line KK below.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported on line NN in Part 17) **760** _____ KK

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC for calculation 1 from line II in Part 16		LL
Recaptured ITC for calculation 2 from line JJ in Part 16 above		MM
Recaptured ITC for calculation 3 from line KK in Part 16 above		NN
Total recapture of SR&ED investment tax credit – Add lines LL, MM and NN		OO

Enter amount OO at line A1 in Part 29.

PRE-PRODUCTION MINING

Part 18 – Pre-production mining expenditures

Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

	List of minerals 800
1.	

For each of the minerals reported in column 800 above, identify each project, mineral title, and mining division where title is registered. If there is no mineral title, identify the project and mining division only.

	Project name 805	Mineral title 806	Mining division 807
1.			

Pre-production mining expenditures *

Pre-production mining expenditures that the corporation incurred in the tax year for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting	810	PP
Geological, geophysical, or geochemical surveys	811	QQ
Drilling by rotary, diamond, percussion, or other methods	812	RR
Trenching, digging test pits, and preliminary sampling	813	SS

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping	820	TT
Sinking a mine shaft, constructing an adit, or other underground entry	821	UU

Other pre-production mining expenditures incurred in the tax year:

	Description 825	Amount 826
1.		

Add amounts at column 826 ▶ VV

Total pre-production mining expenditures (add amounts PP to VV) 830

Deduct: Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line 830 above 832

Excess (line 830 minus line 832) (if negative, enter "0") WW

Add: Repayments of government and non-government assistance 835 XX

Pre-production mining expenditures (amount WW plus amount XX) YY

A pre-production mining expenditure is defined under subsection 127(9).

Part 19 – Calculation of current-year credit and account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year

Deduct:

Credit deemed as a remittance of co-op corporations — 841

Credit expired — 845

Subtotal

ITC at the beginning of the tax year — 850

Add:

Credit transferred on amalgamation or wind-up of subsidiary — 860

Expenditures from line YY in Part 18:

Expenditures incurred before January 1, 2013		x 10 %	=		1
Expenditures incurred in 2013		x 5 %	=		2
Expenditures incurred after December 31, 2013		x 0 %	=		3
Add lines 1, 2 and 3 — 870					880

Total credit available

Deduct:

Credit deducted from Part I tax (enter on line B3 in Part 30) — 885

Credit carried back to the previous year(s) (from Part 20) — CCC

Subtotal

ITC closing balance from pre-production mining expenditures — 890

Part 20 – Request for carryback of credit from pre-production mining expenditures

	Year	Month	Day		
1st previous tax year				Credit to be applied	921
2nd previous tax year				Credit to be applied	922
previous tax year				Credit to be applied	923

Total (enter on line CCC in Part 19)

APPRENTICESHIP JOB CREATION

Part 21 – Calculation of total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number or name) appears below? (If not, you cannot claim the tax credit.) — 611 — 1 Yes ☐ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the social insurance number (SIN) or the name of the eligible apprentice. Attach additional schedules if more space is needed.

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
1.	[redacted]	POWERLINE TECHNICIAN	3,502	350	350
				Total current-year credit (enter at line 640)	350

* Net of any other government or non-government assistance received or to be received.

Part 22 – Calculation of current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year				
Deduct:				
Credit deemed as a remittance of co-op corporations	612			
Credit expired after 20 tax years	615			
Subtotal			▶	
ITC at the beginning of the tax year			625	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	630			
ITC from repayment of assistance	635			
Total current-year credit (total of column 605)	640	350		
Credit allocated from a partnership	655			
Subtotal		350	▶	350
Total credit available				350
Deduct:				
Credit deducted from Part I tax (enter on line B4 in Part 30)	660	350		
Credit carried back to the previous year(s) (from Part 23)			DDD	
Subtotal		350	▶	350
ITC closing balance from apprenticeship job creation expenditures			690	

Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	931	
2nd previous tax year				Credit to be applied	932	
3rd previous tax year				Credit to be applied	933	
				Total (enter on line DDD in Part 22)		

CHILD CARE SPACES

Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that the corporation incurred to create licensed child care spaces for the children of the employees and, potentially, for other children. The corporation cannot be carrying on a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures;

acquired or incurred only to create new child care spaces at a licensed child care facility.

Cost of depreciable property from the current tax year

	CCA* class number 665	Description of investment 675	Date available for use 685	Amount of investment 695
1.				

Total cost of depreciable property from the current tax year 715 — EEE

Add: Specified child care start-up expenditures from the current tax year 705 — FFF

Total gross eligible expenditures for child care spaces (line 715 **plus** line 705) — GGG

Deduct: Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line GGG) 725 — HHH

Excess (amount GGG **minus** amount HHH) (if negative, enter "0") — III

i: Repayments of government and non-government assistance 735 — JJJ

Total eligible expenditures for child care spaces (amount III **plus** amount JJJ) 745

* CCA: capital cost allowance

Part 25 – Calculation of current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (line 745)			x	25 %	=		KKK
Number of child care spaces	755		x	$ 10,000	=		LLL
ITC from child care spaces expenditures (amount KKK or LLL, whichever is less)							MMM

Part 26 – Calculation of current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year			
Deduct:			
Credit deemed as a remittance of co-op corporations	765		
Credit expired after 20 tax years	770		
Subtotal		▶	
ITC at the beginning of the tax year	775		
Add:			
Credit transferred on amalgamation or wind-up of subsidiary	777		
Total current-year credit (amount MMM above)	780		
Credit allocated from a partnership	782		
Subtotal		▶	
Total credit available			
Deduct:			
Credit deducted from Part I tax (enter on line B5 in Part 30)	785		
Credit carried back to the previous year(s) (from Part 27)			NNN
Subtotal		▶	
ITC closing balance from child care spaces expenditures	790		

Part 27 – Request for carryback of credit from child care space expenditures

	Year	Month	Day			
1st previous tax year	2011-12-31			Credit to be applied	941	
2nd previous tax year	2010-12-31			Credit to be applied	942	
3rd previous tax year	2009-12-31			Credit to be applied	943	
				Total (enter on line NNN in Part 26)		

RECAPTURE – CHILD CARE SPACES

Part 28 – Calculating the recapture of ITC for corporations and corporate partnerships – Child care spaces

ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

- the new child care space is no longer available; or
- property that was an eligible expenditure for the child care space is:
  - disposed of or leased to a lessee; or
  - converted to another use.

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) . . . . . 792 _____ ZZZ

In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:

The amount that can reasonably be considered to have been included in the original ITC . . . . 795 _____

25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property . . . . . 797 _____

Amount from line 795 or line 797, whichever is less . . . . . _____ OOO

Corporate partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line PPP below.

Corporate partner's share of the excess of ITC 799 _____ PPP

Total recapture of child care spaces investment tax credit – Add lines ZZZ, OOO, and PPP or amount QQQ on line A2 in Part 29. . . . . _____ QQQ

Part 29 – Total recapture of investment tax credit

Recaptured SR&ED ITC from line OO in Part 17 . . . . . _____ A1

Recaptured child care spaces ITC from line QQQ in Part 28 above . . . . . _____ A2

Total recapture of investment tax credit – Add lines A1 and A2 . . . . . _____ A3

Enter amount A3 on line 602 of the T2 return.

Part 30 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5) . . . . . _____ B1

ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12) . . . . . _____ B2

ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19) . . . . . _____ B3

ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22) 350 B4

ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26) . . . . . _____ B5

Total ITC deducted from Part I tax (add lines B1, B2, B3, B4, and B5) 350 B6

Enter amount B6 at line 652 of the T2 return.

Privacy Act, Personal Information Bank number CRA PPU 047

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CA class number 97 Apprenticeship job creation ITC

Current year

	Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
	350	350			

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2011-12-31				
2010-12-31				
2009-12-31				
2008-12-31				
2007-12-31				
2006-12-31				
2005-12-31				
2004-12-31				
2003-12-31				*
2002-12-31				
2001-12-31				
2001-09-30				
2000-12-31				
1999-12-31				
1998-12-31				
1997-12-31				
1996-12-31				
1995-12-31				
1994-12-31				
1993-12-31				*
Total				

B+C+D+G **Total ITC utilized** 350

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit will only expire at the beginning of the subsequent fiscal period. Consequently, this amount will be posted on line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 of the subsequent fiscal year.

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SCHEDULE 50

SHAREHOLDER INFORMATION

e of corporation	Business Number	Tax year end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2012-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

		Provide only one number per shareholder				
	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Business Number (If a corporation is not registered, enter "NR") 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	HALDIMAND COUNTY UTILITIES INC.	86391 7795 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

ıe of corporation	Business Number	Tax year-end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2012-12-31

On: 2012-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 — 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? ☒ Yes ☐ No
   If the answer to question 3 is yes, complete Part "GRIP addition for 2006".

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? ☒ Yes ☐ No

   Corporations that become a CCPC or a DIC ☐ Yes ☒ No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation ☐ Yes ☒ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Corporations that wound-up a subsidiary ☐ Yes ☒ No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? ☐ Yes ☐ No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? ☐ Yes ☐ No
    If the answer to question 11 is yes, complete Part 3.

Part 1 – Calculation of general rate income pool (GRIP)

GRIP at the end of the previous tax year			100	19,946,360 A
Taxable income for the year (DICs enter "0") *	110	2,049,042 B		
Income for the credit union deduction * (amount E in Part 3 of Schedule 17)	120			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less *	130			
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income *	140	53,282		
Subtotal (add lines 120, 130, and 140)		53,282 ▶	53,282 C	
Income taxable at the general corporate rate (line B **minus** line C) (if negative enter "0")	150	1,995,760		
After-tax income (line 150 x general rate factor for the tax year ** 0.72)			190	1,436,947 D
Eligible dividends received in the tax year	200			
Dividends deductible under section 113 received in the tax year	210			
Subtotal (add lines 200 and 210)		▶		E
GRIP addition:				
Becoming a CCPC (line PP from Part 4)	220			
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)	230			
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)	240			
Subtotal (add lines 220, 230, and 240)		▶	290	F
Subtotal (add lines A, D, E, and F)			21,383,307	G
Eligible dividends paid in the previous tax year	300			
Excessive eligible dividend designations made in the previous tax year	310			
Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.				
Subtotal (line 300 **minus** line 310)		▶		H
GRIP before adjustment for specified future tax consequences (line G **minus** line H) (amount can be negative)			490	21,383,307
GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2)			560	
GRIP at the end of the tax year (line 490 **minus** line 560)			590	21,383,307

Enter this amount on line 160 of Schedule 55.

* For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

** **The general rate factor** for a tax year is 0.68 for any portion of the tax year that falls before 2010, 0.69 for any portion of the tax year that falls in 2010, 0.70 for any portion of the tax year that falls in 2011, and 0.72 for any portion of the tax year that falls after 2011. Calculate the general rate factor in Part 5 for tax years that straddle these dates.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

First previous tax year 2011-12-31

Taxable income before specified future tax consequences from the current tax year	3,957,886 J1		
Enter the following amounts before specified future tax consequences from the current tax year:			
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	K1		
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	L1		
Aggregate investment income (line 440 of the T2 return)	M1		
Subtotal (add lines K1, L1, and M1)	▶	N1	
Subtotal (line J1 **minus** line N1) (if negative, enter "0")	3,957,886 ▶		3,957,886 O1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less R1

Aggregate investment income (line 440 of the T2 return) S1

Subtotal (add lines Q1, R1, and S1) ▶ T1

Subtotal (line P1 **minus** line T1) (if negative, enter "0") ▶ U1

Subtotal (line O1 **minus** line U1) (if negative, enter "0") V1

GRIP adjustment for specified future tax consequences to the first previous tax year

(line V1 **multiplied by** the general rate factor for the tax year 0.72) 500

Second previous tax year 2010-12-31

Taxable income before specified future tax consequences from the current tax year 5,212,348 J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less L2

Aggregate investment income (line 440 of the T2 return) M2

Subtotal (add lines K2, L2, and M2) ▶ N2

Subtotal (line J2 **minus** line N2) (if negative, enter "0") 5,212,348 ▶ 5,212,348 O2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less R2

Aggregate investment income (line 440 of the T2 return) S2

Subtotal (add lines Q2, R2, and S2) ▶ T2

Subtotal (line P2 **minus** line T2) (if negative, enter "0") ▶ U2

Subtotal (line O2 **minus** line U2) (if negative, enter "0") V2

GRIP adjustment for specified future tax consequences to the second previous tax year

V2 **multiplied by** the general rate factor for the tax year 0.72) 520

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2009-12-31

Taxable income before specified future tax consequences from current tax year 4,744,105 J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . _____ K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . _____ L3

Aggregate investment income (line 440 of the T2 return) 1,965 M3

Subtotal (add lines K3, L3, and M3) 1,965 ▶ 1,965 N3

Subtotal (line J3 **minus** line N3) (if negative, enter "0") 4,742,140 ▶ 4,742,140 O3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . . _____ P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . _____ Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . _____ R3

Aggregate investment income (line 440 of the T2 return) . . . . . _____ S3

Subtotal (add lines Q3, R3, and S3) _____ ▶ _____ T3

Subtotal (line P3 **minus** line T3) (if negative, enter "0") _____ ▶ _____ U3

Subtotal (line O3 **minus** line U3) (if negative, enter "0") _____ V3

GRIP adjustment for specified future tax consequences to the third previous tax year
(line V3 **multiplied** by the general rate factor for the tax year 0.72) . . . . . 540 _____

Total GRIP adjustment for specified future tax consequences to previous tax years:
(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . . _____ W

Enter amount W on line 560.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

nb. 1 Post amalgamation . . . ☐ Post wind-up . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . . . _____ AA

Eligible dividends paid by the corporation in its last tax year . . . . . _____ BB

Excessive eligible dividend designations made by the corporation in its last tax year . . . . . _____ CC

Subtotal (line BB **minus** line CC) _____ ▶ _____ DD

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)
(line AA **minus** line DD) . . . . . _____ EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

1 Corporation becoming a CCPC ☐ Post amalgamation ☐ Post wind-up ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year ..... FF

The corporation's money on hand immediately before the end of its previous/last tax year ..... GG

Unused and unexpired losses at the end of the corporation's previous/last tax year:

Non-capital losses .....
Net capital losses .....
Farm losses .....
Restricted farm losses .....
Limited partnership losses .....

Subtotal ▶ HH

Subtotal (add lines FF, GG, and HH) II

All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year ..... JJ

Paid-up capital of all the corporation's issued and outstanding shares apital stock immediately before the end of its previous/last tax year ..... KK

All the corporation's reserves deducted in its previous/last tax year LL

The corporation's capital dividend account immediately before the end of its previous/last tax year ..... MM

The corporation's low rate income pool immediately before the end of its previous/last tax year ..... NN

Subtotal (add lines JJ, KK, LL, MM, and NN) ▶ OO

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC (line II **minus** line OO) (if negative, enter "0") ..... PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 5 – General rate factor for the tax year

Complete this part to calculate the general rate factor for the tax year.

0.68	x	number of days in the tax year before January 1, 2010 / number of days in the tax year	366	.....	=		QQ
0.69	x	number of days in the tax year in 2010 / number of days in the tax year	366	.....	=		RR
0.7	x	number of days in the tax year in 2011 / number of days in the tax year	366	.....	=		SS
0.72	x	number of days in the tax year after December 31, 2011 / number of days in the tax year	366 / 366	.....	=	0.72000	TT

General rate factor for the tax year (total of lines QQ to TT) ..... 0.72000 UU

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SCHEDULE 55

PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

e of corporation	Business Number	Tax year-end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2012-12-31

Do not use this area

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation*, or Schedule 54, *Low Rate Income Pool (LRIP) Calculation*, whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- All legislative references on this schedule are to the federal *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3			
Taxable dividends paid in the tax year **included** in Schedule 3		611,329	
Total taxable dividends paid in the tax year	100	611,329	
Total eligible dividends paid in the tax year	150		A
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")	160	21,383,307	B
Excessive eligible dividend designation (line 150 **minus** line 160)			C
Deduct:			
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends*	180		D
Subtotal (amount C **minus** amount D)			E
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (amount E **multiplied** by 20 %)	190		F

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3			
Taxable dividends paid in the tax year **included** in Schedule 3			
Total taxable dividends paid in the tax year	200		
Total excessive eligible dividend designations in the tax year (amount from line A of Schedule 54)			G
Deduct:			
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends*	280		H
Subtotal (amount G **minus** amount H)			I
Part III.1 tax on excessive eligible dividend designations – Other corporations (amount I **multiplied** by 20 %)	290		J

Enter the amount from line 290 on line 710 of the T2 return.

You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax. For more information on how to make this election, go to **www.cra.gc.ca/eligibledividends**.

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SCHEDULE 500

ONTARIO CORPORATION TAX CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2012-12-31

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- This schedule is a worksheet only and does not have to be filed with your *T2 Corporation Income Tax Return*.

Part 1 – Calculation of Ontario basic rate of tax for the year

Number of days in the tax year before July 1, 2010 / Number of days in the tax year		366	x 14.00 % =	%	A1
Number of days in the tax year after June 30, 2010, and before July 1, 2011 / Number of days in the tax year		366	x 12.00 % =	%	A2
Number of days in the tax year after June 30, 2011 / Number of days in the tax year	366	366	x 11.50 % =	11.50000 %	A3

Ontario basic rate of tax for the year (total of rates A1 to A3) 11.50000 ▶ 11.50000 % A4

Part 2 – Calculation of Ontario basic income tax

Ontario taxable income * . . . . . 2,049,042 B

Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A4 from Part 1) . . . . . 235,640 C

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit, in addition to Ontario basic income tax, or has Ontario corporate minimum tax, Ontario special additional tax on life insurance corporations or Ontario capital tax payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

Income from active business carried on in Canada (amount from line 400 of the T2 return)				1,995,760	1
Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return)				2,049,042	2
Federal business limit before the application of subsection 125(5.1) * (amount from line 410 of the T2 return)		x	=	500,000	3
			line 4 on page 4 of the T2 return		
Enter the least of amounts 1, 2, and 3				500,000	D
Ontario domestic factor:	Ontario taxable income ** / taxable income earned in all provinces and territories ***	2,049,042.00 / 2,049,042	=	1.00000	E

Amount D x amount E: 500,000 a

Ontario taxable income (amount B from Part 2): 2,049,042 b

Ontario small business income (lesser of amount a and amount b) ..... 500,000 F

Number of days in the tax year before July 1, 2010 / Number of days in the tax year	/ 366	x	8.50 %	= %	G1
Number of days in the tax year after June 30, 2010, and before July 1, 2011 / Number of days in the tax year	/ 366	x	7.50 %	= %	G2
Number of days in the tax year after June 30, 2011 / Number of days in the tax year	366 / 366	x	7.00 %	= 7.00000 %	G3

OSBD rate for the year (total of rates G1 to G3) ..... 7.00000 % G4

Ontario small business deduction: amount F **multiplied** by OSBD rate for the year (rate G4) ..... 35,000 H

Enter amount H on line 402 of Schedule 5.

* For 2011 and later tax years, enter the amount from line 410 of the T2 return on line 3 of this schedule. Otherwise, complete the calculation for this line.

** Enter amount B from Part 2.

*** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Part 4 – Calculation of surtax re Ontario small business deduction

Complete this part if the corporation is claiming the OSBD and its adjusted taxable income, **plus** the adjusted taxable income of each corporation with which the corporation was associated during its tax year, is greater than $500,000. If the corporation is a member of an associated group, complete Schedule 501, *Ontario Adjusted Taxable Income of Associated Corporations to Determine Surtax re Ontario Small Business Deduction.*

Note: For days in the tax year after June 30, 2010, the small business surtax rate is 0%. You do not have to complete this part if the corporation's tax year begins after June 30, 2010.

Adjusted taxable income * I

Adjusted taxable income of all associated corporations (amount from line 500 of Schedule 501) ..... J

Aggregate adjusted taxable income (amount I **plus** amount J) ..... ▶ K

Deduct:

Ontario business limit 500,000

Subtotal (amount K **minus** Ontario business limit) (if negative, enter "0" on this line and on line P) L

Small business surtax rate for the year:

Number of days in the tax year before July 1, 2010 / Number of days in the tax year ____ / 366 x 4.25 % = ____ % M

Amount L **multiplied by** % on line M = ... N

Amount N ____ x Ontario small business income (amount F from Part 3) / 500,000 ____ / 500,000 = ... O

Surtax re Ontario small business deduction: lesser of amount O and OSBD (amount H from Part 3) ..... P

Enter amount P on line 272 of Schedule 5.

* Adjusted taxable income is equal to the corporation's taxable income or taxable income earned in Canada for the year **plus** the amount of the corporation's adjusted Crown royalties for the year **minus** the amount of the corporation's notional resource allowance for the year (from Schedule 504, *Ontario Resource Tax Credit and Ontario Additional Tax re Crown Royalties*).

If the tax year of the corporation is less than 51 weeks, **multiply** the adjusted taxable income of the corporation for the year by 365 and **divide** by the number of days in the tax year.

Part 5 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Lesser of amount D and amount b from Part 3 ..... 500,000 Q

Surtax payable (amount P from Part 4) / Ontario domestic factor (amount E from Part 3) x OSBD rate (rate G4 from Part 3) ____ / 7.00000 % / 0.07000 = ____ R

Note: Enter "0" on line R for tax years beginning after June 30, 2010.

Ontario adjusted small business income (amount Q **minus** amount R) (if negative, enter "0") ..... 500,000 S

Enter amount S on line U in Part 6 or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 6 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

ınt D from Part 3 of Schedule 17		T
Deduct:		
Ontario adjusted small business income (amount S from Part 5)		U
Subtotal (amount T **minus** amount U) (if negative, enter "0")		V
OSBD rate for the year (rate G4 from Part 3)	7.00000 %	
Amount V **multiplied** by the OSBD rate for the year		W
Ontario domestic factor (amount E from Part 3)	1.00000	X
Ontario credit union tax reduction (amount W **multiplied** by amount X)		Y

Enter amount Y on line 410 of Schedule 5.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 506

ONTARIO TRANSITIONAL TAX DEBITS AND CREDITS

e of corporation	Business Number	Tax year-end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2012-12-31

- Complete this schedule if you are a specified corporation that is subject to the Ontario transitional tax debit or are claiming the Ontario transitional tax credit.
- Unless otherwise noted, all legislative references are to the federal *Income Tax Act*.
- File this schedule with the *T2 Corporation Income Tax Return*.
- Unless otherwise noted, terms on this page are defined under subsection 46(1) of the *Taxation Act, 2007* (Ontario).
- **Specified corporation** is defined under subsection 46(5) of the *Taxation Act, 2007* (Ontario) as a corporation:
  - that is not exempt at or immediately before its transition time from tax payable under Part I of the federal Act;
  - that has a tax year that ends before 2009 and a tax year that includes January 1, 2009; or has a tax year that begins after 2008 and a tax year that is deemed to end on December 31, 2008, under subsection 249(3) of the federal Act;
  - that has a permanent establishment (PE) in Ontario at its transition time;
  - that had a PE in Ontario at any time in its last tax year ending before 2009, and was subject to tax under Part II of the *Corporations Tax Act* (Ontario) for that tax year; and
  - whose assets have not been distributed in an eligible pre-2009 windup.
- A specified corporation also includes, under subsection 51(1) of *the Taxation Act, 2007* (Ontario), the parent corporation of an eligible post-2008 windup and the new corporation of an eligible amalgamation.
- A specified corporation may be subject to the Ontario transitional tax debit if:
  - the corporation's total federal balance is more than the total Ontario balance at the end of the tax year; or
  - the corporation has a post-2008 scientific research and experimental development (SR&ED) balance, as defined under subsection 49(2) of the *Taxation Act, 2007* (Ontario), and a federal SR&ED transitional balance, as defined under subsection 49(4) of the *Taxation Act, 2007* (Ontario), at the end of the tax year.
- A specified corporation may be able to claim the Ontario transitional tax credit if:
  - the corporation's total Ontario balance is more than the total federal balance at the end of the tax year; or
  - the corporation has an unused transitional tax credit balance from previous tax years.
- **Transition time** means:
  - the beginning of the corporation's first tax year that starts after 2008 if the previous tax year is deemed under subsection 249(3) of the federal Act to end on December 31, 2008, or
  - the beginning of the corporation's tax year that includes January 1, 2009, in any other case.
- An **eligible amalgamation** means an amalgamation or merger of a particular corporation and one or more other corporations to form a new corporation where:
  - the amalgamation or merger occurs after December 31, 2008, and does not occur at the new corporation's transition time;
  - the new corporation has a PE in Ontario immediately after the amalgamation or merger;
  - the particular corporation has a PE in Ontario immediately before the amalgamation or merger;
  - the particular corporation is a specified corporation at its transition time or at any time before the amalgamation or merger;
  - the amalgamation or merger occurs in the amortization period of the new corporation;
  - the amortization period of the new corporation does not end immediately after the beginning of its reference period; and
  - the amortization period of the particular corporation does not end before the amalgamation or merger.
- An **eligible post-2008 windup** means the windup of a subsidiary corporation into its parent corporation under subsection 88(1) where:
  - the completion time of the windup is after December 31, 2008, and the time immediately after the completion time is within the amortization periods of the subsidiary and parent;
  - the parent's tax year (during which it received the assets of the subsidiary) ends after December 31, 2008;
  - the subsidiary has a PE in Ontario during its tax year ending at the completion time; and
  - the parent has a PE in Ontario during its tax year in which it received the assets from the subsidiary.
- An **eligible pre-2009 windup** means the windup of a subsidiary under subsection 88(1) where:
  - the completion time of the windup is after December 31, 2008, and the parent's tax year (during which it received the assets of the subsidiary) ended before January 1, 2009; or
  - the completion time of the windup is before January 1, 2009, and the parent's tax year (during which it received the assets of the subsidiary) ended after December 31, 2008.
- The **completion time** of a windup means the end of the tax year of the subsidiary during which the subsidiary distributes its assets to the parent for the purposes of paragraph 88(1)(e.2).
- A **specified pre-2009 transfer** under section 52 of the *Taxation Act, 2007* (Ontario) means a transfer of property between corporations not at arm's length that changes the total federal or Ontario balance of either the transferee or the transferor and that occurs:
  - before 2009;
  - at different values under the *Corporations Tax Act* (Ontario) and the federal Act;
  - in a tax year ending after 2008 for either the transferee or the transferor corporation, and that corporation is a specified corporation; and
  - in a tax year of the other corporation ending before 2009, in which the other corporation has a PE in Ontario.

Part 1 – Total federal balance

Complete this part if:

– the tax year includes January 1, 2009; or

– the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

If this is the first year after amalgamation, include the total of all amounts from the predecessor corporations that had a PE in Ontario immediately before the amalgamation.

If the corporation is a life insurer or a non-resident corporation, do not include the amounts under the additional rules in subsection 48(8) of the *Taxation Act, 2007* (Ontario).

For other tax years, go to Part 3.

Federal balances at the end of the previous tax year (tax year ending in 2008)

Total undepreciated capital cost of depreciable properties (total of column 220 from Schedule 8, *Capital Cost Allowance (CCA)*)	110	
Charitable donations not yet deducted from income (from line 280 of Schedule 2, *Charitable Donations and Gifts*) (see Note 1)	112	
Gifts to Canada, a province, or a territory (from line 380 of Schedule 2) (see Note 1)	114	
Gifts of certified cultural property (from line 480 of Schedule 2) (see Note 1)	116	
Gifts of certified ecologically sensitive land (from line 580 of Schedule 2) (see Note 1)	118	
Gifts of medicine (from line 680 of Schedule 2) (see Note 1)	120	
Cumulative eligible capital (from line 300 of Schedule 10, *Cumulative Eligible Capital Deduction*)	122	
Federal SR&ED expenditure pool (from line 470 of Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*) (see Note 2 and Note 3)	124	
Cumulative Canadian exploration expense (from line 249 of Schedule 12, *Resource-Related Deductions*) (see Note 2)	128	
Cumulative Canadian development expense (from line 349 of Schedule 12) (see Note 2)	130	
Cumulative Canadian oil and gas property expense (from line 449 of Schedule 12) (see Note 2)	132	

Federal balances at the beginning of the current tax year

Non-capital losses (line 102 of Schedule 4, *Corporation Loss Continuity and Application*, of the current tax year) (see Note 2 and Note 4)	134	
Capital losses (from line 200 of Schedule 4 of the current tax year x 50 %) (see Note 2 and Note 4)	136	

Amounts included in the calculation of the Ontario income tax in the previous tax year

Total reserves deducted under paragraph 20(1)(l), (l.1), (m), (m.1), (n), or (o), subsection 32(1), section 61.4 or subparagraph 138(3)(a)(i), (ii), or (iv) of the federal Act, as it applies for the purposes of the *Corporations Tax Act* (Ontario)	150	
One half of the total reserves deducted under subparagraph 40(1)(a)(iii) or 44(1)(e)(iii) of the federal Act, as it applies under the *Corporations Tax Act* (Ontario)	152	
Other discretionary deductions claimed for Ontario income tax, but not claimed federally in the tax years ending after December 12, 2006, and before the transition time	154	

Other amounts

Total adjusted cost base of partnership interests owned by the corporation, under the federal Act, at the beginning of the tax year (see Note 5)	160	
Gain from a negative adjusted cost base of a partnership interest under subsection 40(3) of the federal Act, as it applies under the *Corporations Tax Act* (Ontario), as if all partnership interests were disposed of at the beginning of the tax year	162	
Amount of farming income specified under paragraph 28(1)(b) in the previous tax year	164	
Federal balance before election (total of lines 110 to 164)		A

Deduct:

Lesser of amount D or amount E from Part 4, if an election is made	170	
Total federal balance (amount A **minus** line 170)	180	

Enter amount on line 300 in Part 3.

Note 1: Enter "0" if the corporation was non-resident immediately before its transition time.

Note 2: Enter "0" if control of the corporation was acquired at transition time.

Note 3: Do not include the SR&ED expenditure pool earned before control of the corporation was last acquired.

Note 4: Do not include losses that arose before control of the corporation was last acquired.

Note 5: The adjusted cost base of any particular partnership interest cannot be less than "0".

Part 2 – Total Ontario balance

Complete this part if:

– the tax year includes January 1, 2009; or

– the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

If this is the first year after amalgamation, include the total of all amounts from the predecessor corporations that had a PE in Ontario immediately before the amalgamation.

If the corporation is a life insurer or a non-resident corporation, do not include the amounts under the additional rules in subsection 48(8) of the *Taxation Act, 2007* (Ontario).

For other tax years, go to Part 3.

Ontario balances at the end of the previous tax year (tax year ending in 2008)

Total undepreciated capital cost of depreciable properties (total of column 13 from Ontario Schedule 8, *Ontario Capital Cost Allowance*)	210	
Charitable donations (amount I from Ontario *Schedule 2, Ontario Charitable Donations and Gifts*) (see Note 1)	212	
Gifts to Canada, a province, or a territory (total of closing balance amounts from parts 3 and 5 of Ontario Schedule 2) (see Note 1)	214	
Gifts of certified cultural property (closing balance amount from Part 6 of Ontario Schedule 2) (see Note 1)	216	
Gifts of certified ecologically sensitive land (closing balance amount from Part 7 of Ontario Schedule 2) (see Note 1)	218	
Gifts of medicine (see Note 1)	220	
Cumulative eligible capital (amount Q from Ontario *Schedule 10, Ontario Cumulative Eligible Capital Deduction*)	222	
Ontario SR&ED expenditure pool (line 480 from Ontario *CT23 Schedule 161, Ontario Scientific Research and Experimental Development Expenditures*) (see Note 2 and Note 3)	224	
Adjusted Ontario SR&ED incentive balance (see Note 2 and Note 5)	226	
Cumulative Canadian exploration expense (closing balance of Regular Expenses from Part 2 of Ontario *Schedule 12, Ontario Exploration Expenses*) (see Note 2)	228	
Cumulative Canadian development expense (closing balance of Regular Expenses, Canadian CCDE Expenses, from Part 3 of Ontario Schedule 12) (see Note 2)	230	
Cumulative Canadian oil and gas property expense (closing balance of Regular Expenses from Part 4 of Ontario Schedule 12) (see Note 2)	232	
Non-capital losses (from line 709 of Ontario *Corporations Tax Return CT8* or *CT23 Corporations Tax Annual Return*) (see Note 2 and Note 4)	234	
Net capital losses (from line 719 of CT8 or CT23 x 50 %) (see Note 2 and Note 4)	236	

Amounts included in the calculation of the federal income tax in the previous tax year

Total reserves deducted under paragraph 20(1)(l), (l.1), (m), (m.1), (n), or (o), subsection 32(1), section 61.4 or subparagraph 138(3)(a)(i), (ii), or (iv)	250	
One half of the total reserves deducted under subparagraph 40(1)(a)(iii) or 44(1)(e)(iii)	252	

Other amounts

Total adjusted cost base of partnership interests owned by the corporation, for the purposes of the *Corporations Tax Act* (Ontario), at the beginning of the tax year (see Note 6)	260	
Gain from a "negative" adjusted cost base of a partnership interest under subsection 40(3) determined as if all partnership interests were disposed of at the beginning of the tax year	262	
Amount of farming income in the previous tax year specified under paragraph 28(1)(b) of the federal Act, as it applies for the purposes of the *Corporations Tax Act* (Ontario)	264	
Total Ontario balance (total of lines 210 to 264)	280	

Enter amount on line 340 in Part 3.

Note 1: Enter "0" if the corporation was non-resident immediately before its transition time.

Note 2: Enter "0" if control of the corporation was acquired at transition time.

Note 3: Do not include the SR&ED expenditure pool earned before control of the corporation was last acquired.

Note 4: Do not include losses that arose before control of the corporation was last acquired.

Note 5: The adjusted Ontario SR&ED incentive balance under subsection 49(7) of the *Taxation Act, 2007* (Ontario) is the total of federal investment tax credits that:

- have been earned and are available without restriction to the corporation;
- are attributable to qualifying Ontario SR&ED expenditures;
- have not been deducted under subsection 127(5) or (6) of the federal Act at the end of the corporation's tax year ending immediately before its transition time; and
- do not expire in the first tax year ending in 2009 under the 10-year carryforward limit,

divided by the relevant Ontario allocation factor as calculated in Part 11.

Note 6: The adjusted cost base of any particular partnership interest cannot be less than "0".

Part 3 – Total federal balance and total Ontario balance at the end of the tax year

Total federal balance:

Total federal balance (amount from line 180 in Part 1, or amount from line 330 in 3 of Schedule 506 for the previous tax year)	300	35,541,755		
Add:				
Amount from eligible amalgamation*	310			
Amount from eligible post-2008 windup*	315			
Amount from eligible pre-2009 windup*	320			
Amount from specified pre-2009 transfers*	325			
Total federal balance at the end of the tax year		35,541,755 ▶	330	35,541,755

Total Ontario balance:

Total Ontario balance (amount from line 280 in Part 2, or amount from line 370 in Part 3 of Schedule 506 for the previous tax year)	340	35,551,504		
Add:				
Amount from eligible amalgamation*	350			
Amount from eligible post-2008 windup*	355			
Amount from eligible pre-2009 windup*	360			
Amount from specified pre-2009 transfers*	365			
Total Ontario balance at the end of the tax year		35,551,504 ▶	370	35,551,504
Transitional balance at the end of the tax year (line 330 **minus** line 370)			390	-9,749

If line 390 is positive, the corporation may be subject to a transitional tax debit. Complete Part 7 of this schedule.
If line 390 is negative, the corporation may be eligible to claim a transitional tax credit. Complete Part 8 of this schedule.

* See page 1 for definitions of eligible amalgamation, eligible post-2008 windup, eligible pre-2009 windup, and specified pre-2009 transfers. To calculate these amounts, you can use *Schedule 507, Ontario Transitional Tax Debits and Credits Calculation.*

Part 4 – Election to reduce federal SR&ED expenditure pool

The corporation may make this election if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

Are you making an election under clause (b) of the definition of "I" in paragraph 1 of subsection 48(4) of the *Taxation Act, 2007* (Ontario)? 400 1 Yes ☐ 2 No ☒

If you answered **no** to the question at line 400, go to Part 5. If you answered **yes** to the question at line 400, complete the following calculation:

Federal SR&ED expenditure pool closing balance at the end of the previous tax year (amount from line 124 in Part 1) _____ B

Deduct:

Adjusted Ontario SR&ED incentive balance at the end of the previous tax year (amount from line 226 in Part 2) _____ 1

Ontario SR&ED expenditure pool closing balance at the end of the previous tax year (amount from line 224 in Part 2) _____ 2

Subtotal (amount 1 **plus** amount 2) ▶ _____ C

Subtotal (amount B **minus** amount C) (if negative, enter "0") _____ D

Federal balance before election (amount A from Part 1) _____

Deduct:

Total Ontario balance (amount from line 280 in Part 2) _____

Subtotal (if negative, enter "0") _____ E

Enter the lesser of amount D and amount E on line 170 in Part 1.

Part 5 – Reference period and amortization period

Reference period

The reference period starts at the beginning of the corporation's first tax year ending after December 31, 2008, and on whichever date is earlier:

- five calendar years after the time immediately before the start of the corporation's reference period; or
- December 31, 2013.

Number of days in the corporation's reference period* (do not include February 29, 2008, and February 29, 2012) . . **410** 1,825

* The number of days in the corporation's reference period is 1825 unless:

- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3). In this case, count the number of days from the beginning of the 2009 tax year to December 31, 2013; or
- the corporation was incorporated or amalgamated after January 1, 2009. In this case, count the number of days from the date of incorporation or date of amalgamation to December 31, 2013.

Amortization period

The amortization period starts at the beginning of the corporation's reference period and ends on whichever date is earlier:

- the end of the corporation's reference period; or
- the early termination date as indicated under line 430.

Number of days in the amortization period that are in the tax year** (do not include February 29, 2008, or February 29, 2012) **420** 365

** The number of days in the amortization period that are in the tax year is the number of days in the tax year unless:

- the tax year-end is later than the end of the reference period. In this case, count the number of days from the beginning of the tax year to the end of the reference period; or
- the corporation terminates the amortization period before the end of the tax year. In this case, count the number of days from the beginning of the tax year to the day of early termination.

Early termination of the amortization period

The amortization period of the corporation usually coincides with the corporation's reference period. However, if the corporation's amortization period ends in the tax year and before the reference period ends, tick the applicable box below to indicate the reason for the early termination.

430 The corporation:

1 ☐ – ceases to have a PE in Ontario in the tax year for any reason other than an eligible amalgamation or eligible post-2008 windup.

2 ☐ – becomes exempt from tax under Part I of the federal Act immediately after the end of the tax year.

3 ☐ – elects under subsection 47(2) of the *Taxation Act, 2007* (Ontario) to prepay the transitional tax debit.
Note: The Ontario Allocation Factor, calculated in Part 6, has to be at least 90% or the amount on line 390 in Part 3 is not more than $10,000.

4 ☐ – does not object to early termination of the amortization period and accelerated payment of the transitional tax credit, under subsection 46(3) of the *Taxation Act, 2007* (Ontario).
Note: Amount T in Part 8 cannot be more than $1,000.

If you ticked one of the above boxes:

- enter the date of the early termination, if the date is different from the tax year-end and you ticked box 1 at line 430 . . . . . **435** _____
- enter the number of days from the first day of the tax year to the end of the corporation's reference period (do not include February 29, 2008, or February 29, 2012) . . . . . **440** _____

Part 6 – Calculation of Ontario allocation factor (OAF)

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation and enter the result on line F:

Ontario taxable income* / Taxable income** = _____

Ontario allocation factor (OAF) . . . . . 1.00000 F

* Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If taxable income is nil, calculate the amount in column F as if taxable income were $1,000.

** Enter taxable income from line 360 or amount Z of the T2 return, whichever applies. If taxable income is nil, enter "1,000."

Part 7 – Transitional tax debits

Complete this part if the amount on line 390 in Part 3 is positive.

Amount from line 390 in Part 3			G
Amount G x Ontario basic rate of tax*	11.5 % =		H
Amount H x OAF (from line F in Part 6)	1.00000		I

Number of days from line 440 (if applicable) or line 420 in Part 5 / Number of days in the corporation's reference period from line 410 in Part 5: 365 / 1,825 = 0.20000 J

Transitional tax debit before tax on elected reduced SR&ED pool (amount I **multiplied** by amount J) K

Post-2008 SR&ED balance at the end of the year (amount HH from Part 12)	460	
Federal SR&ED transitional balance at the end of the year (amount QQ from Part 14)	470	

Tax on elected reduced SR&ED pool (the lesser of lines 460 and 470) L

Total transitional tax debits (amount K **plus** amount L) M

Enter amount M on line 276 of Schedule 5.

Part 8 – Transitional tax credits

Complete this part if the amount on line 390 in Part 3 is negative.

Amount C6 from Schedule 5: 200,640 N

Deduct:

Ontario resource tax credit (from line 404 of Schedule 5)		
Ontario tax credit for manufacturing and processing (from line 406 of Schedule 5)		
Ontario foreign tax credit (from line 408 of Schedule 5)		
Ontario credit union tax reduction (from line 410 of Schedule 5)		
Subtotal		O
Subtotal (amount N **minus** amount O)	200,640	P

Number of days from line 420 in Part 5 / Number of days in the tax year (do not include February 29, 2008, or February 29, 2012): 365 / 365 = 1.00000 Q

Ontario tax payable for purposes of the current year transitional tax credit (amount P **multiplied** by amount Q) 510 200,640

Amount from line 390 in Part 3 (enter as a positive amount)	9,749	R
Amount R x Ontario basic rate of tax* 11.5 % =	1,121	S
Amount S x OAF (from line F in Part 6)	1,121	T

Number of days from line 440 (if applicable) or line 420 in Part 5 / Number of days in the corporation's reference period on line 410 in Part 5: 365 / 1,825 = 0.20000 U

Current-year transitional tax credit (amount T **multiplied** by amount U) 520 224

Ontario tax payable for purposes of the unused transitional tax credit carryforward (line 510 **minus** line 520) (if negative, enter "0") 530 200,416

Transitional tax credit:

Lesser of amounts on line 510 and 520: 224 V

Lesser of unused transitional tax credit available (amount Y from Part 9) and amount on line 530 W

Transitional tax credits (amount V **plus** amount W): 224 X

Enter amount X on line 414 of Schedule 5.

* Enter the rate calculated in Part 1 of Schedule 500, *Ontario Corporation Tax Calculation.*

Part 9 – Unused transitional tax credit

Unused transitional tax credit carryforward from previous year (amount from line 580 of the previous year)* 1

Unused transitional tax credit transferred from a predecessor corporation or a subsidiary on an eligible amalgamation or an eligible post-2008 windup* 560 2

Unused transitional tax credit available (amount 1 **plus** amount 2) ..... Y

Add:

Current-year transitional tax credit (amount from line 520 in Part 8) ..... 224 Z

Subtotal (amount Y **plus** amount Z) 224 3

Deduct:

Transitional tax credit applied (amount X from Part 8) ..... 224 AA

Unused transitional tax credit (available for later years) (amount 3 **minus** amount AA) 580

* Enter "0" if this is the first tax year ending after 2008.

Complete parts 10 to 14 if the corporation or a predecessor made an election in Part 4 at the transition time.

Part 10 – Federal current SR&ED limit and federal current SR&ED deficit

Current SR&ED expenditures in the year under paragraph 37(1)(a) 610

Capital SR&ED expenditures in the year under paragraph 37(1)(b) 614

Repayment of assistance under paragraph 37(1)(c) 618

Investment tax credit recaptured under subsections 127(27), (29), and (34) in the previous tax year 624

Subtotal (total of lines 610 to 624) ..... BB

Deduct:

Assistance under paragraph 37(1)(d) 638

Investment tax credits deducted under paragraph 37(1)(e) 644

Subtotal (line 638 **plus** line 644) CC

Federal current SR&ED limit or federal current SR&ED deficit (amount BB **minus** amount CC) 650

If the amount on line 650 is positive, enter it on line II in Part 13.

If the amount on line 650 is negative, enter it as a positive amount on line DD in Part 12.

Part 11 – Relevant OAF

Enter on line 660 whichever of the following amounts is greatest:

- the corporation's OAF for the tax year that includes its transition time (from line F in Part 6) ..... %
- the greatest of the corporation's OAFs for a tax year ending in 2006, 2007, and 2008 as determined under subsection 12(1) of the *Corporations Tax Act* (Ontario) ..... %
- the greatest of the weighted OAFs* of the corporation and its designated corporations** for 2006, 2007, and 2008 ..... %

Relevant OAF ..... 660 %

* The weighted OAF for two or more corporations for their tax years ending in 2006, 2007, or 2008 is the total of the following for each corporation:

- the corporation's OAF as determined under subsection 12(1) of the *Corporations Tax Act* (Ontario) for the tax year **multiplied** by the corporation's and its share of partnerships' qualified Ontario SR&ED expenditures in the tax year, **divided** by the total of all the corporations' and their shares of partnerships' qualified Ontario SR&ED expenditures in the tax year.

Qualified Ontario SR&ED expenditure is defined in section 11.2 of the *Corporations Tax Act* (Ontario).

** A designated corporation in respect of a particular corporation is:

1) a corporation that amalgamated with the particular corporation under section 87;
2) a corporation that wound up into the particular corporation under subsection 88(1); or
3) a designated corporation to a corporation identified in 1) or 2).

Part 12 – Post-2008 SR&ED balance

Federal current SR&ED deficit for the year (amount from line 650 in Part 10, if negative) (enter as a positive amount) . . . . . DD

.ED expenditure amount deducted in the year under subsection 37(1) 670

Deduct:

Cumulative post-2008 SR&ED limit at the end of the year (amount LL from Part 13) 675

Subtotal (line 670 **minus** line 675) (if negative, enter "0") ▶ EE

Subtotal (amount DD **plus** amount EE) FF

Amount FF x 14 % GG

Post-2008 SR&ED balance at the end of the year (amount GG **multiplied** by line 660 from Part 11) . . . . . HH

Enter amount HH on line 460 in Part 7.

Part 13 – Cumulative post-2008 SR&ED limit at the end of the year

Federal current SR&ED limit for the year (amount from line 650 in Part 10, if positive) II

Total of all federal SR&ED limits from previous tax years ending after December 31, 2008 700

Subtotal (line II **plus** line 700) JJ

Total of all amounts deducted under subsection 37(1) for previous tax years ending after December 31, 2008 705

Total of all transitional tax debits on elected reduced SR&ED pool calculated under subsection 48(3) of the *Taxation Act, 2007* (Ontario) in the previous years (total of line L in Part 7 for previous years) 710

Deduct:

Amounts included in line 710 that are reasonably attributable to the federal current SR&ED deficit for the year 715

Subtotal (line 710 **minus** line 715) 720

Line 720 = ... KK

Relevant OAF (from line 660 in Part 11) x 14 %

Subtotal (line 705 **minus** amount KK) ▶ 730

Cumulative post-2008 SR&ED limit at the end of the year (amount JJ **minus** line 730) (if negative, enter "0") LL

Enter amount LL on line 675 in Part 12.

Part 14 – Federal SR&ED transitional balance at the end of the year

Amount from line 170 in Part 1 (see Note) . . . . . 735 MM

Relevant OAF (from line 660) (see Note) **multiplied** by amount MM . . . . . NN

Amount NN x 14 % . . . . . ▶ OO

Federal SR&ED transitional balance transferred on an eligible amalgamation or an eligible post-2008 wind-up 740

Subtotal (amount OO **plus** line 740) PP

Deduct:

Total of all transitional tax debits on elected reduced SR&ED pool calculated under subsection 48(3) of the *Taxation Act, 2007* (Ontario) in the previous years (total of line L in Part 7 for previous years) 750

Federal SR&ED transitional balance at the end of the year (amount PP **minus** line 750) . . . . . QQ

Enter amount QQ on line 470 in Part 7.

Note: For tax years ending after 2009, enter the amount from line 170 and the relevant OAF from the 2009 tax year.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2012-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
HALDIMAND COUNTY HYDRO INC.

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	**110** Date of incorporation or amalgamation, whichever is the most recent (Year Month Day)	**120** Ontario Corporation No.
Ontario	2000-10-13	00144779

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

Care of (if applicable)

210 Street number	**220** Street name/Rural route/Lot and Concession number	**230** Suite number
1	GREENDALE DRIVE RR #2	

240 Additional address information if applicable (line 220 must be completed first)

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
CALEDONIA	ON	CA	N3W 2J3

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 [1] If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 ALBERT (Last name) **451** R. JANE (First name)

454 _____ (Middle name(s))

460 [1] Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 ☐ Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)

520 Street number | **530** Street name/Rural route/Lot and Concession number | **540** Suite number

550 Additional address information if applicable (line 530 must be completed first)

560 Municipality (e.g., city, town) | **570** Province/state | **580** Country | **590** Postal/zip code

Part 6 – Language of preference

600 ☐ Indicate your language of preference by entering 1 for English or 2 for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 550

ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2012-12-31

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009; and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return.*
- File this schedule with the *T2 Corporation Income Tax Return.*

Part 1 – Corporate information

110 Name of person to contact for more information	120 Telephone number including area code
R. JANE ALBERT	(905) 765-5211

Is the claim filed for a CETC earned through a partnership?* ..... 150 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 150, what is the name of the partnership? ..... 160 _____

Enter the percentage of the partnership's CETC allocated to the corporation ..... 170 _____ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? ..... 200 1 Yes ☒ 2 No ☐
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? ..... 210 1 Yes ☐ 2 No ☒

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * . . . . . 300 _____

Eligible expenditures incurred before March 27, 2009:

- If line 300 is $400,000 or less, enter 15% on line 310.
- If line 300 is $600,000 or more, enter 10% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\% - \left[5\% \times \frac{\text{amount on line 300 minus } \$\ 400{,}000}{\$\ 200{,}000} \right]$$

Eligible percentage for determining the eligible amount . . . . . 310 15.000 %

For eligible expenditures incurred after March 26, 2009:

- If line 300 is $400,000 or less, enter 30% on line 312.
- If line 300 is $600,000 or more, enter 25% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\% - \left[5\% \times \frac{\text{amount on line 300 minus } \$\ 400{,}000}{\$\ 200{,}000} \right]$$

Eligible percentage for determining the eligible amount . . . . . 312 30.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as parate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then r that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
1.	CONTESTOGA COLLEGE	POWERLINE TECHNICIAN
2.	CONTESTOGA COLLEGE	POWERLINE TECHNICIAN
3.	MOHAWK COLLEGE	ELECTRICAL ENGINEERING TECH CONTROL

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
1.	[redacted]	2012-05-01	2012-08-31
2.	[redacted]	2012-04-30	2012-09-07
3.	[redacted]	2012-01-16	2012-12-31

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
1.		15.000 %	14,614	30.000 %		17
2.		15.000 %	13,448	30.000 %		19
3.		15.000 %	29,347	30.000 %		50

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
1.	4,384	3,000	3,000		3,000
2.	4,034	3,000	3,000		3,000
3.	8,804	3,000	3,000		3,000

Ontario co-operative education tax credit (total of amounts in column K) 500 **9,000** L

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L _____ x percentage on line 170 in Part 1 _____ % = ... M

...er amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one ...edule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009, and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received. Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 552

ONTARIO APPRENTICESHIP TRAINING TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2012-12-31

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. Before March 27, 2009, the maximum credit for each apprentice is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship. After March 26, 2009, the maximum credit for each apprentice is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. The maximum credit amount is prorated for an employment period of an apprentice that straddles March 26, 2009.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  - paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  - for services provided by the apprentice during the first 36 months of the apprenticeship program, if incurred before March 27, 2009; and
  - for services provided by the apprentice during the first 48 months of the apprenticeship program, if incurred after March 26, 2009.
- An expenditure is not eligible for an ATTC if:
  - the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  - it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  - the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario); and
  - the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009* or the *Apprenticeship and Certification Act, 1998* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act*.
- Make sure you keep a copy of the training agreement or contract of apprenticeship to support your claim. Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return*.
- File this schedule with your *T2 Corporation Income Tax Return*.

Part 1 – Corporate information (please print)

110 Name of person to contact for more information	120 Telephone number including area code
R. JANE ALBERT	(905) 765-5211

Is the claim filed for an ATTC earned through a partnership? * ..... 150 1 Yes ☐ 2 No ☒

If yes to the question at line 150, what is the name of the partnership? ..... 160 _____

Enter the percentage of the partnership's ATTC allocated to the corporation ..... 170 _____ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? ..... 200 1 Yes ☒ 2 No ☐
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? ..... 210 1 Yes ☐ 2 No ☒

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

Part 3 – Specified percentage

Corporation's salaries and wages paid in the previous tax year * 300 1,533,984

For eligible expenditures incurred before March 27, 2009:
- If line 300 is $400,000 or less, enter 30% on line 310.
- If line 300 is $600,000 or more, enter 25% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Specified percentage} = 30\% - \left[5\% \times \frac{\text{amount on line 300 minus } 400{,}000}{200{,}000} \right]$$

Specified percentage . . . . . 310 25.000 %

For eligible expenditures incurred after March 26, 2009:
- If line 300 is $400,000 or less, enter 45% on line 312.
- If line 300 is $600,000 or more, enter 35% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Specified percentage} = 45\% - \left[10\% \times \frac{\text{amount on line 300 minus } 400{,}000}{200{,}000} \right]$$

Specified percentage . . . . . 312 35.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario apprenticeship training tax credit

Complete a **separate entry** for each apprentice that is in a qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a **separate entry** for each repayment, and complete columns A to G and M and N with the details for the employment period in the previous tax year in which the government assistance was received.

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
1.	434a	Powerline Technician	[redacted]
2.			

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
1.	PG424	2012-11-13	2012-11-13	2012-12-31
2.				

Note 1: Enter the original registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the last day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

Part 4 – Calculation of the Ontario apprenticeship training tax credit (continued)

	H1 Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below) 441	H2 Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below) 442	H3 Number of days employed as an apprentice in the tax year (column H1 **plus** column H2) 440	I Maximum credit amount for the tax year (see note 2 below) 445
1.		48	48	1,311
2.				

	J1 Eligible expenditures before March 27, 2009 (see note 3 below) 451	J2 Eligible expenditures after March 26, 2009 (see note 3 below) 452	J3 Eligible expenditures for the tax year (column J1 **plus** column J2) 450	K Eligible expenditures **multiplied** by specified percentage (see note 4 below) 460
1.		3,502	3,502	1,226
2.				

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5 below) 480	N ATTC for each apprentice (column L or column M, whichever applies) 490
1.	1,226		1,226
2.			

Ontario apprenticeship training tax credit (total of amounts in column N) **500** 1,226 O

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O _____ x percentage on line 170 in Part 1 _____ % = ... _____ P

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, add the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.
For H1: The days employed as an apprentice must be within 36 months of the registration date provided in column E.
For H2: The days employed as an apprentice must be within 48 months of the registration date provided in column E.

Note 2: Maximum credit = ($5,000 x H1/365*) + ($10,000 x H2/365*)
* 366 days, if the tax year includes February 29

Note 3: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.
For J1: Eligible expenditures before March 27, 2009, must be for services provided by the apprentice during the first 36 months of the apprenticeship program.
For J2: Eligible expenditures after March 26, 2009, must be for services provided by the apprentice during the first 48 months of the apprenticeship program.

Note 4: Calculate the amount in column K as follows:
Column K = (J1 x line 310) + (J2 x line 312)

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year.
Complete a **separate entry** for each repayment of government assistance.

Continuity of Capital Dividend Account

2012-12-31 (see Note)

Capital gains

Non-taxable portion of capital gains realized in prior years		46,093	
Non-taxable portion of capital gains for the year	+	53,282	99,375

Capital losses

Non-deductible portion of capital losses incurred in prior years		24,795	
Non-deductible portion of capital losses for the year	+		
Non-deductible portion of business investment losses	+		24,795
Excess of non-taxable portion of gains over losses			74,580

Capital dividends received

Aggregate of dividends received in prior years			
Dividends received during the year	+		

Eligible capital property – Balance from prior years

Non-taxable portion of net proceeds on sale of E.C.P – Balance from prior years			

Life insurance policies

Proceeds from life insurance policies received in prior years			
Proceeds from life insurance policies received in year	+		
Adjusted cost base of life insurance policies disposed of in prior years	–		
Adjusted cost base of life insurance policies disposed of in year	–		

Capital gains paid out by a trust

taxable portion of capital gains paid out by a trust – Balance from prior years			
Non-taxable portion of capital gains paid out by a trust – for the current year	+		
Non-taxable dividends earned from a CDA and paid out by a trust – Balance from prior years			
Non-taxable dividends earned from a CDA and paid out by a trust – for the current year	+		

Capital dividend account balance before capital dividends paid or payable	74,580

Capital dividends paid or payable

Aggregate of dividends – prior years			
Dividends paid or payable for year	+		

Eligible capital property

Disposition incurred during the taxation year ending after October 17, 2000

Amount to be included under subsection 14 (1)(b). Amount from line S on Schedule 10 for the taxation years ending after October 17, 2000 – for the current year			
Appropriate portion of amount deducted as a credit loss (paragraph 20(4.2)) or capital losses (paragraph 20(4.3)) for the taxation years ending after October 17, 2000 – for the current year	–		
Non-taxable portion of sale of E.C.P.			

Capital dividend account balance	74,580

Balance of the capital dividend account at the end of the preceding taxation year

Balance of the capital dividend account on 2011-12-31	21,298

Note: The time period in which the CDA applies commences on the first day of the first taxation year ending after 1971 and after the corporation last became a private corporation and ends immediately before the balance in the CDA is to be determined.

Exhibit 5 – Cost of Capital and Capital Structure

	Tab	Schedule	Appendix
Overview	1	1	
Capital Structure		2	
Cost of Debt		3	
Return on Equity		4	

OVERVIEW

The purpose of this Exhibit is to summarize the method and cost of financing Haldimand County Hydro Inc.'s ("HCHI's") capital requirements for the 2014 Test Year and to support the rate of return on rate base of 5.75% as shown in this Exhibit at Tab 1, Schedule 2.

Capital Structure

HCHI has a current deemed capital structure of 60% debt – 56% long-term with a return of 5.13% and 4% short-term with a return of 2.07% - and 40% equity with a rate of return of 9.85%, consistent with the capital structure and return approved in HCHI's 2010 COS rate application (EB-2009-0265).

HCHI has prepared this Application with a capital structure of 60% debt – 56% long-term with a return of 3.70% and 4% short-term with a return of 2.07% – and 40% equity with a return of 8.98%.

Cost of Debt

Long-Term Debt

For the 2014 Test Year, HCHI is requesting a return on long-term debt of 3.70%, based on its actual long-term debt rates. HCHI is currently paying rates that vary between 2.90% and 4.40% on debentures with Infrastructure Ontario, on account of funding for the implementation of Smart Meters, Customer Information System ("CIS") conversion project, and annual capital construction projects.

In late 2013, HCHI expects to apply for and receive additional short-term construction financing from Infrastructure Ontario to be converted into long-term debenture financing in late 2014 to meet anticipated cash requirements for capital construction projects. At this time the interest rate is not known. For purposes of this Application, HCHI has calculated the interest cost for the short-term financing at a rate of 1.80% and when

converted to long-term at a rate of 3.82%. Both of these rates, 1.80% and 3.82% were obtained from the Infrastructure Ontario website with effective dates of January 15, 2013.

Long-term debt cost information for the 2010, 2011, and 2012 Actuals, and 2013 Bridge Year and 2014 Test Year are included in Tab 1, Schedule 3, and Table 2 of this Exhibit.

Short-Term Debt

For the 2014 Test Year, HCHI is requesting a return on short-term debt of 2.07%, consistent with the *Cost of Capital Parameter Updates for 2013 Cost of Service Applications* issued by the Board on February 14, 2013. HCHI understands that the Board will be finalizing the return on short-term debt in early 2014 for rates effective May 1, 2014. HCHI's use of a return on short-term debt of 2.07% as a proxy in this Application is without prejudice to any revisions that may be adopted by the Board in early 2014.

Return on Equity

For the 2014 Test Year, HCHI is requesting a return on equity ("ROE") of 8.98% consistent with the *Cost of Capital Parameter Updates for 2013 Cost of Service Applications* issued by the Board on February 14, 2013. HCHI understands that the Board will update the return on equity rate in early 2014 for rates effective May 1, 2014. HCHI's use of a ROE of 8.98% as a proxy in this Application is without prejudice to any revised ROE that may be adopted by the Board in early 2014.

Capital Structure

As discussed in the overview of this Exhibit, HCHI has a deemed capital structure of 60% debt – 56% long-term and 4% short-term - and 40% equity for rate-making purposes as determined in the *"Report of the Board on the Cost of Capital for Ontario's Regulated Utilities"* (EB-2009-0084) ("Cost of Capital Report") noting "…*that a split of 60% debt, 40% equity is appropriate for all distributors*".

HCHI has prepared Table 1 to illustrate its capital structure and component costs, in accordance with the Board's *Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications*, updated July 17, 2013 (the "Filing Requirements"), for the following years:

- 2010 Board Approved;
- 2010 Actual;
- 2011 Actual;
- 2012 Actual;
- 2013 Bridge Year; and
- 2014 Test Year.

Cost of Debt and Return on Equity calculations for the 2014 Test Year are discussed in the corresponding Schedules and Tables below.

Table 1
Capitalization and Cost of Capital

Deemed Capital Structure for 2010 Board Approved

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	22,520,520	56.00%	5.13%	1,155,303
Short Term Debt	1,608,609	4.00%	2.07%	33,298
Total Debt	24,129,128	60.00%		1,188,601
Common Share Equity	16,086,086	40.00%	9.85%	1,584,479
Total equity	16,086,086	40.00%		1,584,479
Total Rate Base	40,215,214	100.00%	6.90%	2,773,080

Deemed Capital Structure for 2010

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	23,063,287	56.00%	5.13%	1,183,147
Short Term Debt	1,647,378	4.00%	2.07%	34,101
Total Debt	24,710,665	60.00%		1,217,247
Common Share Equity	16,473,777	40.00%	9.85%	1,622,667
Total equity	16,473,777	40.00%		1,622,667
Total Rate Base	41,184,442	100.00%	6.90%	2,839,914

Deemed Capital Structure for 2011

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	24,011,692	56.00%	5.13%	1,231,800
Short Term Debt	1,715,121	4.00%	2.07%	35,503
Total Debt	25,726,813	60.00%		1,267,303
Common Share Equity	17,151,209	40.00%	9.85%	1,689,394
Total equity	17,151,209	40.00%		1,689,394
Total Rate Base	42,878,022	100.00%	6.90%	2,956,697

Deemed Capital Structure for 2012

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	26,061,342	56.00%	5.13%	1,336,947
Short Term Debt	1,861,524	4.00%	2.07%	38,534
Total Debt	27,922,867	60.00%		1,375,480
Common Share Equity	18,615,245	40.00%	9.85%	1,833,602
Total equity	18,615,245	40.00%		1,833,602
Total Rate Base	46,538,112	100.00%	6.90%	3,209,082

Deemed Capital Structure for 2013 Bridge

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	28,730,444	56.00%	5.13%	1,473,872
Short Term Debt	2,052,175	4.00%	2.07%	42,480
Total Debt	30,782,618	60.00%		1,516,352
Common Share Equity	20,521,745	40.00%	9.85%	2,021,392
Total equity	20,521,745	40.00%		2,021,392
Total Rate Base	51,304,364	100.00%	6.90%	3,537,744

Deemed Capital Structure for 2014 Test

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	30,126,659	56.00%	3.70%	1,114,686
Short Term Debt	2,151,904	4.00%	2.07%	44,544
Total Debt	32,278,563	60.00%		1,159,231
Common Share Equity	21,519,042	40.00%	8.98%	1,932,410
Total equity	21,519,042	40.00%		1,932,410
Total Rate Base	53,797,605	100.00%	5.75%	3,091,641

The information contained in Table 1 can also be found in Appendix 2-OA "Capital Structure".

COST OF DEBT

Long-Term Debt

In its Cost of Capital Report, the Board established policies with respect to long-term debt. All of HCHI's long-term debt is third party debt, with a component of embedded debt and a component of new debt. The Board's report established embedded debt as "*long-term debt at rates that differ according to when the debt was incurred*". (Debt incurred at time when assets put in-service and the cost of the debt is at prevailing market rates.) Details of new debt in 2013 and 2014 have been discussed in the Overview section of this Exhibit at Tab 1, Schedule 1.

The Board determined that for embedded debt, the rate approved in prior Board decisions shall be maintained for the life of each active instrument, unless a new rate is negotiated, in which case it will be treated as new debt. For new third party debt, the Board determined the rate will be a prudently negotiated contracted rate and would include recognition of premiums and discounts.

Table 2 below provides details of the long-term debt held by third parties in each of the 2010, 2011, and 2012 Actuals, 2013 Bridge Year, and the 2014 Test Year and the weighted cost of each year's debt. This same information is in Appendix 2-OB "Debt Instruments".

Short-Term Debt

As discussed in the Overview section of this Exhibit, HCHI has used a short-term debt rate for the 2014 Test year of 2.07%. In the Cost of Capital Report the Board confirmed its determination that "*short-term debt should be factored into rate setting, and that a deemed amount should be included in the capital structures of electricity distributors*". The short-term debt amount will be fixed at 4% of rate base. In the 2014 Test Year in Table 1 above, it can be noted that HCHI has used a short-term debt rate of 2.07%

calculated on 4% of rate base. HCHI understands that the Board will update the short-term debt rate in early 2014 for rates effective May 1, 2014.

Table 2
Long-Term Debt Details and Weighted Cost

		Year	2010					
Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%)	Interest ($)
Term Loan	CIBC	Third-Party	Variable Rate	21-Dec-01	10	$ 300,000	4.52%	$ 13,560.00
Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	1-Apr-10	5	$ 699,619	2.92%	$ 20,428.87
Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	1-Apr-10	10	$ 3,900,168	3.90%	$ 152,106.55
Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	1-Apr-10	15	$ 2,966,667	4.39%	$ 130,236.68
Total						$ 7,866,454	4.02%	$ 316,332.11

		Year	2011					
Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%)	Interest ($)
Term Loan	CIBC	Third-Party	Variable Rate	21-Dec-01	10	$ 100,000	2.98%	$ 2,980.00
Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	1-Apr-10	5	$ 771,994	2.94%	$ 22,696.62
Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	1-Apr-10	10	$ 4,759,528	3.92%	$ 186,573.50
Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	1-Apr-10	15	$ 3,733,333	4.41%	$ 164,639.99
Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	15-Aug-11	monthly	$ 2,638,113	0.80%	$ 21,104.90
Total						$ 12,002,968	3.32%	$ 397,995.01

		Year	2012					
Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%)	Interest ($)
Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	1-Apr-10	5	$ 578,995	2.91%	$ 16,848.75
Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	1-Apr-10	10	$ 4,230,691	3.89%	$ 164,573.88
Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	1-Apr-10	15	$ 3,466,667	4.38%	$ 151,840.01
Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	15-Aug-11	monthly	$ 3,165,735	1.26%	$ 39,888.26
Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	17-Sep-12	25	$ 1,506,516	3.76%	$ 56,645.00
Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	17-Sep-12	10	$ 175,145	2.90%	$ 5,079.21
Total						$ 13,123,749	3.31%	$ 434,875.12

		Year	2013					
Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%)	Interest ($)
Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	1-Apr-10	5	$ 385,997	2.92%	$ 11,271.11
Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	1-Apr-10	10	$ 3,701,855	3.90%	$ 144,372.35
Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	1-Apr-10	15	$ 3,200,000	4.39%	$ 140,480.00
Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	17-Sep-12	25	$ 5,905,544	3.76%	$ 222,048.45
Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	17-Sep-12	10	$ 665,550	2.91%	$ 19,367.51
Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	1-Oct-13	Monthly	$ 375,000	1.79%	$ 6,712.50
Total						$ 14,233,946	3.82%	$ 544,251.92

		Year	2014					
Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%)	Interest ($)
Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	1-Apr-10	5	$ 192,998	2.92%	$ 5,635.54
Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	1-Apr-10	10	$ 3,173,018	3.90%	$ 123,747.70
Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	1-Apr-10	15	$ 2,933,333	4.39%	$ 128,773.32
Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	17-Sep-12	25	$ 5,664,501	3.76%	$ 212,985.24
Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	17-Sep-12	10	$ 595,492	2.88%	$ 17,150.17
Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	1-Oct-13	Monthly	$ 1,312,500	1.80%	$ 23,625.00
Debenture - OILC	Infrastructure Ontario	Third-Party	Fixed Rate	15-Oct-14	25	$ 625,000	3.81%	$ 23,812.50
Total						$ 14,496,842	3.70%	$ 535,729.47

RETURN ON EQUITY

As indicated in the Overview section of this Exhibit, HCHI is requesting a ROE for the 2014 Test Year of 8.98%. HCHI understands that the Board will update the return on equity rate in early 2014 for rates effective May 1, 2014.

Exhibit 6 – Calculation of Revenue Deficiency

	Tab	Schedule	Appendix
Overview of Revenue Deficiency	1	1	
Cost Drivers for Revenue Deficiency		2	
Revenue Requirement Work Form			A

OVERVIEW OF REVENUE DEFICIENCY

The information in this Exhibit supports Haldimand County Hydro Inc.'s ("HCHI's") request in this Application for an increase in its Revenue Requirement. HCHI's net revenue deficiency is $21,803 and when grossed up for Payments in Lieu of Taxes ("PILs") is $27,264. This deficiency is calculated as the difference between the 2014 Test Year Revenue Requirement of $14,012,613 and the Forecast 2014 Test Year Revenue based on the current 2013 approved rates of $13,985,349.

HCHI's revenue requirement consists of the following:

- Administrative & General, Billing & Collecting Expenses;
- Operating & Maintenance Expenses
- Depreciation Expense
- Property Taxes
- PILs
- Deemed Interest & Return on Equity

HCHI has provided detailed calculations supporting its 2014 revenue deficiency, net of electricity price differentials and of any costs associated with Low Voltage charges, as required in the Board's Filing Requirements. As indicated in Exhibit 5, Tab 1, Schedules 1 and 4, HCHI is requesting a 2014 Test Year rate of return of 8.98% on 40% of the requested rate base of $53,797,605 (see Exhibit 2, Tab 1, Schedule 1 for detailed calculations). HCHI would only earn a rate of return of 8.88% if revenues remained at the 2013 Board Approved rates calculated on the 2014 forecasted load, thus generating the revenue deficiency.

Table 1 on the following page provides the "Calculation of Revenue Deficiency" for the 2014 Test Year at existing 2013 Board Approved rates and the 2014 Test Year Revenue Requirement of $14,012,613. This information is a direct insertion of worksheet 8 "Revenue Deficiency/Sufficiency" from the OEB's required "Revenue Requirement Work Form" model filed as Appendix A to this Exhibit.

Table 1
Calculation of Revenue Deficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates
1	Revenue Deficiency from Below		$27,264
2	Distribution Revenue	$12,847,288	$12,847,288
3	Other Operating Revenue Offsets - net	$1,138,061	$1,138,061
4	**Total Revenue**	$13,985,349	$14,012,613
5	Operating Expenses	$10,820,480	$10,820,480
6	Deemed Interest Expense	$1,159,231	$1,159,231
8	**Total Cost and Expenses**	$11,979,711	$11,979,711
9	**Utility Income Before Income Taxes**	$2,005,638	$2,032,902
10	Tax Adjustments to Accounting Income per 2013 PILs model	($1,391,417)	($1,391,417)
11	**Taxable Income**	$614,221	$641,485
12	Income Tax Rate	20.03%	20.03%
13	**Income Tax on Taxable Income**	$123,031	$128,492
14	**Income Tax Credits**	($28,000)	($28,000)
15	**Utility Net Income**	$1,910,607	$1,932,410
16	**Utility Rate Base**	$53,797,605	$53,797,605
17	Deemed Equity Portion of Rate Base	$21,519,042	$21,519,042
18	Income/(Equity Portion of Rate Base)	8.88%	8.98%
19	Target Return - Equity on Rate Base	8.98%	8.98%
20	Deficiency/Sufficiency in Return on Equity	-0.10%	0.00%
21	Indicated Rate of Return	5.71%	5.75%
22	Requested Rate of Return on Rate Base	5.75%	5.75%
23	Deficiency/Sufficiency in Rate of Return	-0.04%	0.00%
24	Target Return on Equity	$1,932,410	$1,932,410
25	Revenue Deficiency/(Sufficiency)	$21,803	$0
26	**Gross Revenue Deficiency/(Sufficiency)**	$27,264 **(1)**	

COST DRIVERS FOR REVENUE DEFICIENCY

HCHI notes there are several factors contributing to the gross revenue deficiency of $27,264 for the 2014 Test Year. The following discussion highlights some significant items that contribute to this deficiency.

Operating Expenses

Although operating expenses have increased from the last rebasing year's actuals of 2010 through to the 2014 Test Year, other components of the Revenue Requirement have decreased, such as depreciation and the deemed interest expense, which is producing a minimal revenue deficiency for HCHI. Operating expenses have increased $1,831,969, or 24.7% from the 2010 Actual of $6,874,523 to the 2014 Test Year of $8,706,492. This is a compound annual growth rate for all years of 4.8% as detailed in Appendix 2-JA "OM&A Summary Analysis". The addition of the Smart Meter costs in 2012 as a result of HCHI's approved disposition in its Smart Meter Cost Recovery application (EB-2012-0272) has contributed to this increase. Additional cost drivers for the increase in operating expenses over the 4 year period are discussed in detail in Exhibit 4, Tab 1, Schedule 2. The offset to this increase is the decrease in depreciation expense related to the property, plant and equipment ("PPE") adjustment completed for the change in estimated useful lives. Table 2 below shows the net effect of this accounting change on the 2014 Test Year including the return on rate base, depreciation, and the PILs for a total decrease of $1,788,691. This is also detailed in Appendix 2-YB "CGAAP Summary Impacts" filed as part of this Application. Another decrease can be attributed to the lower weighted average debt rate of 3.59% calculated for the 2014 Test Year as compared to 4.93% approved with the 2010 COS rate application (EB-2009-0265) resulting in a lower deemed interest expense.

Table 2
Summary of Impacts to Revenue Requirement
From Accounting Changes under CGAAP

Revenue Requirement Component	2014 CGAAP or ASPE with the changes to the policies	2014 CGAAP without the changes to the policies	Difference	Reasons why the revenue requirement component is different under CGAAP or ASPE with the changes to the policies versus CGAAP without the changes to the policies
Closing NBV 2013	$ 44,754,221	$ 43,295,036	$ 1,459,185	PPE Adjustment booked to a/c 1576 - change in useful lives
Closing NBV 2014	$ 48,615,181	$ 45,724,474	$ 2,890,707	Change in useful lives completed January 1, 2013
Average NBV	$ 46,684,701	$ 44,509,755	$ 2,174,946	
Working Capital	$ 7,112,904	$ 7,112,904	$ -	
Rate Base	$ 53,797,605	$ 51,622,659	$ 2,174,946	
Return on Rate Base	$ 3,091,641	$ 2,966,651	$ 124,990	Change in useful lives
			$ -	
OM&A	$ 8,706,492	$ 8,706,492	$ -	
Depreciation	$ 2,113,988	$ 3,545,511	$ (1,431,523)	Change in useful lives
PILs or Income Taxes	$ 100,492	$ 582,650	$ (482,158)	Tax affect on above
			$ -	
Less: Revenue Offsets	$ (1,138,061)	$ (1,138,061)	$ -	
			$ -	
Total Base Revenue Requirement	$ 12,874,552	$ 14,663,243	$ (1,788,691)	

Rate Base

HCHI's rate base has significantly increased in the 2014 Test Year at $53,797,605 from its 2010 Board Approved COS rate application of $40,215,214. The majority of this increase is on account of the addition of the Smart Meter capital to rate base upon Board Approval in 2012 and an increased annual capital spend commencing in the 2011 Actual through to the 2014 Test Year of approximately $1,500,000. The accounting change under Canadian Generally Accepted Accounting Principles ("CGAAP") in asset useful lives also caused an increase in rate base as shown in Table 2 above. Even though the working capital allowance has decreased from 15% to 13%, the cost of power has increased mainly due to an overall increase in rates. The changes to rate base for the accounting change under CGAAP, the working capital and the annual capital spend have been discussed in detail in Exhibit 2 of this Application. The regulated rate of return has also decreased from the 2010 Board Approved amount of 6.90% to the 2014 Test Year amount of 5.75%.

Summary

Overall, the small revenue deficiency is a result of the increases in operating expenses and rate base offset by the reduced regulated rate of return and the effects of the accounting change in useful lives on depreciation, rate base, and PILs.



Revenue Requirement Workform

Version 4.00

Utility Name	Haldimand County Hydro Inc.
Service Territory	*Haldimand County*
Assigned EB Number	EB-2013-0134
Name and Title	Jacqueline A. Scott
Phone Number	905-765-5211 ext.2237
Email Address	jscott@hchydro.ca

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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



1. Info
2. Table of Contents
3. Data_Input_Sheet
4. Rate_Base
5. Utility Income
6. Taxes_PILs
7. Cost_of_Capital
8. Rev_Def_Suff
9. Rev_Reqt

Notes:

(1)	Pale green cells represent inputs
(2)	Pale green boxes at the bottom of each page are for additional notes
(3)	Pale yellow cells represent drop-down lists
(4)	***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5)	***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel***



Data Input (1)

		Initial Application	(2)		(6)		Per Board Decision	
1	**Rate Base**							
	Gross Fixed Assets (average)	$78,029,080		$ 78,029,080			$78,029,080	
	Accumulated Depreciation (average)	($31,344,380)	(5)	($31,344,380)			($31,344,380)	
	Allowance for Working Capital:							
	Controllable Expenses	$8,706,491		$ 8,706,491			$8,706,491	
	Cost of Power	$46,008,158		$ 46,008,158			$46,008,158	
	Working Capital Rate (%)	13.00%	(9)	13.00%	(9)		13.00%	(9)
2	**Utility Income**							
	Operating Revenues:							
	Distribution Revenue at Current Rates	$12,847,288						
	Distribution Revenue at Proposed Rates	$12,874,551						
	Other Revenue:							
	Specific Service Charges	$27,730						
	Late Payment Charges	$310,717						
	Other Distribution Revenue	$144,374						
	Other Income and Deductions	$655,240						
	Total Revenue Offsets	$1,138,061	(7)					
	Operating Expenses:							
	OM+A Expenses	$8,658,381		$ 8,658,381			$8,658,381	
	Depreciation/Amortization	$2,113,988		$ 2,113,988			$2,113,988	
	Property taxes	$48,110		$ 48,110			$48,110	
	Other expenses							
3	**Taxes/PILs**							
	Taxable Income:							
	Adjustments required to arrive at taxable income	($1,391,417)	(3)					
	Utility Income Taxes and Rates:							
	Income taxes (not grossed up)	$80,363						
	Income taxes (grossed up)	$100,492						
	Federal tax (%)	15.00%						
	Provincial tax (%)	5.03%						
	Income Tax Credits	($28,000)						
4	**Capitalization/Cost of Capital**							
	Capital Structure:							
	Long-term debt Capitalization Ratio (%)	56.0%						
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		(8)			(8)
	Common Equity Capitalization Ratio (%)	40.0%						
	Prefered Shares Capitalization Ratio (%)							
		100.0%						
	Cost of Capital							
	Long-term debt Cost Rate (%)	3.70%						
	Short-term debt Cost Rate (%)	2.07%						
	Common Equity Cost Rate (%)	8.98%						
	Prefered Shares Cost Rate (%)							

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.



Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application						Per Board Decision
1	Gross Fixed Assets (average)	(3)	$78,029,080		$ -		$78,029,080	$ -	$78,029,080
2	Accumulated Depreciation (average)	(3)	($31,344,380)		$ -		($31,344,380)	$ -	($31,344,380)
3	Net Fixed Assets (average)	(3)	$46,684,700		$ -		$46,684,700	$ -	$46,684,700
4	Allowance for Working Capital	(1)	$7,112,904		$ -		$7,112,904	$ -	$7,112,904
5	**Total Rate Base**		$53,797,604		$ -		$53,797,604	$ -	$53,797,604

(1) Allowance for Working Capital - Derivation

6	Controllable Expenses		$8,706,491		$ -		$8,706,491	$ -	$8,706,491
7	Cost of Power		$46,008,158		$ -		$46,008,158	$ -	$46,008,158
8	Working Capital Base		$54,714,649		$ -		$54,714,649	$ -	$54,714,649
9	Working Capital Rate %	(2)	13.00%		0.00%		13.00%	0.00%	13.00%
10	Working Capital Allowance		$7,112,904		$ -		$7,112,904	$ -	$7,112,904

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2014 cost of service applications is 13%.

(3) Average of opening and closing balances for the year.



Utility Income

Line No.	Particulars		Initial Application					Per Board Decision
	Operating Revenues:							
1	Distribution Revenue (at Proposed Rates)		$12,874,551	($12,874,551)	$ -	$ -		$ -
2	Other Revenue	(1)	$1,138,061	($1,138,061)	$ -	$ -		$ -
3	Total Operating Revenues		$14,012,612	($14,012,612)	$ -	$ -		$ -
	Operating Expenses:							
4	OM+A Expenses		$8,658,381	$ -	$8,658,381	$ -		$8,658,381
5	Depreciation/Amortization		$2,113,988	$ -	$2,113,988	$ -		$2,113,988
6	Property taxes		$48,110	$ -	$48,110	$ -		$48,110
7	Capital taxes		$ -	$ -	$ -	$ -		$ -
8	Other expense		$ -	$ -		$ -		
9	Subtotal (lines 4 to 8)		$10,820,479	$ -	$10,820,479	$ -		$10,820,479
10	Deemed Interest Expense		$1,159,231	($1,159,231)	$ -	$ -		$ -
11	Total Expenses (lines 9 to 10)		$11,979,710	($1,159,231)	$10,820,479	$ -		$10,820,479
12	**Utility income before income taxes**		$2,032,902	($12,853,381)	($10,820,479)	$ -		($10,820,479)
13	Income taxes (grossed-up)		$100,492	$ -	$100,492	$ -		$100,492
14	**Utility net income**		$1,932,410	($12,853,381)	($10,920,971)	$ -		($10,920,971)

Notes

Other Revenues / Revenue Offsets

(1)	Specific Service Charges	$27,730		$ -	$ -
	Late Payment Charges	$310,717		$ -	$ -
	Other Distribution Revenue	$144,374		$ -	$ -
	Other Income and Deductions	$655,240		$ -	$ -
	Total Revenue Offsets	$1,138,061	$ -	$ -	$ -	$ -



Taxes/PILs

Line No.	Particulars	Application				Per Board Decision	
	Determination of Taxable Income						
1	Utility net income before taxes	$1,932,410		$ -		$ -	
2	Adjustments required to arrive at taxable utility income	($1,391,417)	(1)	$ -		($1,391,417)	
3	Taxable income	$540,993		$ -		($1,391,417)	
	Calculation of Utility income Taxes						
4	Income taxes	$80,363	(2)	$80,363		$80,363	
6	Total taxes	$80,363		$80,363		$80,363	
7	Gross-up of Income Taxes	$20,129		$20,129		$20,129	
8	Grossed-up Income Taxes	$100,492		$100,492		$100,492	
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$100,492		$100,492		$100,492	
10	Other tax Credits	($28,000)	(3)	($28,000)		($28,000)	
	Tax Rates						
11	Federal tax (%)	15.00%		15.00%		15.00%	
12	Provincial tax (%)	5.03%		5.03%		5.03%	
13	Total tax rate (%)	20.03%		20.03%		20.03%	

Notes

1	ATTC - Adjustments include 2 apprentices at $10,000 maximum each for a total of $20,000; plus CETC - 2 co-op students for a maximum of $3,000 each for a total of $6,000; plus ITC - adjustment for apprenticeship job creation of $2,000 maximum.
2	Income taxes not grossed-up include deduction for other tax credits detailed in note 1.
3	Other tax credits detailed in note 1.



Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate		Return
		Initial Application				
		(%)	($)	(%)		($)
	Debt					
1	Long-term Debt	56.00%	$30,126,658	3.70%		$1,114,686
2	Short-term Debt	4.00%	$2,151,904	2.07%		$44,544
3	**Total Debt**	60.00%	$32,278,563	3.59%		$1,159,231
	Equity					
4	Common Equity	40.00%	$21,519,042	8.98%		$1,932,410
5	Preferred Shares	0.00%	$ -	0.00%		$ -
6	**Total Equity**	40.00%	$21,519,042	8.98%		$1,932,410
7	**Total**	100.00%	$53,797,604	5.75%		$3,091,641
		(%)	($)	(%)		($)
	Debt					
1	Long-term Debt	0.00%	$ -	0.00%		$ -
2	Short-term Debt	0.00%	$ -	0.00%		$ -
3	**Total Debt**	0.00%	$ -	0.00%		$ -
	Equity					
4	Common Equity	0.00%	$ -	0.00%		$ -
5	Preferred Shares	0.00%	$ -	0.00%		$ -
6	**Total Equity**	0.00%	$ -	0.00%		$ -
7	**Total**	0.00%	$53,797,604	0.00%		$ -
		Per Board Decision				
		(%)	($)	(%)		($)
	Debt					
8	Long-term Debt	0.00%	$ -	3.70%		$ -
9	Short-term Debt	0.00%	$ -	2.07%		$ -
10	**Total Debt**	0.00%	$ -	0.00%		$ -
	Equity					
11	Common Equity	0.00%	$ -	8.98%		$ -
12	Preferred Shares	0.00%	$ -	0.00%		$ -
13	**Total Equity**	0.00%	$ -	0.00%		$ -
14	**Total**	0.00%	$53,797,604	0.00%		$ -

Notes

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I



Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application				Per Board Decision	
		At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$27,263		($2,410,338)		$10,820,479
2	Distribution Revenue	$12,847,288	$12,847,288	$12,847,288	$15,284,889	$ -	($10,820,479)
3	Other Operating Revenue Offsets - net	$1,138,061	$1,138,061	$ -	$ -	$ -	$ -
4	**Total Revenue**	$13,985,349	$14,012,612	$12,847,288	$12,874,551	$ -	$ -
5	Operating Expenses	$10,820,479	$10,820,479	$10,820,479	$10,820,479	$10,820,479	$10,820,479
6	Deemed Interest Expense	$1,159,231	$1,159,231	$ -	$ -	$ -	$ -
8	**Total Cost and Expenses**	$11,979,710	$11,979,710	$10,820,479	$10,820,479	$10,820,479	$10,820,479
9	**Utility Income Before Income Taxes**	$2,005,639	$2,032,902	$2,026,809	$2,054,072	($10,820,479)	($10,820,479)
10	Tax Adjustments to Accounting Income per 2013 PILs model	($1,391,417)	($1,391,417)	($1,391,417)	($1,391,417)	$ -	$ -
11	**Taxable Income**	$614,222	$641,485	$635,392	$662,655	($10,820,479)	($10,820,479)
12	Income Tax Rate	20.03%	20.03%	20.03%	20.03%	20.03%	20.03%
13	**Income Tax on Taxable Income**	$123,031	$128,492	$127,272	$132,732	($2,167,385)	($2,167,385)
14	**Income Tax Credits**	($28,000)	($28,000)	($28,000)	($28,000)	$ -	$ -
15	**Utility Net Income**	$1,910,608	$1,932,410	$1,927,537	($10,920,971)	($8,653,094)	($10,920,971)
16	**Utility Rate Base**	$53,797,604	$53,797,604	$53,797,604	$53,797,604	$53,797,604	$53,797,604
17	Deemed Equity Portion of Rate Base	$21,519,042	$21,519,042	$ -	$ -	$ -	$ -
18	Income/(Equity Portion of Rate Base)	8.88%	8.98%	0.00%	0.00%	0.00%	0.00%
19	Target Return - Equity on Rate Base	8.98%	8.98%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Return on Equity	-0.10%	0.00%	0.00%	0.00%	0.00%	0.00%
21	Indicated Rate of Return	5.71%	5.75%	3.58%	0.00%	-16.08%	0.00%
22	Requested Rate of Return on Rate Base	5.75%	5.75%	0.00%	0.00%	0.00%	0.00%
23	Deficiency/Sufficiency in Rate of Return	-0.04%	0.00%	3.58%	0.00%	-16.08%	0.00%
24	Target Return on Equity	$1,932,410	$1,932,410	$ -	$ -	$ -	$ -
25	Revenue Deficiency/(Sufficiency)	$21,802	$0	($1,927,537)	$ -	$8,653,094	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$27,263 **(1)**		($2,410,338) **(1)**		$10,820,479 **(1)**	

Notes:
(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)



Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$8,658,381		$8,658,381		$8,658,381	
2	Amortization/Depreciation	$2,113,988		$2,113,988		$2,113,988	
3	Property Taxes	$48,110		$48,110		$48,110	
5	Income Taxes (Grossed up)	$100,492		$100,492		$100,492	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$1,159,231		$ -		$ -	
	Return on Deemed Equity	$1,932,410		$ -		$ -	
8	**Service Revenue Requirement (before Revenues)**	$14,012,612		$10,920,971		$10,920,971	
9	Revenue Offsets	$1,138,061		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$12,874,551		$10,920,971		$10,920,971	
11	Distribution revenue	$12,874,551		$ -		$ -	
12	Other revenue	$1,138,061		$ -		$ -	
13	**Total revenue**	$14,012,612		$ -		$ -	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$0	(1)	($10,920,971)	(1)	($10,920,971)	(1)

Notes
(1) Line 11 - Line 8

Exhibit 7 – Cost Allocation

	Tab	Schedule	Appendix
Cost Allocation Overview	1	1	
Weighting Factors		2	
2014 Cost Allocation Updates		3	
Summary of Results and Proposed Changes		4	
2014 Cost Allocation Model Input Sheets I-6 and I-8			A
2014 Cost Allocation Model Output Sheets O-1 and O-2			B

COST ALLOCATION – OVERVIEW

On September 29, 2006, the Board issued its *Directions on Cost Allocation Methodology for Electricity Distributors* (the "Directions"). On November 15, 2006, the Board issued the *Cost Allocation Information Filing Guidelines for Electricity Distributors* ("the Guidelines"), the Cost Allocation Model (the "Model") and User Instructions (the "Instructions") for the Model. Haldimand County Hydro Inc. ("HCHI") prepared a cost allocation information filing consistent with HCHI's understanding of the Directions, the Guidelines, the Model and the Instructions.

One of the main objectives of the filing was to provide information on any apparent cross-subsidization among a distributor's rate classifications. The cost allocation study focused on distribution costs and whether or not the utility's distribution rates by customer class were collecting the cost of providing distribution service to that corresponding customer rate class. It was felt that this would give an indication of cross-subsidization from one customer class to another and that this information would be useful as a tool in future rate applications.

In HCHI's 2010 COS rate application (EB-2009-0265), the results of the original cost allocation study filed on February 28, 2007 were used as a basis for HCHI to propose reallocations of distribution costs across customer rate classes to address the issue of cross-subsidization. The reallocations were based on the objective of moving the revenue-to-cost ratios to be within the Board's acceptable range as outlined in the "*Report on Application of Cost Allocation for Electricity Distributors*" (the Cost Allocation Report") issued by the Board on November 28, 2007. At that time, two of HCHI's customer rate classes were outside of the acceptable ranges, including Street Lighting and Sentinel Lighting. HCHI was approved to move the Street Lighting and Sentinel Lighting rate classes to the minimum of the target range by 2011 in equal increments. The benefactor of these two classes' moves was the General Service 50 to 4,999 kW customer rate class which was within their acceptable range but over contributing by

36.4%. The additional revenue from the Street Lighting and Sentinel Lighting rate classes was used each year to reduce the General Service 50 to 4,999 kW rates.

On September 2, 2010, the Board began a proceeding, EB-2010-0219, with the mandate to review and revise the existing Cost Allocation policy as needed. On March 31, 2011, the Report of the Board was released in relation to EB-2010-0219. In the letter accompanying the report, the Board indicated that a Working Group would be formed to revise the original Cost Allocation Model to address the revision highlighted in the March 31st Board Report. On August 5, 2011, the Board released its new Cost Allocation Model and instructed 2012 Cost of Service filers to use the revised model in their applications and on June 28, 2012, the Board again released a revised Cost Allocation Model to be used by 2013 Cost of Service filers in their applications. For 2014 Cost of Service filers, the Board released a revised Cost Allocation Model ("the Model") on August 2, 2013 to be used in 2014 applications.

In section 2.6.4 of the March 31st Board Report, the Board stated that "*default weighting factors should now be utilized only in exceptional circumstances*". Distributors are now expected to develop their own weighting factors.

For purposes of this Application, HCHI has completed an updated cost allocation study using the Board's methodology and revised Model issued on August 2, 2013. HCHI's cost allocation study reflects the 2014 Test Year costs and asset information, 2014 forecasted load information by rate class, 2014 forecasted customer and meter information, and the 2014 demand values based on the weather normalized load forecast used to design rates. HCHI has developed its own weighting factors as outlined below based on discussions with staff experienced in the subject area. Tables 1 and 2 that follow present HCHI's own weighting factors and include the original Board default weighting factors. Further details of information used in the updated 2014 Cost Allocation Model are provided in this Exhibit at Tab 1, Schedule 3.

HCHI has included the updated Model to reflect 2014 Test Year information in Excel format as part of this Application as a requirement in the Board's Filing Requirements issued July 17, 2013.

WEIGHTING FACTORS

Services (Account 1855)

The installation of a typical Residential service requires no capital contribution from the customer whereas all other rate classes are required to contribute a portion of the actual cost, depending upon the type of installation, in accordance with HCHI's Conditions of Service.

As per the suggested methodology on the Cost Allocation Model instruction sheet, the Residential class was given a weighting factor of 1. Costs were analyzed for each different type of installation that HCHI experiences for a Residential customer. These costs were then multiplied by the estimated number of Residential customers for each type of service to come up with an average weighted service cost for a Residential customer. This cost was assigned a factor of 1. The same methodology was applied to each of HCHI's customer rate classes to come up with an average weighted service cost for each. This cost was then weighted to the Residential rate class cost to calculate the weighting factor for each customer rate class. Table 1 details these weighting factors.

Table 1
Services (1855) Weighting Factors

Customer Class	HCHI Services Weighting Factors
Residential	1.00
General Service Less Than 50 kW	1.05
General Service 50 to 4,999 kW	1.24
Street Lighting	0.82
Sentinel Lighting	0.82
Unmetered Scattered Load	0.82
Embedded Distributor - Hydro One Networks Inc.	1.60

Billing and Collecting (Accounts 5315 – 5340, except 5335)

In determining the weighting factors for billing and collecting, a detailed analysis was completed of the costs booked to accounts 5315 through to and including 5340, except for account 5335. Different allocation methods were used to record costs to each of the customer rate classes depending upon the type of cost. Some costs were allocated based on number of bills issued in each class, some were allocated based on number of enrolled customers within each class, some were allocated based on number of customers involved in active collections, and other costs were allocated based on type of commodity pricing charged within the customer class.

With respect to assigning weighting factors to the Billing and Collecting costs, the same methodology used for Services was applied. The Residential class was given a weighting factor of 1 as suggested in the Cost Allocation Model instruction sheet. Total costs for the Residential class were divided by the number of bills issued in a year for that class to derive an average weighted billing and collecting cost for a Residential customer. This cost was assigned a factor of 1. The same methodology was applied to each of HCHI's customer rate classes to derive an average weighted billing and collecting cost for each. This cost was then weighted to the Residential rate class cost to calculate the weighting factor for each class. Table 2 details these weighting factors.

Table 2
Billing and Collecting (5315 – 5340, except 5335) Weighting Factors

Customer Class	HCHI Billing & Collecting Weighting Factors
Residential	1.00
General Service Less Than 50 kW	1.05
General Service 50 to 4,999 kW	1.06
Street Lighting	2.96
Sentinel Lighting	1.08
Unmetered Scattered Load	1.03
Embedded Distributor - Hydro One Networks Inc.	0.70

Meter Capital

For meter capital, a weighting factor is assigned to each customer rate class calculated directly in the Model on worksheet "I7.1 Meter Capital". HCHI has input into the Model on worksheet I7.1 the installation cost per meter type within each customer rate class and number of customers with each type of meter. Costs represent current replacement costs for each meter type including an estimated labour and truck component for installation. All meter types for Residential, General Service Less Than 50 kW, and the General Service 50 to 4,999 kW (non-interval metered) customers are various types of Smart Meters installed in HCHI's territory. Table 3 details the installed costs of meter capital by type of meter.

Table 3
Installed Costs of Meter Capital

Meter Type	Installation Cost per Meter	
Single Phase 200 Amp	$	240.29
Single Phase 200 Amp Bi-Directional	$	163.03
Single Phase Central Meter - No Demand	$	458.95
120V 10 Amp PMU - No Demand	$	12,044.70
Network Meter - No Demand	$	309.02
Three-phase 200 Amp-No Demand	$	685.05
Three-phase with IT's 10 Amp - No Demand / With Demand	$	3,012.27
Three Phase 10 Amp PMU - No Demand	$	32,257.82
Single Phase Central Meter-Demand	$	931.89
120V 10 Amp PMU-Demand	$	12,130.39
Three-phase 200 Amp - Demand	$	688.79
Three Phase 10 Amp PMU - Demand	$	32,352.14
Interval 120-347V 10 Amp	$	3,496.15
Interval 120-347V 10 Amp PMU	$	32,836.01
HONI Single Phase 10 Amp PMU	$	12,834.46
HONI Three Phase 10 Amp PMU	$	32,931.13
Single Phase 10 Amp Bi-Directional	$	2,633.40
Three Phase 10 Amp Bi-Directional	$	14,515.38
Three Phase 10 Amp Bi-Directional	$	3,591.27
Three Phase 200 Amp Bi-Directional	$	1,428.53

Meter Reading

For meter reading, a weighting factor is assigned to each customer rate class calculated directly in the Model on worksheet "I7.2 Meter Reading". HCHI has input into the Model the number of customers by meter reading type within each rate class. The weighting factor assigned to the Residential class for meter reading is a factor of 1 and represents meter reading in a Smart Meter environment. HCHI has calculated the costs to read a Smart Meter and weighted the costs of the remaining meter reading types against this cost to determine weighting factors by meter reading type. Additional meter reading types represent the manual reads for the General Service 50 to 4,999 kW customer rate class that do not have an interval meter, rural and in-town, and the interval meter reads. Table 4 details the weighting factors assigned to each type of meter read used in HCHI's 2014 Model.

Table 4
Meter Reading Weighting Factors

Customer Class	HCHI Meter Reading Weighting Factors
Smart Meter	1.00
General Service Walking (In-Town) with Other Services	1.33
General Service Vehcile (Rural) with Other Services	2.56
Interval - Daily Reads	54.28
Interval - Interrogations	51.90

2014 COST ALLOCATION UPDATES

As commented on in the Overview section of this Exhibit, HCHI has completed an updated Cost Allocation Model using version 3.1 issued August 2, 2013 with data for the 2014 Test Year on all input worksheets. The data used is consistent with the 2014 Test Year information that forms part of this Application. Inputs into the trial balance include: (i) 2014 cost information; (ii) 2014 forecasted assets allocated into primary and secondary distribution functions, as well as for capital contributions, depreciation, and accumulated depreciation; (iii) weighting factors specific to HCHI for services, billing and collecting, meter reading and meter capital (as discussed in Tab 1, Schedule 2 of this Exhibit); (iv) 2014 forecasted customer information; and (v) the load profile previously generated by Hydro One Networks Inc. ("HONI") on behalf of HCHI updated for 2014 load information; that is, the load profile used in the original 2007 informational filing but now scaled to match the 2014 load forecast. Table 5 below outlines the scaling factors used by rate class.

Table 5
Load Profile Scaling Percentages

Customer Class	2004 Weather Normal Values (kWh)	2014 Weather Normal Values (kWh)	Scaling Percentage
Residential	184,896,586	169,003,519	91.40%
General Service Less Than 50 kW	56,326,149	53,925,141	95.74%
General Service 50 to 4,999 kW	140,653,508	121,879,907	86.65%
Street Lighting	2,263,805	2,387,575	105.47%
Sentinel Lighting	600,812	327,143	54.45%
Unmetered Scattered Load	539,838	350,238	64.88%
Embedded Distributor - Hydro One Networks Inc.	65,305,781	72,629,941	111.22%
Note: Embedded Distributor 2004 kWh are for Norfolk Power Distribution Inc.			

Embedded Distributor – Hydro One Networks Inc.

As part of HCHI's 2010 COS rate application, (EB-2009-0265), a new rate class was approved for the Embedded Distributor – Hydro One Networks Inc. ("HONI"). Costs and applicable assets were allocated on a direct allocation basis using input worksheet "I9 – Direct Allocation in the 2010 Cost Allocation Model. In order to allocate costs associated with this new rate class, HCHI had to allocate HONI's share of costs that were attributable to the assets providing the low voltage services to HONI and all other related costs associated with providing this low voltage service. A utilization factor of the low voltage lines was used based on HONI's consumption (kWh) passing through the low voltage lines as compared to the combined consumption (kWh) of both HCHI and HONI passing through those same lines. One additional factor used to allocate costs was the line length kilometres (km) of HCHI's distribution assets that were providing the low voltage service as a percentage of HCHI's total line length km in that same asset class in HCHI's distribution system. HCHI wanted to ensure that the existing customer rate classes did not subsidize the "new" Embedded Distributor rate class applicable to HONI, and did so by directly allocating those costs and portion of assets associated with providing the low voltage service to HONI. This direct allocation removes those costs and assets from the total that is allocated to the balance of HCHI's customer rate classes. This same format approved in its 2010 COS rate application has been followed by HCHI for updating its 2014 Cost Allocation Model. Allocated costs and apportioned assets have been assigned to this class on a direct allocation basis using input worksheet "I9 – Direct Allocation" in the Model. The Embedded Distributor - HONI rate class has been included on all applicable sheets in HCHI's 2014 Model as a customer class along with HCHI's other customer classes in order to produce accurate revenue-to-cost ratios for all classes.

Per the Board's letter issued July 16, 2013, "*Allocation of Host Electricity Distributor Costs to Embedded Distributors* (EB-2010-0219), HCHI has not consulted with its Embedded Distributor - HONI prior to preparing its Cost Allocation Model as part of this

Application. HCHI did not feel that this was necessary, as at the time of this filing, it has a separate Board Approved rate class for its embedded distributor. This is consistent with the Board's approach as stated in the letter is as follows:

> *"… Accordingly, the Board will revise its filing requirements for electricity rate applications to make provision for the following to be filed by any host distributor that does not, at the time of filing, have a separate Board-approved rate class for its embedded distributor(s):*
>
> 5. *Evidence that the host distributor has consulted with its embedded distributor(s) prior to preparing its cost allocation model and filing its rate application, and a statement as to whether the embedded distributor supports the host distributor's approach to the allocation of costs to it."*

Street Lighting

As encouraged in the Filing Requirements, HCHI has taken into consideration that the Revenue Requirement of the Street Lighting class is sensitive to inputs related to the number of connections versus the number of devices and has entered the appropriate information in sheet "I6.2 Customer Data".

Customer Classes

HCHI is not proposing any new customer rate classes nor eliminating any existing customer rate classes in this Application.

HCHI has also not included the microFIT class as a separate class in the 2014 Cost Allocation Model, in accordance with the Board's instructions.

Sheet "I3 TB Data" – Reclassification of Accounts

As discussed in Exhibit 2, Tab 2, Schedule 1, the 2013 Bridge Year and the 2014 Test Year capital contributions include amounts to be paid to Hydro One to install one feeder breaker position (M3) at the Dunnville Transformer Station ("TS") in conjunction with their rebuild of the TS, ready for connection by HCHI. HCHI would be responsible for the costs of providing and installing the feeder to connect to Hydro One's breaker position, as well as the revenue metering outside the TS. HCHI has included this capital contribution in account 1609 and is requesting as part of this Application for it to be included in rate base. HCHI understands that this type of capital expenditure has been approved in the past in other utilities rate applications as a rate base item. The Model does not include account 1609 in the rate base calculation for cost allocation purposes. Therefore, HCHI has included the 2014 Test Year cost of $250,673 in account 1610 "Miscellaneous Intangible Plant" on sheet "I3 TB Data" but then reclassified it to account 1906 "Land Rights"" in order that the Model allocate it properly to the customer rate classes as part of rate base.

Sheet "I3 TB Data" – Account Allocator

As per the instruction sheet in the Model, HCHI has separated the "Account Setup Charges" revenue portion of account 4235 by using the reclassification column in the Model. These amounts are shown on row 284 account 4235-1 with an account allocator of CWNB – customer weighted number of bills. HCHI has also reclassified the microFIT monthly service charge revenue posted to this account on row 285 account 4235-90 with an account allocator of OM&A.

HCHI left a balance in the main account 4235 on row 283 of $28,995 which represents Reconnection Fee revenue collected from customers. The account allocator for this row is blank in the Model. HCHI has input this account allocator as CWNB – customer weighted number of bills. HCHI believes that this is the most appropriate account allocator for this type of revenue since a reconnection fee is only collected from a

customer if there has been a disconnection due to non-payment of a past due account / bill.

SUMMARY OF RESULTS AND PROPOSED CHANGES

The results of a cost allocation study are typically presented in the form of revenue-to-cost ratios. This ratio is shown by rate classification and is the percentage of distribution revenue collected by the rate classification as compared to the costs allocated to that classification. The percentage identifies the rate classifications that are being subsidized and those that are over-contributing. A percentage of less than 100% means that the rate classification is under-contributing and is being subsidized by other classes of customers. A percentage of greater than 100% indicates that the rate classification is over-contributing and is subsidizing other classes of customers.

Table 6 details the allocated costs by rate class for the 2010 COS rate application and now updated for this Application. This information is consistent with the details in Appendix 2-P "Cost Allocation".

Table 6
Allocated Cost by Customer Class

Customer Class	2010 Allocated Costs	%	2014 Allocated Costs	%
Residential	$ 9,256,358	67.39%	$ 9,745,962	69.55%
General Service Less Than 50 kW	$ 2,195,844	15.99%	$ 1,865,501	13.31%
General Service 50 to 4,999 kW	$ 1,409,865	10.26%	$ 1,431,979	10.22%
Street Lighting	$ 465,608	3.39%	$ 399,236	2.85%
Sentinel Lighting	$ 204,538	1.49%	$ 176,206	1.26%
Unmetered Scattered Load	$ 30,758	0.22%	$ 24,639	0.18%
Embedded Distributor - Hydro One Networks Inc.	$ 172,921	1.26%	$ 369,092	2.63%
Total	$ 13,735,892	100.00%	$ 14,012,615	100.00%

In the March 31, 2011 Report of the Board on Cost Allocation released in relation to EB-2010-0219 (the "March Report"), the Board established what it considered to be the appropriate ranges of revenue-to-cost ratios. Table 7 summarizes the established ranges from the March Report, HCHI's Board Approved 2011 revenue-to-cost ratios from its 2011 Incentive Rate Mechanism ("IRM3") rate application (EB-2010-0086), the

updated 2014 Cost Allocation Model revenue-to-cost ratios, and HCHI's proposed revenue-to-cost ratios for each of 2014 and 2015. The most recent Board Approved revenue-to-cost ratios reported are from the 2011 IRM3 instead of the 2010 COS rate application as this was the last of the two rate years to move the revenue-to-cost ratios for the Street Lighting and Sentinel Lighting classes to the bottom of the range at 70%.

Table 7
Revenue-to-Cost Ratios

Customer Class	2011 IRM3 Board Approved	2014 Cost Allocation Study	2014 Proposed Ratios	2015 Proposed Ratios	Board Targets (Min.to Max.)
	%	%	%	%	%
Residential	99.86	96.87	100.00	100.00	85 - 115
General Service Less Than 50 kW	101.78	111.87	100.00	100.00	80 - 120
General Service 50 to 4,999 kW	112.88	128.55	105.90	105.20	80 - 120
Street Lighting	70.00	86.31	86.30	86.30	70 - 120
Sentinel Lighting	70.00	69.27	74.60	80.00	80 - 120
Unmetered Scattered Load	80.81	80.63	80.60	80.60	80 - 120
Embedded Distributor - Hydro One Networks Inc.	100.00	42.10	105.50	105.50	80 - 120

HCHI is proposing in this Application to re-align its revenue-to-cost ratios by adjusting the allocations of revenue among classes in order to reduce some of the cross-subsidization that is occurring and to bring those classes that are outside of the Board's targets within them.

Specifically, the Sentinel Lighting and Embedded Distributor - HONI rate classes are under contributing and outside of the Board's targets while the two General Service rate classes are over contributing but are within the Board's targets. HCHI is proposing to move the General Service Less Than 50 kW class down to 100% and align it with the Residential class by moving it up to 100%. The Residential class is slightly below the 100% at 96.87%. The Sentinel Lighting class will move to the bottom range of the Board's target in two stages by moving them to approximately 50% between their current ratio and the lower limit of the target range in year one (2014) and to the bottom target of 80% in year two (2015).

The additional revenue from the under contributing class will be distributed to the General Service 50 to 4,999 kW customer rate class that has been over contributing; that is, the class with the highest level of over contribution. This reallocation will occur in the 2014 Test Year, as well as in rate year two 2015, to offset the adjustment to the under contributing rate class, Sentinel Lighting, in both of these same years.

HCHI is proposing to move the Embedded Distributor - HONI rate class to relatively the same ratio as the General Service 50 to 4,999 kW customer rate class. This would be the rate class that the Embedded Distributor would have the most similar characteristics with. HCHI has been experiencing a large under contribution from this class in its revenue-to-cost ratio since 2010. This can be attributed to two main factors, including (i) the overstatement of the load as provided by HONI and approved in HCHI's 2010 COS rate application; and (ii) the sub-transmission costs charged by HONI that are part of the cost for HCHI to serve the Embedded Distributor – HONI. Seven of the eight embedded points are connected to HONI feeders and HCHI is charged sub-transmission charges on this embedded load by HONI. These costs were factored into the wheeling charge calculation in 2010 but at the approved rates at that time. Those rates have increased since the wheeling charge was originally approved. The forecasted load in the 2010 COS rate application did not materialize and HCHI was unable to collect the revenue it should have to cover the costs allocated to the Embedded Distributor – HONI rate class for the past four years.

HCHI did not adjust the revenue-to-cost ratios of the Unmetered Scattered Load and Street Lighting customer rate classes as their ratios were above the bottom range of the Board's targets and would be comparable with the Sentinel Lighting customer rate class after its two year adjustment.

The following Table 8 provides information on calculated class revenue. The resulting 2014 proposed base revenue will be the amount used in Exhibit 8 to design the proposed distribution rates in this Application.

Table 8
2014 Test Year Revenue by Customer Class

Customer Class	2014 Base Revenue at Existing Rates	2014 Proposed Base Revenue Allocated Based on Proporation of Revenue at Existing Rates	2014 Proposed Base Revenue	Proposed Miscellaneous Revenue
Residential	$ 8,571,640	$ 8,589,830	$ 8,892,831	$ 853,131
General Service Less Than 50 kW	$ 1,928,924	$ 1,933,017	$ 1,711,607	$ 153,894
General Service 50 to 4,999 kW	$ 1,751,698	$ 1,755,415	$ 1,430,483	$ 85,425
Street Lighting	$ 321,316	$ 321,998	$ 321,966	$ 22,575
Sentinel Lighting	$ 108,730	$ 108,961	$ 118,345	$ 13,105
Unmetered Scattered Load	$ 17,943	$ 17,981	$ 17,974	$ 1,885
Embedded Distributor - Hydro One Networks Inc.	$ 147,037	$ 147,349	$ 381,346	$ 8,046
Total	$ 12,847,288	$ 12,874,551	$ 12,874,552	$ 1,138,061

Cost Allocation Summary

The discussion and Tables above support HCHI's proposed reallocation of distribution revenues across customer classes, in order to begin moving toward revenue-to-cost ratios of 100% and reduce cross-subsidization. HCHI submits that the proposed reallocation of distribution revenue is fair and reasonable for the following reasons:

- Customer class revenues will more closely reflect the actual costs of providing distribution service to that class;
- The reallocation to the Sentinel Lighting customer rate class continues into 2015 with proposed offsets to the General Service 50 to 4,999 kW rate class; and
- Allocation of direct costs associated with the Embedded Distributor - HONI rate class and the movement of their revenue-to-cost ratio will avoid other customer rate classes subsidizing this class.

HCHI has included Input Sheets I-6 and I-8 as Appendix A to this Exhibit and Output Sheets O-1 and O-2 as Appendix B to this Exhibit as required in the Filing Requirements.



2014 Cost Allocation Model

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Sheet I6.1 Revenue Worksheet - 2014 Cost of Service Rate Application

Total kWhs from Load Forecast	420,503,464
Total kWs from Load Forecast	577,596
Deficiency/sufficiency (RRWF 8. cell F51)	- 27,263
Miscellaneous Revenue (RRWF 5. cell F48)	1,138,061

			1	2	3	7	8	9	10
	ID	**Total**	**Residential**	**General Service Less Than 50 kW**	**General Service 50 to 4,999 kW**	**Street Lighting**	**Sentinel Lighting**	**Unmetered Scattered Load**	**Embedded Distributor - Hydro One Networks Inc.**
Billing Data									
Forecast kWh	**CEN**	420,503,464	169,003,519	53,925,141	121,879,907	2,387,575	327,143	350,238	72,629,941
Forecast kW	**CDEM**	577,596			342,324	6,648	909		227,715
Forecast kW, included in CDEM, of customers receiving line transformer allowance		153,836			153,836				
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-							
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	347,873,523	169,003,519	53,925,141	121,879,907	2,387,575	327,143	350,238	
Existing Monthly Charge			$18.17	$29.04	$104.06	$6.09	$12.99	$20.83	$184.32
Existing Distribution kWh Rate			$0.0265	$0.0205				$0.0027	
Existing Distribution kW Rate					$4.8286	$15.5853	$33.5294		$0.5680
Existing TOA Rate					$0.60				
Additional Charges									
Distribution Revenue from Rates		$12,939,590	$8,571,640	$1,928,924	$1,844,000	$321,316	$108,730	$17,943	$147,037
Transformer Ownership Allowance		$92,301	$0	$0	$92,301	$0	$0	$0	$0
Net Class Revenue	**CREV**	$12,847,288	$8,571,640	$1,928,924	$1,751,699	$321,316	$108,730	$17,943	$147,037



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Sheet I6.2 Customer Data Worksheet - 2014 Cost of Service Rate Application

			1	2	3	7	8	9	10
	ID	Total	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load	Embedded Distributor - Hydro One Networks Inc.
Billing Data									
Bad Debt 3 Year Historical Average	BDHA	$61,413	$48,814	$8,417	$4,182	$0	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$65,395	$50,335	$10,451	$4,524	$35	$26	$24	$0
Number of Bills (customer # * 12 mos)	CNB	262,416	225,264	28,356	1,836	24	6,024	816	96
Number of Devices						2,979		68	
Number of Connections (Unmetered)	CCON	2,039				1,469	502	68	
Total Number of Customers	CCA	21,868	18,772	2,363	153	2	502	68	8
Bulk Customer Base	CCB	-							
Primary Customer Base	CCP	21,860	18,772	2,363	153	2	502	68	
Line Transformer Customer Base	CCLT	21,830	18,772	2,363	123	2	502	68	
Secondary Customer Base	CCS	19,265	17,307	1,382	4	2	502	68	
Weighted - Services	CWCS	20,435	17,307	1,451	5	1,205	412	56	-
Weighted Meter -Capital	CWMC	6,957,020	4,756,307	1,326,685	683,704	-	-	-	190,325
Weighted Meter Reading	CWMR	25,625	18,772	3,056	3,382	-	-	-	415
Weighted Bills	CWNB	264,469	225,264	29,774	1,946	71	6,506	840	67

Bad Debt Data

Historic Year:	2010	55,600	48,632	6,968	-				
Historic Year:	2011	54,192	44,136	5,476	4,580				
Historic Year:	2012	74,446	53,673	12,805	7,967				
Three-year average		**61,413**	**48,814**	**8,417**	**4,182**	**-**	**-**	**-**	**-**



2014 Cost Allocation Model

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Sheet I8 Demand Data Worksheet - 2014 Cost of Service Rate Application

This is an input sheet for demand allocators.

CP TEST RESULTS	12 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

Customer Classes		Total	1 Residential	2 General Service Less Than 50 kW	3 General Service 50 to 4,999 kW	7 Street Lighting	8 Sentinel Lighting	9 Unmetered Scattered Load	10 Embedded Distributor - Hydro One Networks Inc.
CO-INCIDENT PEAK									
1 CP									
Transformation CP	TCP1	-	-	-	-	-	-	-	
Bulk Delivery CP	BCP1	-	-	-	-	-	-	-	
Total Sytem CP	DCP1	62,694	35,337	11,465	15,851	-	-	41	
4 CP									
Transformation CP	TCP4	-	-	-	-	-	-	-	
Bulk Delivery CP	BCP4	-	-	-	-	-	-	-	
Total Sytem CP	DCP4	238,075	138,697	38,216	59,744	1,107	153	158	
12 CP									
Transformation CP	TCP12	-	-	-	-	-	-	-	
Bulk Delivery CP	BCP12	-	-	-	-	-	-	-	
Total Sytem CP	DCP12	638,464	358,988	97,813	176,306	4,288	590	479	
NON CO_INCIDENT PEAK									
1 NCP									
Classification NCP from Load Data Provider	DNCP1	72,755	36,998	13,461	21,616	556	82	42	
Primary NCP	PNCP1	72,755	36,998	13,461	21,616	556	82	42	
Line Transformer NCP	LTNCP1	68,517	36,998	13,461	17,378	556	82	42	
Secondary NCP	SNCP1	43,229	34,111	7,873	565	556	82	42	
4 NCP									
Classification NCP from Load Data Provider	DNCP4	274,734	141,693	49,880	80,460	2,218	317	166	
Primary NCP	PNCP4	274,734	141,693	49,880	80,460	2,218	317	166	
Line Transformer NCP	LTNCP4	258,958	141,693	49,880	64,684	2,218	317	166	
Secondary NCP	SNCP4	164,612	130,635	29,172	2,104	2,218	317	166	
12 NCP									
Classification NCP from Load Data Provider	DNCP12	726,600	372,970	126,223	219,381	6,638	909	479	
Primary NCP	PNCP12	726,600	372,970	126,223	219,381	6,638	909	479	
Line Transformer NCP	LTNCP12	683,584	372,970	126,223	176,365	6,638	909	479	
Secondary NCP	SNCP12	431,445	343,863	73,821	5,735	6,638	909	479	



2014 Cost Allocation Model

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Sheet O1 Revenue to Cost Summary Worksheet - 2014 Cost of Service Rate Application

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 General Service Less Than 50 kW	3 General Service 50 to 4,999 kW	7 Street Lighting	8 Sentinel Lighting	9 Unmetered Scattered Load	10 Embedded Distributor - Hydro One Networks Inc.
crev	Distribution Revenue at Existing Rates	$12,847,288	$8,571,640	$1,928,924	$1,751,699	$321,316	$108,730	$17,943	$147,037
mi	Miscellaneous Revenue (mi)	$1,138,061	$853,131	$153,894	$85,426	$22,575	$13,105	$1,885	$8,046
		Miscellaneous Revenue Input equals Output							
	Total Revenue at Existing Rates	$13,985,349	$9,424,772	$2,082,818	$1,837,124	$343,891	$121,835	$19,827	$155,083
	Factor required to recover deficiency (1 + D)	1.0021							
	Distribution Revenue at Status Quo Rates	$12,874,553	$8,589,831	$1,933,017	$1,755,416	$321,998	$108,961	$17,981	$147,349
	Miscellaneous Revenue (mi)	$1,138,061	$853,131	$153,894	$85,426	$22,575	$13,105	$1,885	$8,046
	Total Revenue at Status Quo Rates	$14,012,614	$9,442,962	$2,086,911	$1,840,842	$344,573	$122,066	$19,866	$155,395
	Expenses								
di	Distribution Costs (di)	$4,109,705	$2,841,052	$550,889	$496,911	$158,820	$54,273	$7,760	$0
cu	Customer Related Costs (cu)	$1,956,106	$1,565,780	$249,413	$91,499	$1,528	$29,536	$3,818	$14,532
ad	General and Administration (ad)	$2,406,863	$1,683,876	$306,834	$226,659	$62,021	$31,957	$4,419	$91,098
dep	Depreciation and Amortization (dep)	$2,113,191	$1,457,594	$312,390	$240,990	$63,506	$21,702	$3,102	$13,906
INPUT	PILs (INPUT)	$100,333	$69,185	$14,040	$11,834	$3,569	$1,220	$174	$312
INT	Interest	$1,157,401	$798,086	$161,957	$136,516	$41,167	$14,068	$2,011	$3,596
	Total Expenses	$11,843,600	$8,415,573	$1,595,523	$1,204,409	$330,611	$152,755	$21,286	$123,444
	Direct Allocation	$239,654	$0	$0	$0	$0	$0	$0	$239,654
NI	Allocated Net Income (NI)	$1,929,360	$1,330,389	$269,978	$227,570	$68,625	$23,451	$3,353	$5,994
	Revenue Requirement (includes NI)	$14,012,614	$9,745,962	$1,865,501	$1,431,979	$399,236	$176,206	$24,639	$369,092
		Revenue Requirement Input equals Output							
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	$72,045,597	$49,728,450	$10,054,017	$8,513,417	$2,590,972	$885,411	$126,603	$146,727
gp	General Plant - Gross	$10,931,688	$7,546,439	$1,524,209	$1,280,103	$390,892	$133,579	$19,092	$37,376
accum dep	Accumulated Depreciation	($31,324,039)	($21,563,389)	($4,374,198)	($3,750,875)	($1,130,499)	($386,324)	($55,283)	($63,470)
co	Capital Contribution	($5,002,511)	($3,516,384)	($673,754)	($540,190)	($189,957)	($64,914)	($9,240)	($8,072)
	Total Net Plant	$46,650,736	$32,195,117	$6,530,274	$5,502,454	$1,661,408	$567,751	$81,172	$112,560
	Directly Allocated Net Fixed Assets	$33,964	$0	$0	$0	$0	$0	$0	$33,964
COP	Cost of Power (COP)	$46,008,158	$21,954,954	$6,965,797	$15,714,094	$321,855	$46,971	$45,806	$958,681
	OM&A Expenses	$8,472,675	$6,090,708	$1,107,136	$815,068	$222,369	$115,766	$15,998	$105,630
	Directly Allocated Expenses	$233,816	$0	$0	$0	$0	$0	$0	$233,816
	Subtotal	***$54,714,649***	***$28,045,662***	***$8,072,933***	***$16,529,163***	***$544,224***	***$162,737***	***$61,803***	***$1,298,127***
	Working Capital	$7,112,904	$3,645,936	$1,049,481	$2,148,791	$70,749	$21,156	$8,034	$168,757
	Total Rate Base	$53,797,604	$35,841,053	$7,579,755	$7,651,245	$1,732,157	$588,907	$89,206	$315,280
		Rate Base Input equals Output							
	Equity Component of Rate Base	$21,519,042	$14,336,421	$3,031,902	$3,060,498	$692,863	$235,563	$35,683	$126,112
	Net Income on Allocated Assets	$1,929,048	$1,027,390	$491,389	$636,432	$13,962	($30,690)	($1,420)	($208,015)
	Net Income on Direct Allocation Assets	$3,050	$0	$0	$0	$0	$0	$0	$3,050
	Net Income	$1,932,098	$1,027,390	$491,389	$636,432	$13,962	($30,690)	($1,420)	($204,964)
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES STATUS QUO%	100.00%	96.89%	111.87%	128.55%	86.31%	69.27%	80.63%	42.10%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($27,265)	($321,191)	$217,317	$405,145	($55,345)	($54,371)	($4,811)	($214,009)



2014 Cost Allocation Model

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Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - 2014 Cost of Service Rate Application

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	7	8	9	10
	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load	Embedded Distributor - Hydro One Networks Inc.
Customer Unit Cost per month - Avoided Cost	$6.60	$10.03	$68.24	$0.03	$3.83	$3.54	$338.17
Customer Unit Cost per month - Directly Related	$9.02	$13.39	$89.88	$0.06	$5.33	$4.97	$418.66
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$22.42	$24.79	$88.25	$14.94	$21.39	$18.52	$419.46
Existing Approved Fixed Charge	$18.17	$29.04	$104.06	$6.09	$12.99	$20.83	$184.32

Exhibit 8 – Rate Design

	Tab	Schedule	Appendix
Rate Design Overview	1	1	
Proposed Changes to Distribution Rates		2	
Other Electricity Charges		3	
Retail Transmission Service Rates Work Form – All Customer Classes except Embedded Distributor			A
Retail Transmission Service Rates Work Form – Embedded Distributor – Hydro One Networks Inc.			B
Determination of Total Loss Factor		4	
Rate Mitigation		5	
Existing Rate Classes and Rate Schedule	2	1	
Ontario Energy Board-Approved Tariff of Rates and Charges Effective May 1, 2013			C
Proposed Rate Classes and Rate Schedule		2	
Proposed Tariff of Rates and Charges			D
Track Changes of Current Rates to Proposed Rates			E
Revenue Reconciliation	3	1	
Rate and Bill Impacts	4	1	
Bill Impacts			F

RATE DESIGN OVERVIEW

This Exhibit documents the calculation of Haldimand County Hydro Inc's ("HCHI's") proposed distribution rates by customer rate class for the 2014 Test Year, based on the allocation of the base revenue requirement across the customer rate classes according to the revenue-to-cost ratios as proposed in Exhibit 7 – Cost Allocation and rate design as proposed in this Exhibit.

HCHI has determined its 2014 total Service Revenue Requirement to be $14,012,613. The 2014 Revenue Offsets in the amount of $1,138,061 reduce HCHI's total Service Revenue Requirement to a 2014 Base Revenue Requirement of $12,874,552, which is used to determine the proposed distribution rates. The Base Revenue Requirement is derived from HCHI's 2014 capital and operating forecasts, weather normalized usage, forecasted customer counts, calculated Payments in Lieu of Taxes ("PILs") and regulated return on rate base. HCHI's 2014 Revenue Requirement is summarized in Table 1 below:

Table 1
Calculation of Base Revenue Requirement

OM&A Expenses	$	8,706,491
Depreciation Expenses		2,113,988
Total Distribution Expenses	$	10,820,479
Regulated Return On Capital	$	3,091,641
PILs		100,492
Service Revenue Requirement	$	14,012,612
Less: Revenue Offsets		(1,138,061)
Base Revenue Requirement	**$**	**12,874,551**

The Base Revenue Requirement is allocated to the various customer rate classes using the following proposed apportionment of revenue as detailed in Exhibit 7 – Cost Allocation.

Table 2
Proposed Apportionment of Revenue to Customer Rate Classes

Customer Class	2014 Proposed Revenue Allocation	2014 Proposed Base Revenue Requirement
Residential	69.07%	$ 8,892,831
General Service Less Than 50 kW	13.30%	$ 1,711,607
General Service 50 to 4,999 kW	11.11%	$ 1,430,483
Street Lighting	2.50%	$ 321,966
Sentinel Lighting	0.92%	$ 118,345
Unmetered Scattered Load	0.14%	$ 17,974
Embedded Distributor - Hydro One Networks Inc.	2.96%	$ 381,346
Total	100.00%	$ 12,874,552

HCHI has proposed a re-alignment of the Base Revenue Requirement in Exhibit 7 – Cost Allocation in order to better align the revenue-to-cost contribution of each customer rate class. Partial reallocation will result in a reduction to the total monthly bill for the General Service 50 to 4,999 kW customer rate class and an increase to the Sentinel Lighting and Embedded Distributor – Hydro One Networks Inc. ("HONI") customer rate classes. The Sentinel Lighting customer rate class will experience the greatest total bill impact of approximately 11.67% based on a typical usage. The revenue-to-cost ratios have been increased in order to comply with the target ranges the Board has set for cost allocation as illustrated in Table 7 of Exhibit 7 – Cost Allocation.

It would be inappropriate to leave the revenue-to-cost ratios as they currently exist and continue to have certain customer rate classes, specifically the General Service classes, subsidizing the Sentinel Lighting and Embedded Distributor - HONI customer rate classes.

PROPOSED CHANGES TO DISTRIBUTION RATES

Determination of Monthly Fixed / Volumetric Charges

HCHI's current Board Approved distribution volumetric and monthly service charges (as per the 2013 Tariff of Rates and Charges (EB-2012-0129) for rates effective May 1, 2013) are summarized in Table 3 below. The fixed / variable analysis that follows is net of all rate adders, funding adders, and rate riders.

Table 3
Monthly Fixed and Volumetric Charges
(Rates effective May 1, 2013)

Customer Class	Billing Determinant	Monthly Service Charge	Billing Determinant	Volumetric Charge
Residential	Customer	$ 18.17	kWh	$ 0.0265
General Service Less Than 50 kW	Customer	$ 29.04	kWh	$ 0.0205
General Service 50 to 4,999 kW	Customer	$ 104.06	kW	$ 4.8286
Street Lighting	Connection	$ 6.09	kW	$ 15.5853
Sentinel Lighting	Connection	$ 12.99	kW	$ 33.5294
Unmetered Scattered Load	Connection	$ 20.83	kWh	$ 0.0027
Embedded Distributor - Hydro One Networks Inc.	Customer	$ 184.32	kW	$ 0.5680

Using the existing approved monthly service charges applied to the forecast number of customers and/or connections for 2014, and the approved distribution volumetric charges applied to the forecast volumetric billing determinants, including kWh and kW, the following Table 4 outlines the current proportion between the fixed and variable distribution revenue by customer rate class.

Table 4
Current Fixed and Variable Distribution Revenue Proportion

Customer Class	Current Fixed Revenue Proportion	Current Variable Revenue Proportion
Residential	47.75%	52.25%
General Service Less Than 50 kW	42.69%	57.31%
General Service 50 to 4,999 kW	10.91%	89.09%
Street Lighting	67.75%	32.25%
Sentinel Lighting	71.97%	28.03%
Unmetered Scattered Load	94.73%	5.27%
Embedded Distributor - Hydro One Networks Inc.	12.03%	87.97%

Proposed Monthly Fixed Charges

Consistent with the 2011 COS rate application Board Decisions for Hydro One Brampton, Kenora Hydro, and Horizon Utilities, the Board's Decision on Atikokan Hydro's 2012 COS rate application, and the Board's recent Decision on Centre Wellington Hydro's 2013 COS rate application, HCHI proposes to maintain the current fixed / variable proportions for all rate classes. Table 5 outlines the calculation of the proposed monthly service charge by customer rate class.

Table 5
Proposed Monthly Service Charge

Customer Class	2014 Proposed Base Revenue Requirement	Fixed Revenue Proportion	2014 Proposed Fixed Revenue	Customers / Connections	Proposed Monthly Service Charge
Residential	$ 8,892,831	47.75%	$ 4,246,419	18,772	$ 18.85
General Service Less Than 50 kW	$ 1,711,607	42.69%	$ 730,686	2,363	$ 25.77
General Service 50 to 4,999 kW	$ 1,430,483	10.91%	$ 156,020	153	$ 84.98
Street Lighting	$ 321,966	67.75%	$ 218,145	2,979	$ 6.10
Sentinel Lighting	$ 118,345	71.97%	$ 85,172	502	$ 14.14
Unmetered Scattered Load	$ 17,974	94.73%	$ 17,027	68	$ 20.87
Embedded Distributor - Hydro One Networks Inc.	$ 381,346	12.03%	$ 45,892	8	$ 478.04
Total	$ 12,874,552		$ 5,499,361		

Table 6 below compares the current and proposed monthly fixed charges with the floor and ceiling amounts as calculated in the 2014 Cost Allocation Model.

Table 6
Monthly Service Charge Comparison – Proposed, Floor and Ceiling

Customer Class	Current Monthly Service Charge	Proposed Monthly Service Charge	Floor (Customer Unit Cost / month - Avoided Cost)	Ceiling (Customer Unit Cost / month - Minimum System with PLCC Adj.)
Residential	$ 18.17	$ 18.85	$ 6.60	$ 22.43
General Service Less Than 50 kW	$ 29.04	$ 25.77	$ 10.03	$ 24.80
General Service 50 to 4,999 kW	$ 104.06	$ 84.98	$ 68.24	$ 88.27
Street Lighting	$ 6.09	$ 6.10	$ 0.03	$ 14.93
Sentinel Lighting	$ 12.99	$ 14.14	$ 3.83	$ 21.39
Unmetered Scattered Load	$ 20.83	$ 20.87	$ 3.54	$ 18.53
Embedded Distributor - Hydro One Networks Inc.	$ 184.30	$ 478.04	$ 338.20	$ 418.78

The rationale for exceeding the ceiling is in order to maintain the fixed / variable split which is reflected in rates. In HCHI's view, using the current fixed / variable split will better manage the volume risk on distribution revenue; that is as opposed to using the ceiling. In addition, the Board has approved the fixed / variable split in a number of cases even when in some cases the resulting monthly service charge exceeded the ceiling. Also, as part of the Renewed Regulatory Framework for Electricity, the Board has initiated a project to complete the work begun in its Revenue Decoupling for Distributors (EB-2010-0060) which could impact the fixed / variable split. As a result, HCHI's view is that the fixed / variable split should be maintained for the purposes of this Application.

Proposed Volumetric Charges

The variable (i.e. volumetric) component of the distribution charge is calculated by dividing the variable distribution portion of the Base Revenue Requirement by the appropriate 2014 Test Year usage, either kWh or kW, as the class charge determinant. This calculation applies to all rate classes with the exception of the General Service 50

to 4,999 kW rate class which includes an adjustment for transformer ownership allowance.

The following Table 7 provides HCHI's calculations of its proposed distribution volumetric charges for the 2014 Test Year assuming the proposed fixed / variable split, as illustrated in Table 4 above, for each customer rate class.

Table 7
Proposed Distribution Volumetric Charge

Customer Class	2014 Proposed Base Revenue Requirement	Variable Revenue Proportion	Transformer Ownership Allowance	2014 Proposed Variable Revenue	2014 Billing Determinant (kWh or kW)	Unit of Measure	Proposed Volumetric Charge
Residential	$ 8,892,831	52.25%		$ 4,646,412	169,003,519	kWh	$ 0.0275
General Service Less Than 50 kW	$ 1,711,607	57.31%		$ 980,921	53,925,141	kWh	$ 0.0182
General Service 50 to 4,999 kW	$ 1,430,483	89.09%	$ 92,302	$ 1,366,765	342,324	kW	$ 3.9926
Street Lighting	$ 321,966	32.25%		$ 103,821	6,648	kW	$ 15.6168
Sentinel Lighting	$ 118,345	28.03%		$ 33,173	909	kW	$ 36.4943
Unmetered Scattered Load	$ 17,974	5.27%		$ 947	350,238	kWh	$ 0.0027
Embedded Distributor - Hydro One Networks Inc.	$ 381,346	87.97%		$ 335,454	227,715	kW	$ 1.4731
Total	$ 12,874,552			$ 7,467,493			

Transformer Ownership Allowance

Currently, HCHI provides a Transformer Ownership Allowance to those customers that own their transformation facilities and whose billing determinant is kW. HCHI proposes to maintain the current approved transformer ownership allowance of $0.60 per kW which currently only applies to the General Service 50 to 4,999 kW customer rate class. The transformer ownership allowance is intended to reflect the costs to a distributor of providing step down transformation facilities to the customer's utilization voltage level. Since the distributor provides electricity at utilization voltage, the cost of this transformation is captured in, and recovered through, the distribution rates. Therefore, when a customer provides its own step down transformation from primary to secondary,

it should receive a credit for the component of these costs already included in the distribution rates.

In order to ensure that HCHI collects the proposed distribution revenue assigned to the customer rate class which provides a transformer ownership allowance, the total amount or "cost" of the transformer ownership allowance for the rate class needs to be collected in the distribution volumetric rates from all customers in that particular rate class. This will allow HCHI to collect distribution revenue from the rate class at the "gross" level. The transformer ownership allowance provided will reduce the gross distribution revenue to a "net" level. The net level will be equivalent to the proposed distribution revenue assigned to that customer rate class. As a result, the amount of the transformer ownership allowance expected to be provided to those General Service 50 to 4,999 kW customers that own their own transformer is included in the volumetric charge for that class. The proposed volumetric charge in Table 7 above includes the cost of the transformer ownership allowance and is the applied for distribution volumetric rate of $3.9926 per kW.

Proposed Distribution Rates

The following Table 8 sets out HCHI's proposed 2014 electricity distribution rates based on the foregoing calculations, including adjustments for the recovery of transformer ownership allowance and excluding any funding adders, rate riders, rate adders, or low voltage charges:

Table 8
Proposed 2014 Electricity Distribution Rates

	Fixed Distribution Charge		Variable Distribution Charge	
Customer Class	**Customer**	**Connection**	**kWh**	**kW**
Residential	$ 18.85		$ 0.0275	
General Service Less Than 50 kW	$ 25.77		$ 0.0182	
General Service 50 to 4,999 kW	$ 84.98			3.9926
Street Lighting		$ 6.10		15.6168
Sentinel Lighting		$ 14.14		36.4943
Unmetered Scattered Load		$ 20.87	$ 0.0027	
Embedded Distributor - Hydro One Networks Inc.	$ 478.04			1.4731

Proposed Deferral and Variance Account Rate Riders

HCHI has requested disposition of certain of its deferral and variance account balances as at December 31, 2012 with projected carrying charges calculated to April 30, 2014 as detailed in Exhibit 9 – Deferral and Variance Accounts at Tab 2, Schedules 3 and 4. The balance requested for disposition is a credit balance in the amount of $56,993, over the default disposition period of one year commencing May 1, 2014, applied as a volumetric rate rider. This disposition credit is net of the Lost Revenue Adjustment Mechanism Variance ("LRAMVA") debit of $83,818, inclusive of carrying charges, that is being requested for recovery as part of this Application. The LRAMVA requested for recovery is booked to variance account 1568 which is included in the Board's deferral and variance account model as part of the total disposition. This net credit rate rider would effectively provide HCHI's distribution customers with a credit for this one year rate period. The disposition amount excludes the deferral and variance accounts specific to the Embedded Distributor – HONI. As mentioned above in this Exhibit, HCHI tracks variances separately for the Embedded Distributor – HONI rate class. The balance requested for disposal for the deferral and variance accounts specific to the Embedded Distributor - HONI for the same period is a debit balance in the amount of

$119,861, over the default disposition period of one year commencing May 1, 2014, applied as a volumetric rate rider.

Proposed Property, Plant, & Equipment Adjustment Rate Rider

The Property, Plant, & Equipment ("PPE") Adjustment on account of HCHI's change in estimated useful lives is a credit adjustment of $1,459,184. As noted in Exhibit 2, Tab 5, Schedule 5, HCHI is not transitioning to International Financial Reporting Standards ("IFRS") until January 1, 2015 but has made the appropriate accounting changes under Canadian Generally Accepted Accounting Principles ("CGAAP") effective January 1, 2013 as mandated by the Board in its letter dated July 17, 2012. This PPE credit adjustment has been recorded to account 1576 Accounting Changes under CGAAP and included in the Board's deferral and variance account model, inclusive of the rate of return on this amount of $419,515, for a total credit of $1,878,699 as calculated in Appendix 2-EE "Account 1576 (2013)". The model calculates a credit rate rider for disposition over the 5 year rate term.

Proposed Stranded Meter Rate Rider

HCHI was approved for disposition of its smart meter costs (previously included in deferral accounts) effective November 1, 2012 in the Board's Decision and Order on HCHI's Smart Meter Cost Recovery application (EB-2012-0272) issued November 1, 2012. As part of this Decision HCHI was approved not to dispose of its stranded meters at that time but to deal with the disposition in its next cost of service. Therefore, HCHI has applied for disposition of its stranded meters, as part of this Application, with an estimated net book value of $479,441 as at December 31, 2013. HCHI is proposing disposition of this amount to the three applicable customer classes, including Residential, General Service Less Than 50 kW, and General Service 50 to 4,999 kW, over a one year disposition period commencing May 1, 2014. This is discussed in more detail in Exhibit 9, Tab 3, Schedule 1.

Proposed Renewable Generation Connection Funding Adder

As part of this Application, a Renewable Energy Generation ("REG") Plan has been completed and submitted as part of HCHI's Distribution System Plan ("DSP") included in Exhibit 2. This REG Plan forecasts Renewable Energy Improvement investments and Renewable Energy Expansion investments for the period 2014 to 2018 inclusive.

The 2014 Test Year direct benefit portion of the renewable energy improvement and expansion investments have been included in HCHI's 2014 rate base calculations as detailed in Exhibit 2, Tab 6, Schedule 1. For the direct benefit amounts related to the forecast period from 2015 to 2018 inclusive, HCHI is proposing a REG Funding Adder to be recovered over the 5 year rate term. For the 2014 Test Year and the period 2015 to 2018 inclusive, HCHI has applied for the portion to be recovered from provincial rate payers to be approved as part of this Application. HCHI will be required to record all provincial recovery amounts related to these REG investments for the period 2014 to 2018 inclusive and the direct benefit portion for the forecast period 2015 to 2018 inclusive into the Board Approved deferral account 1531 Renewable Connection Capital to be offset by any recoveries, both provincially and through direct benefits. Further details are provided in OEB Appendix 2-FA "Proposed REG Investments", 2-FB "Calculation of REG Improvement", and 2-FC "Calculation of REG Expansion", and in Exhibit 9, Tab 5.

All of the above proposed rate riders, LRAMVA recovery, funding adders and bill impacts are detailed in Exhibit 9 as well as shown in this Exhibit at Tab 2, Appendix D.

OTHER ELECTRICITY CHARGES

Retail Transmission Service Rates

Electricity distributors are charged the Ontario Uniform Transmission Rates ("UTRs") at the wholesale level and subsequently pass these charges on to their distribution customers through Retail Transmission Service Rates ("RTSRs"). For each distribution customer rate class there are two RTSRs, one for the Network charges and one for the Connection charges. The RTSR Network charge recovers the UTR wholesale network service charge, and the RTSR Connection charge recovers the UTR wholesale line and transformation connection charges. Deferral accounts capture timing and rate differences between the UTRs paid at the wholesale level and the RTSRs billed to distribution customers.

HCHI currently pays RTSR's to both the Independent Electricity System Operator ("IESO") and to HONI that are then passed onto HCHI's customers. As described in Exhibit 1, Tab 5, Schedule 6, some of the feeders from the 3 transformer stations are owned by HONI and hence HONI is the retail transmission customer at those feeders. HONI pays the IESO directly the RTSR's on those feeders calculated at the Ontario UTRs and passes those charges on to HCHI at HONI's approved RTSR rates. HCHI also pays RTSR's to both the IESO and to HONI for the embedded distributor load.

In accordance with the Filing Requirements and the Board's Guideline *G-2008-0001: Electricity Distribution Retail Transmission Service Rates, October 22, 2008* as revised June 28, 2012, HCHI is proposing to adjust the RTSRs for both Network and Connection as part of this Application.

HCHI currently has two sets of RTSRs for its General Service 50 to 4,999 kW customer class; including one for interval metered customers and one for non-interval metered customers. HCHI has chosen to harmonize these two sets of rates with this Application. All other rates for this customer rate class are the same regardless of type of meter.

HCHI does not see any reason why the RTSRs should remain separate. HCHI weighted 2012 actual charges for each of these meter types to calculate a harmonized rate. Bill impacts have been included in Tab 4 Schedule 1 of this Exhibit to show the impact for both types of metering within this customer class. Table 9 details the 2013 existing approved RTSRs for the General Service 50 to 4,999 kW customer class and the 2013 harmonized rate used to calculate the proposed 2014 RTSRs for this customer rate class.

Table 9
General Service 50 to 4,999 kW Harmonized 2013 RTSRs

Retail Transmission Network Service Rate	2012 Demand kW Billed / Unbilled	May 1, 2013 Rate	Total Calculated Charges	**Harmonized Rate RTSR-Network**
General Service 50 to 4,999 kW - Non - Interval Metered	91,666	$ 2.3783	$ 218,009.25	
General Service 50 to 4,999 kW - Interval Metered	240,823	$ 2.5228	607,548.26	
	332,489		$ 825,557.51	**$ 2.4830**
Retail Transmission Connection Service Rate	2012 Demand kW Billed / Unbilled	May 1, 2013 Rate	Total Calculated Charges	**Harmonized Rate RTSR-Connection**
General Service 50 to 4,999 kW - Non - Interval Metered	91,666	$ 1.7325	$ 158,811.35	
General Service 50 to 4,999 kW - Interval Metered	240,823	$ 1.9149	461,151.96	
	332,489		$ 619,963.31	**$ 1.8646**

The Board has provided a Microsoft Excel workbook "2014_RTSR_Adjustment_Work_Form" for distributors to complete as part of their 2014 electricity rate applications. HCHI has completed two versions of this workbook to determine the RTSRs as part of this Application. One model is completed for all of HCHI's customer rate classes excluding the Embedded Distributor – HONI rate class, and the second model completed solely for the Embedded Distributor – HONI rate class. HCHI tracks all RSVA accounts applicable to the Embedded Distributor - HONI separately, (i.e. billed, unbilled, and charged amounts), in order to separately track any variances related to the Embedded Distributor - HONI. The deferral and variance

account disposition calculations have also been completed in a separate model for the Embedded Distributor - HONI from all other customer rate classes as further detailed in Exhibit 9. The General Service 50 to 4,999 kW harmonized 2013 rate was used in the regular customer rate class model in order to calculate the proposed 2014 RTSRs. HCHI has filed both models in Excel format and included PDF copies as Appendix A and Appendix B to this Exhibit.

Table 9 below combines the details of the proposed RTSRs reproduced from both models from sheet "13. Final 2014 RTS Rates". This table also details the RTSR revenues included in HCHI's cost of power calculations that are consistent with HCHI's working capital allowance calculation.

Table 9
Proposed Retail Transmission Service Rates

	Proposed RTSR Network		Proposed RTSR Connection	
Customer Class	**Rate**	**Revenue**	**Rate**	**Revenue**
Residential	$ 0.0065	$ 1,171,355	$ 0.0049	$ 883,021
General Service Less Than 50 kW	$ 0.0058	$ 333,502	$ 0.0045	$ 258,752
General Service 50 to 4,999 kW	$ 2.4800	$ 848,964	$ 1.9031	$ 651,477
Street Lighting	$ 1.7912	$ 11,908	$ 1.3671	$ 9,088
Sentinel Lighting	$ 1.8003	$ 1,637	$ 1.3957	$ 1,269
Unmetered Scattered Load	$ 0.0058	$ 2,166	$ 0.0045	$ 1,681
Embedded Distributor - Hydro One Networks Inc.	$ 2.8960	$ 678,455	$ 2.3898	$ 559,866

HCHI further requests that when the UTRs are updated in January 2014, HCHI be allowed to update its RTSR model calculations which will further impact the working capital allowance and Revenue Requirement calculations, requiring further adjustment to these applied-for distribution rates. HCHI also requests that if HONI updates its RTSRs in January 2014, that it be allowed to update all applicable models and rates accordingly.

Retail Service Charges

Retail services refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity as set out in the Retail Settlement Code.

The Board has established variance accounts, including 1518 RCVA Retail and 1548 RCVA STR, to record the difference between charges rendered to retailers, and the direct incremental costs for providing the retail services.

HCHI is not proposing any changes to the current retail rates and charges. Current approved retail rates and charges as approved in HCHI's 2013 IRM3 Rate Application (EB-2012-0129) can be found on the current Tariff of Rates and Charges in Appendix C to this Exhibit.

Wholesale Market Service Rate

The Wholesale Market Service ("WMS") rate is designed to allow distributors to recover costs charged by the IESO for the operation of the IESO-administered markets and the operation of the IESO-controlled grid. The Board has determined that this rate should be consistent across the province and that changes to this rate would normally be made on a generic basis. On March 21, 2013, the Board issued a Decision with Reasons and Rate Order (EB-2013-0067) establishing that the WMS rate to be used by distributors to bill their customers be $0.0044 / kWh effective May 1, 2013. The Board also approved the Rural and Remote Rate Protection ("RRRP") rate to be $0.0012 / kWh.

In accordance with the Filing Requirements, HCHI has reflected a total charge of $0.0056 / kWh in its Application. This is consistent with HCHI's working capital allowance calculations detailed in Exhibit 2.

Smart Metering Entity Charge

The Board issued a Decision and Order (EB-2012-0100/EB-2012-0211) on March 28, 2013, establishing a Smart Metering Entity Charge of $0.79 per month for the Residential and General Service Less Than 50 kW customer classes effective May 1, 2013.

In accordance with the Filing Requirements, HCHI has reflected this Smart Metering Entity Charge of $0.79 in its Application. This is consistent with HCHI's working capital allowance calculations detailed in Exhibit 2.

Specific Service Charges

HCHI is not proposing any change to the current specific service charges or any new specific service charges. HCHI does not have any rates and charges reflected in its Conditions of Service. Current approved specific service charges as approved in HCHI's 2013 IRM3 Rate Application (EB-2012-0129) can be found on the current Tariff of Rates and Charges in Appendix C to this Exhibit.

Table 10 details the revenue recovered from these rates and charges for 2010, 2011, and 2012 Actual, the 2013 Bridge Year and 2014 Test Year. This revenue corresponds to the revenue detailed in Exhibit 3 for specific service charges.

Table 10
Specific Service Charge Revenue

Specific Service Charge	2010 Actual	2011 Actual	2012 Actual	2013 Bridge	2014 Test
Occupancy Charges	$ 74,730	$ 76,290	$ 81,660	$ 78,000	$ 78,000
Reconnection Charges	55,960	23,180	26,640	25,395	25,395
NSF Charges	4,935	3,915	3,600	3,600	3,600
microFIT Monthly Service Charge	622	6,144	10,665	13,864	13,992
Total	**$ 136,247**	**$ 109,529**	**$ 122,565**	**$ 120,859**	**$ 120,987**

Low Voltage Service Rates

Low voltage transactions are not part of the electricity wholesale market but rather are specific charges between HONI, as the host distributor, and the Local Distribution Company ("LDC")for shared low voltage lines and distribution stations. Low voltage ("LV") charges are paid to HONI and recovered from the LDC's customers. As discussed in Exhibit 1, Tab 5, Schedule 6, HCHI is embedded to HONI.

In order to allocate the LV charges appropriately across the customer rate classes, HCHI has calculated the proportion of retail transmission connection revenue collected from each class. The amount of LV costs forecast in 2014 is based on calculations shown in Table 11 below. These calculations are based on applying the appropriate HONI sub-transmission charges that were effective January 1, 2013 to the forecast units for 2014. The forecast units for 2014 are based on the actual demand kW for the period January to July of 2013 and August to December of 2012.

Table 11
Forecasted Low Voltage Cost for 2014 Test Year

		Billing Determinant		
HONI Sub-Transmission ("ST") Charge Types	**HONI 2013 ST Rates**	**Demand (kW)**	**Months**	**Low Voltage Dollars**
Monthly Service Charge (6 Points)	$ 295.68		72	$ 21,289
Meter Charge (2 DS's)	$ 471.17		24	$ 11,308
Low Voltage Charges - LVDS	$ 1.965	23,293		$ 45,771
Common ST Lines - TS	$ 0.675	60,780		$ 41,027
Volumetric Rate Riders	$ 0.285	60,780		$ 17,322
Adjustment for Long-term Load Transfers				$ 590
Total Low Voltage Costs to be Allocated				**$ 137,307**

Similar to the request in the RTSR section, HCHI also requests that if HONI updates its sub-transmission rates in January 2014, HCHI be allowed to update all applicable models and rates accordingly.

In Table 12 below, HCHI has provided the historical HONI LV charges, the revenues collected from HCHI's customers, and the calculated variance.

Table 12
Low Voltage Variance Analysis

	2010 Actual	2011 Actual	2012 Actual	2013 Bridge	2014 Test
HONI Low Voltage Charges	$ 111,192	$ 105,480	$ 114,257	$ 144,570	$ 137,307
Customer Revenue (Billed & Unbilled)	(191,013)	(136,552)	(135,035)	(136,201)	(137,307)
Variance	$ (79,821)	$ (31,073)	$ (20,779)	$ 8,369	$ -

The negative variance in 2010 is gradually moving towards a positive variance as forecast in the 2013 Bridge Year. This is on account of the HONI sub-transmission rates gradually increasing over time with no increase to HCHI's low voltage rates charged to its customers. The 2014 Test Year is forecast to have a zero balance to account for the proposed increase to HCHI's LV rates.

Table 13 below provides the allocation of the LV charges to each customer rate class.

Table 13
Low Voltage Charges Allocated by Customer Class

Customer Class	Retail Transmission Connection		Basis for Allocation	Allocation Percentage	Allocated $
	per kWh	per kW			
Residential	0.0048		$ 811,217	49.07%	$ 67,376
General Service Less Than 50 kW	0.0044		237,271	14.35%	$ 19,704
General Service 50 to 4,999 kW		1.7325	593,076	35.87%	$ 49,252
Street Lighting		1.3395	8,905	0.54%	$ 741
Sentinel Lighting		1.3675	1,243	0.08%	$ 110
Unmetered Scattered Load	0.0044		1,541	0.09%	$ 124
TOTALS			**$1,653,253**	**100.00%**	**137,307**

HCHI has calculated the variable LV component to be shown separate on the 2014 Tariff of Rates and Charges based on the allocation in the above Table 13 and 2014 Test Year usage. The following Table 14 summarizes the variable charge, the Low Voltage Cost Rate Adder, required to recover the forecasted LV charges.

Table 14
Variable Charge to Recover Low Voltage Charges

Customer Class	LV Adjustment Allocated	Calculated kWh	Calculated kW	Billing Determinant	LV Rate / kWh	LV Rate / kW
Residential	$ 67,376	169,003,519		kWh	0.0004	
General Service Less Than 50 kW	19,704	53,925,141		kWh	0.0004	
General Service 50 to 4,999 kW	49,252	121,879,907	342,324	kW		0.1439
Street Lighting	741	327,143	6,648	kW		0.1115
Sentinel Lighting	110	2,387,575	909	kW		0.1210
Unmetered Scattered Load	124	350,238		kWh	0.0004	
TOTALS	**$ 137,307**	**347,873,523**	**349,881**			

DETERMINATION OF LOSS ADJUSTMENT FACTORS

Total Loss Factor

The total loss factor ("TLF") to be applied to customer's consumption based on the average wholesale and retail kWh for the five years 2008 to 2012 was calculated in Appendix 2-R "Loss Factors" filed separately as part of this Application. The following Table 15 details this same five year average calculation. In HCHI's 2010 COS rate application, HCHI engaged Kinectrics Inc. to perform a Distribution Loss Assessment "Kinectrics Report" K-418006-001-GE-0001". The Kinectrics Report calculated HCHI's current approved loss factor of 1.0680, which was the five year average for the years 2004 to 2008, in the same manner as the current Appendix 2-R. This loss factor is calculated for HCHI's entire customer base excluding the Embedded Distributor - HONI which will be calculated separately and discussed later in this Exhibit.

Table 15
Total Loss Factor Calculations

		Historical Years					5-Year Average
		2008	2009	2010	2011	2012	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	376,481,614	357,880,923	371,940,959	374,153,148	368,113,993	369,714,127
A(2)	"Wholesale" kWh delivered to distributor (lower value)	374,608,571	356,100,421	370,090,506	372,291,690	366,282,580	367,874,754
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)						-
C	Net "Wholesale" kWh delivered to distributor = A(2) - B	374,608,571	356,100,421	370,090,506	372,291,690	366,282,580	367,874,754
D	"Retail" kWh delivered by distributor	352,084,247	338,528,029	348,418,005	349,960,100	344,598,404	346,717,757
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)						-
F	Net "Retail" kWh delivered by distributor = D - E	352,084,247	338,528,029	348,418,005	349,960,100	344,598,404	346,717,757
G	Loss Factor in Distributor's system = C / F	1.0640	1.0519	1.0622	1.0638	1.0629	1.0610
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0050	1.0050	1.0050	1.0050	1.0050	1.0050
	Total Losses						
I	Total Loss Factor = G x H	1.0693	1.0572	1.0675	1.0691	1.0682	1.0663

HCHI is proposing an updated total loss factor of 1.0663 for its entire customer base, excluding the Embedded Distributor – HONI.

Supply Facilities Loss Factor

The supply facilities loss factor (SFLF) calculation as shown in Table 16 below has also been updated using the methodology from the Kinectrics Report filed as Appendix B in HCHI's 2010 COS rate application and represents the losses on supply to HCHI. The SFLF is calculated in accordance with the Board's "*Filing Requirements for Electricity Distribution Rate Applications*" dated July 17, 2013 Appendix 2-R "Loss Factors", item H based upon the weighted average (i.e. using kWh for the full year 2012) of the standard SFLF on each feeder. The resulting weighted average SFLF of 1.0050 is used in the calculations for the total loss factor above in Table 15.

Table 16
Supply Facilities Loss Factor Calculations

	Jarvis TS				
2012	57M1	57M3	57M4	57M5	57M6
kWh	1.0045	1.0060	1.0045	1.0045	1.0045
Sub-Total	26,939,327	47,709,096	60,563,158	15,589,313	31,118,550
Loss	121,227	286,255	272,534	70,152	140,033

Dunnville TS		Caledonia TS				
31M1	31M2	27M3	27M4	27M5	27M6	
1.0045	1.0060	1.0060	1.0045	1.0045	1.0060	Total
95,858,831	5,548,212	61,398,971	65,397,992	52,545,146	34,966,671	497,635,266
431,365	33,289	368,394	294,291	236,453	209,800	2,463,793
				Weighted Average SFLF		**1.0050**

Embedded Distributor – Hydro One Networks Inc. ("HONI") Loss Factor

In total, as detailed in Exhibit 1, HONI is embedded to HCHI at 8 supply points.

Effective March 8, 2009 seven (7) wholesale supply points to HONI were de-registered with the IESO and became retail points of supply from HCHI to HONI. Originally there were eight (8) supply points that were converted from wholesale to retail points of

supply at the request of HONI. Their stated intent was to avoid the requirement to replace the Primary Metering Units ("PMUs") at these locations in order to make them IESO compliant. The 8 points were reduced to 7 points in conjunction with the sale of certain lines from HONI to HCHI and the associated separation work (EB-2009-0136) that was completed that had the effect of eliminating the Argyle PMU and adding its load to the Green's Road PMU. This had little or no effect on the approved TLF of 1.0305 and the Kinectrics Report was not revised to reflect this change.

The 8th point became embedded to HCHI on April 24, 2009. Air Products Canada Ltd. ("Air Products") is a large customer of HONI, which is physically located in Haldimand County, and needed additional capacity to accommodate an expansion. It was agreed that the most cost effective method for supplying this load was for HONI to connect it to the existing 57M1 feeder which is owned by HCHI.

In HCHI's 2010 COS rate application, an Embedded Distributor and Site Specific Loss Factor report was prepared by Kinectrics Inc. on behalf of HCHI to calculate individual TLFs for each of these 8 supply points as well as a single TLF of 1.0305 for the group based upon the weighted average. The Kinectrics Report "K-418006-002-GE-0001" filed as Appendix C in Exhibit 8 of the 2010 COS rate application has now been updated by HCHI. The updated calculation is for the period 2009 to 2012 inclusive and calculates a weighted average based on this same four year period for an updated TLF of 1.0288 specific to the Embedded Distributor - HONI. The calculations were updated based on the following assumptions:

1. Annual hours were modified to reflect the change in hours for a leap year (8,784 used in 2012 for a leap year and 8,760 hours for non-leap years);
2. Argyle PMU was eliminated in March 2009 and therefore its loading for 3 months was transferred to the Greens Road PMU;
3. Non-technical losses and the SFLF remained constant; and

4. Individual line section calculations remained constant except for updated annual kWh and peak amps for each major load as in the Kinectric's Report prepared for the 2010 COS rate application.

Table 17 provides the details for each year and Table 18 provides the weighted average summary of 2009 to 2012 with the proposed TLF. The 2009 information for the 8th supply point, Air Products, is only a partial year from the date that they became an embedded point on April 24, 2009. Information was available for the entire 2009 period for the other 7 supply points as they were previously deduction points from HCHI's totalization tables with the IESO prior to becoming embedded to HCHI.

Table 17
Embedded Distributor – Hydro One Loss Factor Calculations

2009 Year								
Customer	Technical Losses	Non-Technical Losses	Distribution Loss Factor	Supply Facilities Factor	Total Loss Factor	Annual Energy kWh	Fraction of Group	Contribution to Weighted Average TLF
Canadian Gypsum	0.017	0.012	1.029	1.006	1.036	37,417,198	0.216	0.224
5th Line PMU	0.006	0.012	1.018	1.006	1.024	2,806,706	0.016	0.017
3rd Line PMU	0.020	0.012	1.032	1.006	1.039	9,207,847	0.053	0.055
4th Line PMU	0.020	0.012	1.032	1.006	1.038	2,584,752	0.015	0.016
6 Line PMU	0.025	0.012	1.037	1.006	1.043	2,562,936	0.015	0.015
Georgia Pacific	0.009	0.012	1.021	1.006	1.027	11,221,116	0.065	0.067
Greens Road PMU	0.018	0.012	1.030	1.006	1.036	4,679,513	0.027	0.028
Air Products	0.007	0.012	1.019	1.0045	1.025	102,439,483	0.592	0.607
SUM			**1.0274**			**172,919,551**		**1.0292**
2010 Year								
Customer	Technical Losses	Non-Technical Losses	Distribution Loss Factor	Supply Facilities Factor	Total Loss Factor	Annual Energy kWh	Fraction of Group	Contribution to Weighted Average TLF
Canadian Gypsum	0.010	0.012	1.022	1.006	1.028	38,512,067	0.456	0.469
5th Line PMU	0.004	0.012	1.016	1.006	1.022	2,956,339	0.035	0.036
3rd Line PMU	0.012	0.012	1.024	1.006	1.030	9,728,398	0.115	0.119
4th Line PMU	0.012	0.012	1.024	1.006	1.030	2,575,626	0.031	0.031
6 Line PMU	0.015	0.012	1.027	1.006	1.033	2,964,353	0.035	0.036
Georgia Pacific	0.004	0.012	1.016	1.006	1.023	11,533,192	0.137	0.140
Greens Road PMU	0.006	0.012	1.018	1.006	1.024	5,517,254	0.065	0.067
Air Products	0.016	0.012	1.028	1.0045	1.035	10,582,254	0.125	0.130
SUM			**1.022**			**84,369,482**		**1.0281**

2011 Year								
Customer	Technical Losses	Non-Technical Losses	Distribution Loss Factor	Supply Facilities Factor	Total Loss Factor	Annual Energy kWh	Fraction of Group	Contribution to Weighted Average TLF
Canadian Gypsum	0.010	0.012	1.022	1.006	1.028	39,034,312	0.467	0.480
5th Line PMU	0.004	0.012	1.016	1.006	1.022	3,105,480	0.037	0.038
3rd Line PMU	0.012	0.012	1.024	1.006	1.030	9,992,060	0.119	0.123
4th Line PMU	0.011	0.012	1.023	1.006	1.029	2,754,455	0.033	0.034
6 Line PMU	0.014	0.012	1.026	1.006	1.032	3,081,731	0.037	0.038
Georgia Pacific	0.005	0.012	1.017	1.006	1.023	10,911,279	0.130	0.134
Greens Road PMU	0.007	0.012	1.019	1.006	1.025	5,312,936	0.064	0.065
Air Products	0.019	0.012	1.031	1.0045	1.037	9,437,121	0.113	0.117
SUM			**1.022**			**83,629,373**		**1.0283**
2012 Year								
Customer	Technical Losses	Non-Technical Losses	Distribution Loss Factor	Supply Facilities Factor	Total Loss Factor	Annual Energy kWh	Fraction of Group	Contribution to Weighted Average TLF
Canadian Gypsum	0.009	0.012	1.021	1.006	1.027	38,704,975	0.479	0.492
5th Line PMU	0.003	0.012	1.015	1.006	1.021	2,896,192	0.036	0.037
3rd Line PMU	0.011	0.012	1.023	1.006	1.029	9,644,479	0.119	0.123
4th Line PMU	0.011	0.012	1.023	1.006	1.029	2,854,320	0.035	0.036
6TH Line PMU	0.013	0.012	1.025	1.006	1.031	3,360,137	0.042	0.043
Georgia Pacific	0.016	0.012	1.028	1.006	1.034	9,258,514	0.115	0.118
Greens Road PMU	0.027	0.012	1.039	1.006	1.045	5,113,312	0.063	0.066
Air Products	0.012	0.012	1.024	1.0045	1.030	9,011,713	0.111	0.115
SUM			**1.025**			**80,843,642**		**1.0294**

Table 18
Embedded Distributor – HONI Total Loss Factor

Year	Annual Energy kWh Total per Year	Distribution Loss Factor	Contribution to Weighted Average TLF
2009	172,919,551	1.0274	1.0292
2010	84,369,482	1.0219	1.0281
2011	83,629,373	1.0221	1.0283
2012	80,843,642	1.0246	1.0294
Average		1.0240	**1.0288**

Haldimand County Hydro is proposing a TLF of 1.0288 for the Embedded Distributor – HONI.

Statement as to Whether the Applicant is Embedded

Although HCHI uses HONI-owned lines to supply its customers at 4 feeder locations - Caledonia TS 27M3, Caledonia TS 27M6, Dunnville TS 31M2, and Jarvis TS 57M3 – HCHI owns the PMUs at the TS' in all 4 instances as its load occurs upstream of the HONI load. Consequently, HCHI is not considered as embedded to HONI and in fact is updating retail rates and total loss factors in this Application for HONI embedded to HCHI for these same feeders.

Materiality Analysis on Distribution Losses

Haldimand County Hydro's 2014 Test Year proposed Distribution Loss Factor ("DLF") is 1.0610 as compared to 1.0624 approved in its 2010 COS rate application.

One source of higher losses at HCHI was demonstrated in the Kinectrics Report No. K-418006-002-GE-0001 at section 3.2 as filed with the 2010 COS rate application and is still applicable today where they calculate losses at two HONI wholesale points – Springvale PMU and Wainfleet PMU. The updated calculation is for the period 2009 to 2012 and calculates a weighted average based on this same four year period for an updated TLF for these two supply points of 1.0570 as compared to the weighted average calculated in 2009 of 1.0474.

Table 19 below provides the details for each year and Table 20 provides the weighted average summary of 2009 to 2012 with the proposed TLF.

Table 19
TLF Calculations for Springvale PMU and Wainfleet PMU

2009 Year								
Customer	Technical Losses	Non-Technical Losses	Distribution Loss Factor	Supply Facilities Factor	Total Loss Factor	Annual Energy kWh	Fraction of Group	Contribution to Weighted Average TLF
Springvale PMU	0.057	0.012	1.069	1.006	1.076	36,746,786	0.563	0.606
Wainfleet PMU	0.013	0.012	1.025	1.006	1.031	28,528,901	0.437	0.451
SUM			1.047			65,275,687		1.0563
2010 Year								
Customer	Technical Losses	Non-Technical Losses	Distribution Loss Factor	Supply Facilities Factor	Total Loss Factor	Annual Energy kWh	Fraction of Group	Contribution to Weighted Average TLF
Springvale PMU	0.055	0.012	1.067	1.006	1.073	39,450,818	0.581	0.623
Wainfleet PMU	0.013	0.012	1.025	1.006	1.031	28,501,576	0.419	0.432
SUM			1.046			67,952,394		1.0557
2011 Year								
Customer	Technical Losses	Non-Technical Losses	Distribution Loss Factor	Supply Facilities Factor	Total Loss Factor	Annual Energy kWh	Fraction of Group	Contribution to Weighted Average TLF
Springvale PMU	0.056	0.012	1.068	1.006	1.074	39,622,999	0.670	0.719
Wainfleet PMU	0.019	0.012	1.031	1.006	1.037	19,558,411	0.330	0.343
SUM			1.049			59,181,410		1.0620
2012 Year								
Customer	Technical Losses	Non-Technical Losses	Distribution Loss Factor	Supply Facilities Factor	Total Loss Factor	Annual Energy kWh	Fraction of Group	Contribution to Weighted Average TLF
Springvale PMU	0.052	0.012	1.064	1.006	1.070	39,426,408	0.586	0.627
Wainfleet PMU	0.013	0.012	1.025	1.006	1.031	27,893,308	0.414	0.427
SUM			1.045			67,319,716		1.0542

Table 20
TLF for Springvale PMU and Wainfleet PMU

Year	Annual Energy kWh Total per Year	Distribution Loss Factors	Contribution to Weighted Average TLF
2009	65,275,687	1.0472	1.0563
2010	67,952,394	1.0460	1.0557
2011	59,181,410	1.0494	1.0620
2012	67,319,716	1.0446	1.0542
Average		1.0468	**1.0570**

The site-specific TLF calculated for these two supply points collectively is 1.0570 as shown in Table 20 above. However, in accordance with the Board's "*Filing Requirements for Electricity Distribution Rate Applications*" dated July 17, 2013 Appendix 2-R "Loss Factors", item H the average HONI TLF of 1.0340 is applied to each of these wholesale supply points, essentially causing higher losses for HCHI than if the site specific TLF was applied.

HCHI takes losses seriously and considers losses as part of the planning and preparation of capital expenditure projects. As noted in Kinectrics Report no. K-418006-001-GE-0001 (refer to Distribution System Plan Appendix L) *"Loss levels of 5% are considered to be an OEB threshold. However, this 5% loss level may never be achievable for certain utilities. HCHI is one of Ontario's largest utilities by area at 1,252 km^2 with only 13.26 customers per km of line."* (Note: also as calculated in HCHI's 2014 Cost Allocation model on sheet "E1 Categorization") *In fact, rural utilities similar to HCHI often experience much higher losses – in the order of 7% to 8% total Technical + Non-Technical losses".* HCHI will continue to use the recommendations and conclusions of the Kinectrics Report prepared in conjunction with its 2010 COS rate application, which discusses in detail Technical and Non-Technical losses. Reducing losses remains an objective at HCHI as part of ensuring that its distribution system is efficient and cost effective.

Technical Losses

Techniques for reducing technical losses are described in detail in the Kinectrics Report prepared in conjunction with HCHI's 2010 COS rate application and in further detail in HCHI's Distribution System Plan contained as part of Exhibit 2 with this Application. The main techniques are capacitor placement, load balancing on phases, transformer sizing, and conductor sizing.

HCHI continues to have several initiatives in place which have had, and will continue to have, the effect of reducing its distribution losses including:

- An aggressive tree trimming program which has the effect of reducing losses due to contact with trees as well as improving reliability.
- All new construction is built to 27.6/16 kV design standards even if the line will initially continue to be operated at 4.16/2.4 kV or 8.3/4.8 kV in preparation for ultimately converting all lines to 27.6/16 kV. This includes the purchase of dual voltage distribution transformers. Actual conversion of lines to the higher 27.6/16 kV occurs when effective to do so from a cost and reliability perspective.
- Consistent with converting lines for operation at 27.6/16 kV, the elimination of distribution substations is part of the initiative and 5 such substations have been eliminated over the past 8 years. The elimination of a substation removes one significant source of losses from the system.
- Wire size is considered by the Engineering Department in designing all projects to ensure line losses are minimized.
- Losses are taken into account when purchasing new transformers and when sizing transformers for new or replacement installations.
- Regular monitoring of feeders occurs to identify imbalances so corrective action may be taken.

The Kinectrics Report also describes two methodologies to calculate technical energy losses - 1. “Top-Down” (this is the method HCHI currently uses) and 2. “Bottom-up” (a method based on modeling losses in individual components).

HCHI has purchased and installed CYME Distribution Analysis software and has integrated this software with its GIS system in an effort to determine losses using the ‘bottom up’ approach. A new Distribution Engineer position was added and staffed in 2012 to run the software, model the system for use in various CYME modules and conduct the analysis for purposes of better coordinated protection schemes, balanced phases, and identification of areas of voltage concerns and losses.

Another ‘bottom up’ approach to reducing technical energy losses is the harvesting and use of the valuable interval (hourly) data from smart meters. HCHI has installed interval meters at its distribution stations and will be using this data in conjunction with smart meter data using subtractive totalization calculations using the Operational Data Store (“ODS”) software.

HCHI also has plans to pilot temporary 16 kV measuring data loggers (including volts, amps, and kWh) for the purposes of targeting long single phase (or 3 phase) branch circuits and perform subtractive totalization calculations using smart meter data to identify specific areas for both loss types. These temporary or portable 16 kV measuring data loggers can also be used for theft detection in areas where illegal connections to the primary conductors of the distribution system is suspected.

HCHI expects to start conducting these “bottom up” studies in depth in 2014.

<u>Non – Technical losses</u>

HCHI continues to have an active plan to mitigate the impact of losses due to metering and billing multiplier errors by inspection and cross-phase testing its greater than 50 kW meter installations once a year and testing all other transformer rated meter installations once every three years.

The availability of tamper, power outage and restoration alarms from smart meters are also used to determine if meters are removed by unauthorized people for the purposes of tampering or installing by-passes in meter bases.

A bottom up approach to evaluating line losses will occur in 2014 as Advance Metering Infrastructure ("AMI") data and the installation of more feeder metering points will allow for subtractive totalization in specific areas to determine excessive line loss areas.

Effect of Distributed Generation on Losses

The REG Plan has identified a total of 33.9 MW of renewable generation that is connected to HCHI's distribution system. HCHI does not know the impact that these distributed generators have on total distribution losses. HCHI is interested in learning more on what the industry has studied on this topic to date. HCHI has found two papers that discuss this topic as follows:

1) A paper that was presented to the IEEE in 2007 authored by Fracisco M. Gonzalez – Longatt titled "*Impact of Distributed Generation over Power Losses on Distribution System*". The paper suggested that:

   "*Distributed generation may have a significant impact on the system and equipment operation in terms of steady-state operation, dynamic operation, reliability, power quality, stability and safety for both customers and electricity suppliers. This impact may manifest itself either positively or negatively, depending on the distribution system, distributed generator and load characteristics…"*

2) A paper presented in World Academy of Science Engineering and Technology 64 2012 "*Technical and economic impacts of Distributed Generation on Distribution Systems*" indicates on page 290 that:

   "*The impact of DG units on energy losses will depend on the specific characteristics of the network, such as demand distribution and*

behavior, topology, as well as the relative location of the generators and whether their output is firm or variable. Incorporating these complexities into an optimization framework for energy loss minimization is a challenge that has only been (partially) addressed by a few studies."

RATE MITIGATION

HCHI submits that the total bill impacts of its proposed 2014 electricity distribution rates for all customer rate classes except for Sentinel Lighting are under 10% and therefore do not require rate mitigation.

HCHI has adjusted the revenue-to-cost ratio for the Sentinel Lighting customer rate class in order to be within the Board's target range and to maintain revenue neutrality, consistent with the approach approved by the Board in other cost of service applications since 2008. It is HCHI's understanding that in order to address the under recovery of cost in this class, a change to the revenue-to-cost has occurred in many other cases and the bill impacts for this class have been higher than 10%. HCHI is proposing to mitigate the Sentinel Lighting rate increase by adjusting its revenue-to-cost ratio to bring the class to the bottom of the Board's target range over two rate years; that is 2014 and 2015 as discussed in Exhibit 7 – Cost Allocation at Tab 1, Schedule 4. The offsetting revenue decrease is being applied to the General Service 50 to 4,999 kW rate class over this same two year period.

EXISTING RATE CLASSES AND RATE SCHEDULE

HCHI's existing customer rate classes as defined in the tariff of rates and charges effective May 1, 2013 are as follows:

Residential

This classification applies to a customer's main place of abode and may include additional buildings served through the same meter, provided they are not rental income units. Residential includes Urban, Suburban, and Farm customer's premises which can be occupied on a year-round and seasonal basis. Farm applies to properties actively engaged in agricultural production as defined by Statistics Canada. These premises must be supplied from a single phase primary line. The farm definition does not include tree, sod, or pet farms. Services to year-round pumping stations or other ancillary services remote from the main farm shall be classed as farm. Further servicing details are available in the distributor's Conditions of Service.

General Service Less Than 50 kW

General Service does include farms supplied from polyphase primary lines. General Service includes commercial, industrial, educational, administrative, auxiliary, and government services. It also includes combination services where a variety of users are made of the service by the owner of one property. This classification applies to a non-residential account 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.

General Service 50 to 4,999 kW

General Service does include farms supplied from polyphase primary lines. General Service includes commercial, industrial, educational, administrative, auxiliary, and government services. It also includes combination services where a variety of users are

made of the service by the owner of one property. This classification applies to a non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

Unmetered Scattered Load

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, 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.

Sentinel Lighting

This classification refers to an account that is an unmetered lighting load supplied to a sentinel light. (Metered sentinel lighting is captured under the consumption of the principal service.) The consumption for these customers is assumed to have the same hourly consumption load profile as for Street Lighting. Further servicing details are available in the distributor's Conditions of Service.

Street Lighting

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street

lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

Embedded Distributor – Hydro One Networks Inc.

This classification applies to Hydro One Networks Inc., an electricity distributor licensed by the Board, and provided electricity by means of Haldimand County Hydro Inc.'s distribution facilities. Further servicing details are available in the distributor's Conditions of Service.

microFIT

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.

HCHI's current rate schedule has been attached to this Exhibit as Appendix C Haldimand County Hydro Inc.'s Board Approved Tariff of Rates and Charges for May 1, 2013 Rates (EB-2012-0129).

PROPOSED RATE CLASSES AND RATE SCHEDULE

HCHI is not requesting any changes to its existing customer rate classes.

HCHI's proposed Tariff of Rates and Charges for rates effective May 1, 2014 has been included as Appendix D.

A "track changes" version of the current tariff showing the proposed changes from the current tariff to the proposed 2014 tariff is provided as Appendix E.

Appendix 2-Z "Tariff" has also been filed as part of this Application.

RECONCILIATION OF RATE CLASS REVENUE

In accordance with the Filing Requirements, HCHI has provided a reconciliation of customer rate class distribution revenue. Table 21 provides revenue per customer rate class calculations under the current approved rates effective May 1, 2013. Table 22 provides the revenue per customer rate class calculations under the 2014 proposed rates and the total Base Revenue Requirement.

Table 21
Revenue per Customer Rate Class under Current May 1, 2013 Rates

Rate Class	Customers/ Connections	Number of Customers/Connections			Test Year Consumption		Current Rates			Revenues at Current Rates	Transformer Allowance Credit	Revenue Excluding Transformer Allowance
		Start of Test Year	End of Test Year	Average	kWh	kW	Monthly Service Charge	Volumetric Charge				
								kWh	kW			
Residential	Customers	18,772	18,772	18,772	169,003,519		$ 18.17	$ 0.0265		$ 8,571,640		$ 8,571,640
General Service Less Than 50 kW	Customers	2,363	2,363	2,363	53,925,141		$ 29.04	$ 0.0205		$ 1,928,924		$ 1,928,924
General Service 50 to 4,999 kW	Customers	153	153	153	121,879,907	342,324	$ 104.06		$ 4.8286	$ 1,844,000	$ 92,302	$ 1,751,698
Street Lighting	Connections	2,979	2,979	2,979	2,387,575	6,648	$ 6.09		$ 15.5853	$ 321,316		$ 321,316
Sentinel Lighting	Connections	502	502	502	327,143	909	$ 12.99		$ 33.5294	$ 108,730		$ 108,730
Unmetered Scattered Load	Connections	68	68	68	350,238		$ 20.83	$ 0.0027		$ 17,943		$ 17,943
Embedded Distributor - Hydro One Networks Inc.	Customers	8	8	8	72,629,941	227,715	$ 184.32		$ 0.5680	$ 147,037		$ 147,037
Total		24,845	24,845		420,503,464	577,596				$ 12,939,590	$ 92,302	**$ 12,847,288**

Table 22
Revenue per Customer Rate Class under 2014 Test Year Proposed Rates

Rate Class	Customers/ Connections	Number of Customers/Connections			Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Class Specific Revenue Requirement	Transformer Allowance Credit	Revenue Excluding Transformer Allowance
		Start of Test Year	End of Test Year	Average	kWh	kW	Monthly Service Charge	Volumetric Charge					
								kWh	kW				
Residential	Customers	18,772	18,772	18,772	169,003,519		$ 18.85	$ 0.0275		$ 8,893,823	$ 8,892,831		$ 8,892,831
General Service Less Than 50 kW	Customers	2,363	2,363	2,363	53,925,141		$ 25.77	$ 0.0182		$ 1,712,172	$ 1,711,607		$ 1,711,607
General Service 50 to 4,999 kW	Customers	153	153	153	121,879,907	342,324	$ 84.98		$ 3.9926	$ 1,522,786	$ 1,522,785	$ 92,302	$ 1,430,483
Street Lighting	Connections	2,979	2,979	2,979	2,387,575	6,648	$ 6.10		$ 15.6168	$ 321,883	$ 321,966		$ 321,966
Sentinel Lighting	Connections	502	502	502	327,143	909	$ 14.14		$ 36.4943	$ 118,352	$ 118,345		$ 118,345
Unmetered Scattered Load	Connections	68	68	68	350,238		$ 20.87	$ 0.0027		$ 17,976	$ 17,974		$ 17,974
Embedded Distributor	Customers	8	8	8	72,629,941	227,715	$ 478.04		$ 1.4731		$ 381,346		
- Hydro One Networks Inc.										$ 381,339			$ 381,346
Total		24,845	24,845		420,503,464	577,596				$ 12,968,331	$ 12,966,854	$ 92,302	**$ 12,874,552**

HCHI's revenue at its proposed rates of $12,874,552, excluding transformer ownership allowance credit, versus HCHI's revenue at existing rates of $12,847,288, excluding transformer ownership allowance credit, results in a revenue deficiency of $27,264 as detailed in Exhibit 6 of this Application.

HCHI has provided reconciliation in Table 23 below between the 2014 distribution rate calculations based on the 2014 proposed rates (shown in Table 22 above) and the total Base Revenue Requirement. Table 24 further reconciles the total Revenue Requirement by including the reconciliation by customer rate class revenue (Base Revenue Requirement) and the Other Operating Revenue (Revenue Offsets).

The Base Revenue Requirement reconciliation has also been included in Appendix 2-V "Revenue Reconciliation" as part of this Application.

Table 23
2014 Test Year Distribution Revenue Reconciliation

Customer Class	Fixed Distribution Revenue	Variable Distribution Revenue	Transformer Ownerhsip Allowance Credit	Total Distribution Revenue (excluding Transformer Ownership Allowance)
Residential	$ 4,246,419	$ 4,646,412	$ -	$ 8,892,831
General Service Less Than 50 kW	730,686	980,921	-	$ 1,711,607
General Service Less 50 to 4,999 kW	156,020	1,366,765	(92,302)	$ 1,430,483
Street Lighting	218,145	103,821	-	$ 321,966
Sentinel Lighting	85,171	33,174	-	$ 118,345
Unmetered Scattered Load	17,027	947	-	$ 17,974
Embedded Distributor - Hydro One Networks Inc.	45,892	335,454	-	$ 381,346
Total Base Revenue Requirement	**$ 5,499,360**	**$ 7,467,494**	**$ (92,302)**	**$ 12,874,552**

Table 24
2014 Test Year Total Revenue Requirement Reconciliation

Base Revenue Requirement		**$ 12,874,552**
Other Revenue:		
Late Payment Charges (4225)	$ 310,717	
Specific Service Charges:		
Miscellaneous Service Revenues (4235)	$ 120,987	
Other Operating Revenue:		
SSS Administration Revenue (4086)	$ 68,148	
Retail Services Revenue (4082)	26,720	
STR Revenue (4084)	1,010	
Rent from Electric Property (4210)	76,226	
	$ 172,104	
Other Income and Deductions:		
Revenues from Merchandising, Jobbing, Etc. (4325)	$ 16,873	
Gain on Disposition of Property (4355)	13,940	
Revenues from Non-Utility Operations (4375)	374,205	
Miscellaneous Non-Operating Income (4390)	90,585	
Interest and Dividend Income (4405)	38,650	
	$ 534,253	
Miscellaneous Revenue Offsets		**$ 1,138,061**
Total Revenue Requirement		**$ 14,012,613**

RATE AND BILL IMPACTS

Appendix F to this Schedule presents the total bill impacts by customer rate class.

Total bill impacts are derived using the applicable May 1, 2013 and the proposed May 1, 2014 distribution rates, the proposed Deferral and Variance Account rate rider, the proposed Property, Plant, & Equipment Change Adjustment (account 1576) rate rider, the proposed new utility-specific Renewable Energy Generation Investment funding adder, the proposed Stranded Meter rate rider, the proposed Low Voltage cost rate adder, the proposed Retail Transmission Service rates, and the proposed revised Total Loss Factors. Electricity rates have been applied to all rate classes based on the published Regulated Price Plan ("RPP") commodity prices effective May 1, 2013, either using time-of-use ("TOU") or non-TOU (RPP Tiers 1 and 2).

The total bill impacts are calculated for each customer rate class at various levels of consumption. The rate impacts are assessed on the basis of moving to the proposed distribution rates and have been presented in the bill impact calculations as provided by the Board in the updated Filing Requirements as Appendix 2-W "Bill Impacts".



v 4.0

RTSR Workform for Electricity Distributors (2014 Filers)

Utility Name	Haldimand County Hydro Inc.
Service Territory	
Assigned EB Number	EB-2013-0134
Name and Title	Jacqueline A. Scott, Finance Manager
Phone Number	905-765-5211 ext. 2237
Email Address	jscott@hchydro.ca
Date	11/15/13
Last COS Re-based Year	**2010**

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

This Workbook Model is protected by copyright and is being made available to you solely for the purpose of filing your COS/IRM application. You may use and copy this model for that purpose, and provide a copy of this model to any person that is advising or assisting you in that regard. Except as indicated above, any copying, reproduction, publication, sale, adaptation, translation, modification, reverse engineering or other use or dissemination of this model without the express written consent of the Ontario Energy Board is prohibited. If you provide a copy of this model to a person that is advising or assisting you in preparing the application or reviewing your draft rate order, you must ensure that the person understands and agrees to the restrictions noted above.

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 (2014 Filers)

1. Info
2. Table of Contents
3. Rate Classes
4. RRR Data
5. UTRs and Sub-Transmission
6. Historical Wholesale
7. Current Wholesale
8. Forecast Wholesale
9. Adj Network to Current WS
10. Adj Conn. to Current WS
11. Adj Network to Forecast WS
12. Adj Conn. to Forecast WS
13. Final 2013 RTS Rates



RTSR Workform for Electricity Distributors (2014 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	kWh	$ 0.0065	$ 0.0048
General Service Less Than 50 kW	kWh	$ 0.0058	$ 0.0044
General Service 50 to 4,999 kW	kW	$ 2.4830	$ 1.8646
Unmetered Scattered Load	kWh	$ 0.0058	$ 0.0044
Sentinel Lighting	kW	$ 1.8025	$ 1.3675
Street Lighting	kW	$ 1.7934	$ 1.3395
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			
Choose Rate Class			



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	kWh	168,308,353		1.0680		179,753,321	-
General Service Less Than 50 kW	kWh	56,019,870		1.0680		59,829,221	-
General Service 50 to 4,999 kW	kW	117,120,197	332,490		48.28%	117,120,197	332,490
Unmetered Scattered Load	kWh	389,982		1.0680		416,501	-
Sentinel Lighting	kW	361,875	1,003		49.45%	361,875	1,003
Street Lighting	kW	2,398,127	6,665		49.32%	2,398,127	6,665



RTSR Workform for Electricity Distributors (2014 Filers)

Uniform Transmission Rates	Unit	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 3.57	$ 3.63	$ 3.63
Line Connection Service Rate	kW	$ 0.80	$ 0.75	$ 0.75
Transformation Connection Service Rate	kW	$ 1.86	$ 1.85	$ 1.85

Hydro One Sub-Transmission Rates	Unit	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 2.65	$ 3.18	$ 3.18
Line Connection Service Rate	kW	$ 0.64	$ 0.70	$ 0.70
Transformation Connection Service Rate	kW	$ 1.50	$ 1.63	$ 1.63
Both Line and Transformation Connection Service Rate	kW	$ 2.14	$ 2.33	$ 2.33

If needed , add extra host here (I)	Unit	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW			
Line Connection Service Rate	kW			
Transformation Connection Service Rate	kW			
Both Line and Transformation Connection Service Rate	kW	$ -	$ -	$ -

If needed , add extra host here (II)	Unit	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW			
Line Connection Service Rate	kW			
Transformation Connection Service Rate	kW			
Both Line and Transformation Connection Service Rate	kW	$ -	$ -	$ -

Hydro One Sub-Transmission Rate Rider 9A	Unit	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Rate Description		**Rate**	**Rate**	**Rate**
RSVA Transmission network – 4714 – which affects 1584	kW	**$ -**	**$ 0.1465**	**$ 0.1465**
RSVA Transmission connection – 4716 – which affects 1586	kW	**$ -**	**$ 0.0667**	**$ 0.0667**
RSVA LV – 4750 – which affects 1550	kW	**$ -**	**$ 0.0475**	**$ 0.0475**
RARA 1 – 2252 – which affects 1590	kW	**$ -**	**$ 0.0419**	**$ 0.0419**
RARA 1 – 2252 – which affects 1590 (2008)	kW	**$ -**	**-$ 0.0270**	**-$ 0.0270**
RARA 1 – 2252 – which affects 1590 (2009)	kW	**$ -**	**-$ 0.0006**	**-$ 0.0006**
Hydro One Sub-Transmission Rate Rider 9A	kW	**$ -**	**$ 0.2750**	**$ 0.2750**

		Historical 2012	Current 2013	Forecast 2014
Transformer Allowance Credit (if applicable, enter as a negative value)	$			



RTSR Workform for Electricity Distributors (2014 Filers)

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants 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	53,210	$3.57	$ 189,960	55,877	$0.80	$ 44,701	55,877	$1.86	$ 103,931	$ 148,632
February	45,742	$3.57	$ 163,298	51,602	$0.80	$ 41,282	51,602	$1.86	$ 95,980	$ 137,261
March	45,654	$3.57	$ 162,985	50,760	$0.80	$ 40,608	50,760	$1.86	$ 94,413	$ 135,021
April	30,427	$3.57	$ 108,627	41,904	$0.80	$ 33,524	41,904	$1.86	$ 77,942	$ 111,466
May	35,256	$3.57	$ 125,863	41,609	$0.80	$ 33,287	41,609	$1.86	$ 77,393	$ 110,680
June	53,468	$3.57	$ 190,882	57,399	$0.80	$ 45,919	57,399	$1.86	$ 106,762	$ 152,680
July	66,616	$3.57	$ 237,818	61,677	$0.80	$ 49,341	61,677	$1.86	$ 114,719	$ 164,060
August	62,437	$3.57	$ 222,901	62,792	$0.80	$ 50,234	62,792	$1.86	$ 116,794	$ 167,027
September	58,705	$3.57	$ 209,577	55,336	$0.80	$ 44,269	55,336	$1.86	$ 102,926	$ 147,195
October	39,092	$3.57	$ 139,558	44,955	$0.80	$ 35,964	44,955	$1.86	$ 83,616	$ 119,580
November	50,173	$3.57	$ 179,117	52,561	$0.80	$ 42,048	52,561	$1.86	$ 97,763	$ 139,811
December	50,276	$3.57	$ 179,484	54,906	$0.80	$ 43,925	54,906	$1.86	$ 102,125	$ 146,049
Total	591,055	$ 3.57	$ 2,110,068	631,377	$ 0.80	$ 505,102	631,377	$ 1.86	$ 1,174,362	$ 1,679,464

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	2,699	$2.65	$ 7,153	2,675	$0.64	$ 1,712	2,675	$1.50	$ 4,012	$ 5,724
February	2,160	$2.65	$ 5,723	1,866	$0.64	$ 1,194	1,866	$1.50	$ 2,799	$ 3,994
March	4,264	$2.65	$ 11,300	4,212	$0.64	$ 2,695	4,212	$1.50	$ 6,317	$ 9,013
April	8,712	$2.65	$ 23,086	8,734	$0.64	$ 5,590	8,734	$1.50	$ 13,101	$ 18,691
May	3,477	$2.65	$ 9,213	3,479	$0.64	$ 2,226	3,479	$1.50	$ 5,218	$ 7,445
June	5,507	$2.65	$ 14,594	5,552	$0.64	$ 3,553	5,552	$1.50	$ 8,327	$ 11,881
July	10,068	$2.65	$ 26,682	10,139	$0.64	$ 6,489	10,139	$1.50	$ 15,208	$ 21,697
August	2,456	$2.65	$ 6,509	2,634	$0.64	$ 1,686	2,634	$1.50	$ 3,951	$ 5,636
September	866	$2.65	$ 2,295	1,912	$0.64	$ 1,223	1,912	$1.50	$ 2,867	$ 4,091
October	9,385	$2.65	$ 24,871	9,461	$0.64	$ 6,055	9,461	$1.50	$ 14,192	$ 20,247
November	5,242	$2.65	$ 13,890	5,279	$0.64	$ 3,379	5,279	$1.50	$ 7,919	$ 11,298
December	7,928	$3.07	$ 24,376	7,838	$0.69	$ 5,397	7,838	$1.61	$ 12,583	$ 17,980
Total	62,764	$ 2.70	$ 169,693	63,779	$ 0.65	$ 41,200	63,779	$ 1.51	$ 96,495	$ 137,695

Add Extra Host Here (I) (if needed)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		$ -
August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -



RTSR Workform for Electricity Distributors (2014 Filers)

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants 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.

Add Extra Host Here (II) (if needed)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		$ -
August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	55,909	$3.53	$ 197,113	58,551	$0.79	$ 46,413	58,551	$1.84	$ 107,943	$ 154,356
February	47,901	$3.53	$ 169,021	53,468	$0.79	$ 42,476	53,468	$1.85	$ 98,779	$ 141,255
March	49,918	$3.49	$ 174,285	54,972	$0.79	$ 43,303	54,972	$1.83	$ 100,731	$ 144,034
April	39,139	$3.37	$ 131,712	50,638	$0.77	$ 39,113	50,638	$1.80	$ 91,043	$ 130,157
May	38,733	$3.49	$ 135,077	45,088	$0.79	$ 35,514	45,088	$1.83	$ 82,611	$ 118,125
June	58,975	$3.48	$ 205,476	62,950	$0.79	$ 49,472	62,950	$1.83	$ 115,089	$ 164,561
July	76,684	$3.45	$ 264,500	71,815	$0.78	$ 55,830	71,815	$1.81	$ 129,927	$ 185,757
August	64,893	$3.54	$ 229,410	65,426	$0.79	$ 51,919	65,426	$1.85	$ 120,744	$ 172,664
September	59,571	$3.56	$ 211,871	57,248	$0.79	$ 45,492	57,248	$1.85	$ 105,793	$ 151,285
October	48,477	$3.39	$ 164,430	54,416	$0.77	$ 42,019	54,416	$1.80	$ 97,808	$ 139,827
November	55,415	$3.48	$ 193,007	57,840	$0.79	$ 45,427	57,840	$1.83	$ 105,682	$ 151,109
December	58,204	$3.50	$ 203,860	62,743	$0.79	$ 49,322	62,743	$1.83	$ 114,707	$ 164,029
Total	653,820	$ 3.49	$ 2,279,761	695,157	$ 0.79	$ 546,302	695,157	$ 1.83	$ 1,270,857	$ 1,817,159



RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to calculate the expected billing when current 2013 Uniform Transmission Rates are applied against historical 2012 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	53,210	$ 3.6300	$ 193,153	55,877	$ 0.7500	$ 41,908	55,877	$ 1.8500	$ 103,372	$ 145,280
February	45,742	$ 3.6300	$ 166,042	51,602	$ 0.7500	$ 38,702	51,602	$ 1.8500	$ 95,464	$ 134,165
March	45,654	$ 3.6300	$ 165,724	50,760	$ 0.7500	$ 38,070	50,760	$ 1.8500	$ 93,906	$ 131,976
April	30,427	$ 3.6300	$ 110,452	41,904	$ 0.7500	$ 31,428	41,904	$ 1.8500	$ 77,523	$ 108,952
May	35,256	$ 3.6300	$ 127,979	41,609	$ 0.7500	$ 31,207	41,609	$ 1.8500	$ 76,977	$ 108,184
June	53,468	$ 3.6300	$ 194,090	57,399	$ 0.7500	$ 43,049	57,399	$ 1.8500	$ 106,188	$ 149,237
July	66,616	$ 3.6300	$ 241,815	61,677	$ 0.7500	$ 46,258	61,677	$ 1.8500	$ 114,102	$ 160,360
August	62,437	$ 3.6300	$ 226,647	62,792	$ 0.7500	$ 47,094	62,792	$ 1.8500	$ 116,166	$ 163,260
September	58,705	$ 3.6300	$ 213,099	55,336	$ 0.7500	$ 41,502	55,336	$ 1.8500	$ 102,372	$ 143,874
October	39,092	$ 3.6300	$ 141,904	44,955	$ 0.7500	$ 33,716	44,955	$ 1.8500	$ 83,167	$ 116,883
November	50,173	$ 3.6300	$ 182,128	52,561	$ 0.7500	$ 39,420	52,561	$ 1.8500	$ 97,237	$ 136,657
December	50,276	$ 3.6300	$ 182,501	54,906	$ 0.7500	$ 41,179	54,906	$ 1.8500	$ 101,575	$ 142,755
Total	591,055	$ 3.63	$ 2,145,531	631,377	$ 0.75	$ 473,533	631,377	$ 1.85	$ 1,168,048	$ 1,641,581

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	2,699	$ 3.3265	$ 8,979	2,675	$ 0.7667	$ 2,051	2,675	$ 1.6300	$ 4,359	$ 6,410
February	2,160	$ 3.3265	$ 7,185	1,866	$ 0.7667	$ 1,431	1,866	$ 1.6300	$ 3,042	$ 4,473
March	4,264	$ 3.3265	$ 14,184	4,212	$ 0.7667	$ 3,229	4,212	$ 1.6300	$ 6,865	$ 10,094
April	8,712	$ 3.3265	$ 28,979	8,734	$ 0.7667	$ 6,696	8,734	$ 1.6300	$ 14,236	$ 20,933
May	3,477	$ 3.3265	$ 11,565	3,479	$ 0.7667	$ 2,667	3,479	$ 1.6300	$ 5,671	$ 8,338
June	5,507	$ 3.3265	$ 18,320	5,552	$ 0.7667	$ 4,256	5,552	$ 1.6300	$ 9,049	$ 13,306
July	10,068	$ 3.3265	$ 33,493	10,139	$ 0.7667	$ 7,773	10,139	$ 1.6300	$ 16,526	$ 24,299
August	2,456	$ 3.3265	$ 8,171	2,634	$ 0.7667	$ 2,019	2,634	$ 1.6300	$ 4,293	$ 6,313
September	866	$ 3.3265	$ 2,880	1,912	$ 0.7667	$ 1,466	1,912	$ 1.6300	$ 3,116	$ 4,581
October	9,385	$ 3.3265	$ 31,220	9,461	$ 0.7667	$ 7,254	9,461	$ 1.6300	$ 15,422	$ 22,676
November	5,242	$ 3.3265	$ 17,437	5,279	$ 0.7667	$ 4,048	5,279	$ 1.6300	$ 8,605	$ 12,653
December	7,928	$ 3.3265	$ 26,373	7,838	$ 0.7667	$ 6,009	7,838	$ 1.6300	$ 12,776	$ 18,785
Total	62,764	$ 3.33	$ 208,785	63,779	$ 0.77	$ 48,900	63,779	$ 1.63	$ 103,960	$ 152,860

Add Extra Host Here (I)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -



RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to calculate the expected billing when current 2013 Uniform Transmission Rates are applied against historical 2012 transmission units.

Add Extra Host Here (II)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	55,909	$3.62	$ 202,132	58,551	$0.75	$ 43,958	58,551	$1.84	$ 107,732	$ 151,690
February	47,901	$3.62	$ 173,227	53,468	$0.75	$ 40,132	53,468	$1.84	$ 98,506	$ 138,638
March	49,918	$3.60	$ 179,908	54,972	$0.75	$ 41,299	54,972	$1.83	$ 100,771	$ 142,070
April	39,139	$3.56	$ 139,431	50,638	$0.75	$ 38,125	50,638	$1.81	$ 91,760	$ 129,884
May	38,733	$3.60	$ 139,544	45,088	$0.75	$ 33,874	45,088	$1.83	$ 82,647	$ 116,521
June	58,975	$3.60	$ 212,409	62,950	$0.75	$ 47,305	62,950	$1.83	$ 115,237	$ 162,542
July	76,684	$3.59	$ 275,308	71,815	$0.75	$ 54,031	71,815	$1.82	$ 130,628	$ 184,659
August	64,893	$3.62	$ 234,818	65,426	$0.75	$ 49,114	65,426	$1.84	$ 120,459	$ 169,572
September	59,571	$3.63	$ 215,979	57,248	$0.75	$ 42,968	57,248	$1.84	$ 105,488	$ 148,456
October	48,477	$3.57	$ 173,124	54,416	$0.75	$ 40,970	54,416	$1.81	$ 98,589	$ 139,559
November	55,415	$3.60	$ 199,564	57,840	$0.75	$ 43,468	57,840	$1.83	$ 105,842	$ 149,310
December	58,204	$3.59	$ 208,874	62,743	$0.75	$ 47,188	62,743	$1.82	$ 114,351	$ 161,539
Total	653,820	$ 3.60	$ 2,354,316	695,157	$ 0.75	$ 522,433	695,157	$ 1.83	$ 1,272,009	$ 1,794,441



RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to calculate the expected billing when forecasted 2014 Uniform Transmission Rates are applied against historical 2012 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	53,210	$ 3.6300	$ 193,153	55,877	$ 0.7500	$ 41,908	55,877	$ 1.8500	$ 103,372	$ 145,280
February	45,742	$ 3.6300	$ 166,042	51,602	$ 0.7500	$ 38,702	51,602	$ 1.8500	$ 95,464	$ 134,165
March	45,654	$ 3.6300	$ 165,724	50,760	$ 0.7500	$ 38,070	50,760	$ 1.8500	$ 93,906	$ 131,976
April	30,427	$ 3.6300	$ 110,452	41,904	$ 0.7500	$ 31,428	41,904	$ 1.8500	$ 77,523	$ 108,952
May	35,256	$ 3.6300	$ 127,979	41,609	$ 0.7500	$ 31,207	41,609	$ 1.8500	$ 76,977	$ 108,184
June	53,468	$ 3.6300	$ 194,090	57,399	$ 0.7500	$ 43,049	57,399	$ 1.8500	$ 106,188	$ 149,237
July	66,616	$ 3.6300	$ 241,815	61,677	$ 0.7500	$ 46,258	61,677	$ 1.8500	$ 114,102	$ 160,360
August	62,437	$ 3.6300	$ 226,647	62,792	$ 0.7500	$ 47,094	62,792	$ 1.8500	$ 116,166	$ 163,260
September	58,705	$ 3.6300	$ 213,099	55,336	$ 0.7500	$ 41,502	55,336	$ 1.8500	$ 102,372	$ 143,874
October	39,092	$ 3.6300	$ 141,904	44,955	$ 0.7500	$ 33,716	44,955	$ 1.8500	$ 83,167	$ 116,883
November	50,173	$ 3.6300	$ 182,128	52,561	$ 0.7500	$ 39,420	52,561	$ 1.8500	$ 97,237	$ 136,657
December	50,276	$ 3.6300	$ 182,501	54,906	$ 0.7500	$ 41,179	54,906	$ 1.8500	$ 101,575	$ 142,755
Total	591,055	$ 3.63	$ 2,145,531	631,377	$ 0.75	$ 473,533	631,377	$ 1.85	$ 1,168,048	$ 1,641,581

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	2,699	$ 3.3265	$ 8,979	2,675	$ 0.7667	$ 2,051	2,675	$ 1.6300	$ 4,359	$ 6,410
February	2,160	$ 3.3265	$ 7,185	1,866	$ 0.7667	$ 1,431	1,866	$ 1.6300	$ 3,042	$ 4,473
March	4,264	$ 3.3265	$ 14,184	4,212	$ 0.7667	$ 3,229	4,212	$ 1.6300	$ 6,865	$ 10,094
April	8,712	$ 3.3265	$ 28,979	8,734	$ 0.7667	$ 6,696	8,734	$ 1.6300	$ 14,236	$ 20,933
May	3,477	$ 3.3265	$ 11,565	3,479	$ 0.7667	$ 2,667	3,479	$ 1.6300	$ 5,671	$ 8,338
June	5,507	$ 3.3265	$ 18,320	5,552	$ 0.7667	$ 4,256	5,552	$ 1.6300	$ 9,049	$ 13,306
July	10,068	$ 3.3265	$ 33,493	10,139	$ 0.7667	$ 7,773	10,139	$ 1.6300	$ 16,526	$ 24,299
August	2,456	$ 3.3265	$ 8,171	2,634	$ 0.7667	$ 2,019	2,634	$ 1.6300	$ 4,293	$ 6,313
September	866	$ 3.3265	$ 2,880	1,912	$ 0.7667	$ 1,466	1,912	$ 1.6300	$ 3,116	$ 4,581
October	9,385	$ 3.3265	$ 31,220	9,461	$ 0.7667	$ 7,254	9,461	$ 1.6300	$ 15,422	$ 22,676
November	5,242	$ 3.3265	$ 17,437	5,279	$ 0.7667	$ 4,048	5,279	$ 1.6300	$ 8,605	$ 12,653
December	7,928	$ 3.3265	$ 26,373	7,838	$ 0.7667	$ 6,009	7,838	$ 1.6300	$ 12,776	$ 18,785
Total	62,764	$ 3.33	$ 208,785	63,779	$ 0.77	$ 48,900	63,779	$ 1.63	$ 103,960	$ 152,860

Add Extra Host Here (I)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -



RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to calculate the expected billing when forecasted 2014 Uniform Transmission Rates are applied against historical 2012 transmission units.

Add Extra Host Here (II)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	55,909	$ 3.62	$ 202,132	58,551	$ 0.75	$ 43,958	58,551	$ 1.84	$ 107,732	$ 151,690
February	47,901	$ 3.62	$ 173,227	53,468	$ 0.75	$ 40,132	53,468	$ 1.84	$ 98,506	$ 138,638
March	49,918	$ 3.60	$ 179,908	54,972	$ 0.75	$ 41,299	54,972	$ 1.83	$ 100,771	$ 142,070
April	39,139	$ 3.56	$ 139,431	50,638	$ 0.75	$ 38,125	50,638	$ 1.81	$ 91,760	$ 129,884
May	38,733	$ 3.60	$ 139,544	45,088	$ 0.75	$ 33,874	45,088	$ 1.83	$ 82,647	$ 116,521
June	58,975	$ 3.60	$ 212,409	62,950	$ 0.75	$ 47,305	62,950	$ 1.83	$ 115,237	$ 162,542
July	76,684	$ 3.59	$ 275,308	71,815	$ 0.75	$ 54,031	71,815	$ 1.82	$ 130,628	$ 184,659
August	64,893	$ 3.62	$ 234,818	65,426	$ 0.75	$ 49,114	65,426	$ 1.84	$ 120,459	$ 169,572
September	59,571	$ 3.63	$ 215,979	57,248	$ 0.75	$ 42,968	57,248	$ 1.84	$ 105,488	$ 148,456
October	48,477	$ 3.57	$ 173,124	54,416	$ 0.75	$ 40,970	54,416	$ 1.81	$ 98,589	$ 139,559
November	55,415	$ 3.60	$ 199,564	57,840	$ 0.75	$ 43,468	57,840	$ 1.83	$ 105,842	$ 149,310
December	58,204	$ 3.59	$ 208,874	62,743	$ 0.75	$ 47,188	62,743	$ 1.82	$ 114,351	$ 161,539
Total	653,820	$ 3.60	$ 2,354,316	695,157	$ 0.75	$ 522,433	695,157	$ 1.83	$ 1,272,009	$ 1,794,441



RTSR Workform for Electricity Distributors (2014 Filers)

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

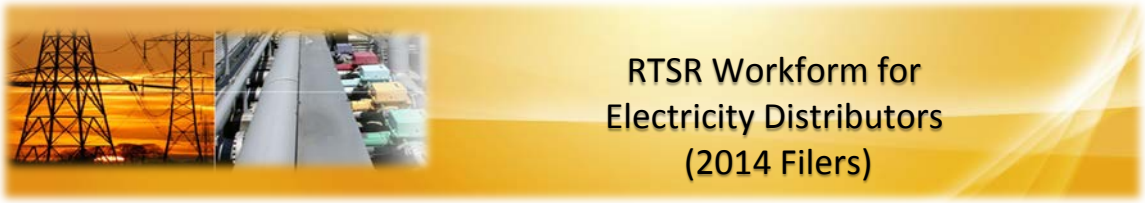
Rate Class	Unit	Current RTSR-Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR Network
Residential	kWh	$ 0.0065	179,753,321	-	$ 1,168,397	49.6%	$ 1,166,989	$0.0065
General Service Less Than 50 kW	kWh	$ 0.0058	59,829,221	-	$ 347,009	14.7%	$ 346,592	$0.0058
General Service 50 to 4,999 kW	kW	$ 2.4830	117,120,197	332,490	$ 825,573	35.0%	$ 824,578	$2.4800
Unmetered Scattered Load	kWh	$ 0.0058	416,501	-	$ 2,416	0.1%	$ 2,413	$0.0058
Sentinel Lighting	kW	$ 1.8025	361,875	1,003	$ 1,808	0.1%	$ 1,806	$1.8003
Street Lighting	kW	$ 1.7934	2,398,127	6,665	$ 11,953	0.5%	$ 11,939	$1.7912
					$ 2,357,155			



RTSR Workform for Electricity Distributors (2014 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	kWh	$ 0.0048	179,753,321	-	$ 862,816	49.1%	$ 880,622	$0.0049
General Service Less Than 50 kW	kWh	$ 0.0044	59,829,221	-	$ 263,249	15.0%	$ 268,681	$0.0045
General Service 50 to 4,999 kW	kW	$ 1.8646	117,120,197	332,490	$ 619,961	35.3%	$ 632,755	$1.9031
Unmetered Scattered Load	kWh	$ 0.0044	416,501	-	$ 1,833	0.1%	$ 1,870	$0.0045
Sentinel Lighting	kW	$ 1.3675	361,875	1,003	$ 1,372	0.1%	$ 1,400	$1.3957
Street Lighting	kW	$ 1.3395	2,398,127	6,665	$ 8,928	0.5%	$ 9,112	$1.3671
					$ 1,758,157			



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	kWh	$0.0065	179,753,321	-	1,166,989.40	49.6%	$ 1,166,989	$0.0065
General Service Less Than 50 kW	kWh	$0.0058	59,829,221	-	$ 346,592	14.7%	$ 346,592	$0.0058
General Service 50 to 4,999 kW	kW	$2.4800	117,120,197	332,490	$ 824,578	35.0%	$ 824,578	$2.4800
Unmetered Scattered Load	kWh	$0.0058	416,501	-	$ 2,413	0.1%	$ 2,413	$0.0058
Sentinel Lighting	kW	$1.8003	361,875	1,003	$ 1,806	0.1%	$ 1,806	$1.8003
Street Lighting	kW	$1.7912	2,398,127	6,665	$ 11,939	0.5%	$ 11,939	$1.7912
					$ 2,354,316			



RTSR Workform for Electricity Distributors (2014 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	kWh	$ 0.0049	179,753,321	-	$ 880,622	49.1%	$ 880,622	$ 0.0049
General Service Less Than 50 kW	kWh	$ 0.0045	59,829,221	-	$ 268,681	15.0%	$ 268,681	$ 0.0045
General Service 50 to 4,999 kW	kW	$ 1.9031	117,120,197	332,490	$ 632,755	35.3%	$ 632,755	$ 1.9031
Unmetered Scattered Load	kWh	$ 0.0045	416,501	-	$ 1,870	0.1%	$ 1,870	$ 0.0045
Sentinel Lighting	kW	$ 1.3957	361,875	1,003	$ 1,400	0.1%	$ 1,400	$ 1.3957
Street Lighting	kW	$ 1.3671	2,398,127	6,665	$ 9,112	0.5%	$ 9,112	$ 1.3671
					$ 1,794,441			



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 descriptions for the RTSRs are transfered automatically from Sheet 4 to Sheet 11, Column A.

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Residential	kWh	$ 0.0065	$ 0.0049
General Service Less Than 50 kW	kWh	$ 0.0058	$ 0.0045
General Service 50 to 4,999 kW	kW	$ 2.4800	$ 1.9031
Unmetered Scattered Load	kWh	$ 0.0058	$ 0.0045
Sentinel Lighting	kW	$ 1.8003	$ 1.3957
Street Lighting	kW	$ 1.7912	$ 1.3671



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RTSR Workform for Electricity Distributors (2014 Filers)

Utility Name	Haldimand County Hydro Inc.
Service Territory	
Assigned EB Number	EB-2013-0134
Name and Title	Jacqueline A. Scott, Finance Manager
Phone Number	905-765-5211 ext. 2237
Email Address	jscott@hchydro.ca
Date	15-Nov-13
Last COS Re-based Year	**2010**

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

This Workbook Model is protected by copyright and is being made available to you solely for the purpose of filing your COS/IRM application. You may use and copy this model for that purpose, and provide a copy of this model to any person that is advising or assisting you in that regard. Except as indicated above, any copying, reproduction, publication, sale, adaptation, translation, modification, reverse engineering or other use or dissemination of this model without the express written consent of the Ontario Energy Board is prohibited. If you provide a copy of this model to a person that is advising or assisting you in preparing the application or reviewing your draft rate order, you must ensure that the person understands and agrees to the restrictions noted above.

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 (2014 Filers)

1. Info
2. Table of Contents
3. Rate Classes
4. RRR Data
5. UTRs and Sub-Transmission
6. Historical Wholesale
7. Current Wholesale
8. Forecast Wholesale
9. Adj Network to Current WS
10. Adj Conn. to Current WS
11. Adj Network to Forecast WS
12. Adj Conn. to Forecast WS
13. Final 2013 RTS Rates



RTSR Workform for Electricity Distributors (2014 Filers)

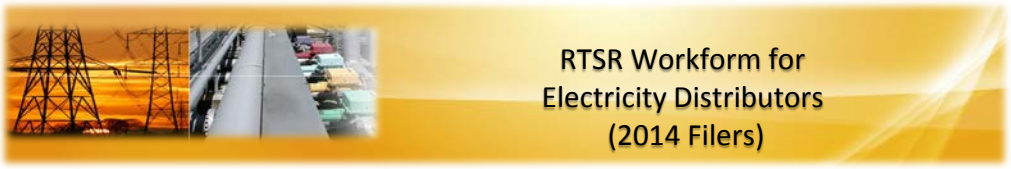
1. **Select the appropriate rate classes that appear on your most recent Board-Approved Tariff of Rates and Charges.**
2. **Enter the RTS Network and Connection Rate as it appears on the Tariff of Rates and Charges**

Rate Class	Unit	RTSR-Network	RTSR-Connection
Embedded Distributor	**kW**	**$ 2.5638**	**$ 2.3365**
Choose Rate Class			
Choose Rate Class			
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Choose Rate Class			
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Choose Rate Class			
Choose Rate Class			



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
Embedded Distributor	**kW**	71,831,928	245,804	1.0305	**40.05%**	74,022,802	253,301



Uniform Transmission Rates	Unit	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 3.57	$ 3.63	$ 3.63
Line Connection Service Rate	kW	$ 0.80	$ 0.75	$ 0.75
Transformation Connection Service Rate	kW	$ 1.86	$ 1.85	$ 1.85

Hydro One Sub-Transmission Rates	Unit	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 2.65	$ 3.18	$ 3.18
Line Connection Service Rate	kW	$ 0.64	$ 0.70	$ 0.70
Transformation Connection Service Rate	kW	$ 1.50	$ 1.63	$ 1.63
Both Line and Transformation Connection Service Rate	kW	$ 2.14	$ 2.33	$ 2.33

If needed , add extra host here (I)	Unit	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW			
Line Connection Service Rate	kW			
Transformation Connection Service Rate	kW			
Both Line and Transformation Connection Service Rate	kW	$ -	$ -	$ -

If needed , add extra host here (II)	Unit	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW			
Line Connection Service Rate	kW			
Transformation Connection Service Rate	kW			
Both Line and Transformation Connection Service Rate	kW	$ -	$ -	$ -

Hydro One Sub-Transmission Rate Rider 9A	Unit	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Rate Description		**Rate**	**Rate**	**Rate**
RSVA Transmission network – 4714 – which affects 1584	kW	$ -	$ 0.1465	$ 0.1465
RSVA Transmission connection – 4716 – which affects 1586	kW	$ -	$ 0.0667	$ 0.0667
RSVA LV – 4750 – which affects 1550	kW	$ -	$ 0.0475	$ 0.0475
RARA 1 – 2252 – which affects 1590	kW	$ -	$ 0.0419	$ 0.0419
RARA 1 – 2252 – which affects 1590 (2008)	kW	$ -	-$ 0.0270	-$ 0.0270
RARA 1 – 2252 – which affects 1590 (2009)	kW	$ -	-$ 0.0006	-$ 0.0006
Hydro One Sub-Transmission Rate Rider 9A	kW	$ -	$ 0.2750	$ 0.2750

		Historical 2012	Current 2013	Forecast 2014
Transformer Allowance Credit (if applicable, enter as a negative value)	$			



In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants 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	492	$3.57	$ 1,756	538	$0.80	$ 431	538	$1.86	$ 1,001	$ 1,432
February	480	$3.57	$ 1,715	516	$0.80	$ 413	516	$1.86	$ 960	$ 1,373
March	446	$3.57	$ 1,592	460	$0.80	$ 368	460	$1.86	$ 856	$ 1,224
April	1,950	$3.57	$ 6,962	1,950	$0.80	$ 1,560	1,950	$1.86	$ 3,627	$ 5,188
May	7,751	$3.57	$ 27,672	8,975	$0.80	$ 7,180	8,975	$1.86	$ 16,694	$ 23,874
June	9,068	$3.57	$ 32,372	9,424	$0.80	$ 7,539	9,424	$1.86	$ 17,529	$ 25,069
July	412	$3.57	$ 1,472	9,230	$0.80	$ 7,384	9,230	$1.86	$ 17,168	$ 24,552
August	413	$3.57	$ 1,474	9,546	$0.80	$ 7,637	9,546	$1.86	$ 17,755	$ 25,392
September	410	$3.57	$ 1,464	9,305	$0.80	$ 7,444	9,305	$1.86	$ 17,307	$ 24,751
October	9,603	$3.57	$ 34,283	9,603	$0.80	$ 7,682	9,603	$1.86	$ 17,862	$ 25,544
November	483	$3.57	$ 1,725	505	$0.80	$ 404	505	$1.86	$ 940	$ 1,345
December	440	$3.57	$ 1,572	509	$0.80	$ 407	509	$1.86	$ 947	$ 1,355
Total	31,949	$ 3.57	$ 114,059	60,562	$ 0.80	$ 48,450	60,562	$ 1.86	$ 112,646	$ 161,096

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	16,288	$2.65	$ 43,163	16,331	$0.64	$ 10,452	16,331	$1.50	$ 24,497	$ 34,949
February	16,056	$2.65	$ 42,549	16,377	$0.64	$ 10,481	16,377	$1.50	$ 24,565	$ 35,046
March	15,236	$2.65	$ 40,375	15,368	$0.64	$ 9,836	15,368	$1.50	$ 23,053	$ 32,888
April	15,003	$2.65	$ 39,759	15,172	$0.64	$ 9,710	15,172	$1.50	$ 22,758	$ 32,468
May	15,457	$2.65	$ 40,962	15,505	$0.64	$ 9,923	15,505	$1.50	$ 23,258	$ 33,181
June	15,698	$2.65	$ 41,599	15,711	$0.64	$ 10,055	15,711	$1.50	$ 23,567	$ 33,622
July	15,953	$2.65	$ 42,274	15,982	$0.64	$ 10,229	15,982	$1.50	$ 23,974	$ 34,202
August	15,523	$2.65	$ 41,135	15,639	$0.64	$ 10,009	15,639	$1.50	$ 23,459	$ 33,468
September	15,215	$2.65	$ 40,320	15,408	$0.64	$ 9,861	15,408	$1.50	$ 23,113	$ 32,974
October	14,574	$2.65	$ 38,620	14,610	$0.64	$ 9,350	14,610	$1.50	$ 21,915	$ 31,265
November	15,291	$2.65	$ 40,522	15,310	$0.64	$ 9,798	15,310	$1.50	$ 22,965	$ 32,763
December	15,361	$2.65	$ 40,706	15,453	$0.64	$ 9,890	15,453	$1.50	$ 23,180	$ 33,070
Total	185,655	$ 2.65	$ 491,984	186,868	$ 0.64	$ 119,595	186,868	$ 1.50	$ 280,301	$ 399,897

Add Extra Host Here (I) (if needed)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		$ -
August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (II) (if needed)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		$ -
August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -



RTSR Workform for Electricity Distributors (2014 Filers)

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants 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.

Total	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	16,780	$2.68	$ 44,919	16,870	$0.65	$ 10,883	16,870	$1.51	$ 25,498	$ 36,381
February	16,537	$2.68	$ 44,264	16,893	$0.64	$ 10,894	16,893	$1.51	$ 25,525	$ 36,419
March	15,682	$2.68	$ 41,967	15,828	$0.64	$ 10,204	15,828	$1.51	$ 23,908	$ 34,112
April	16,954	$2.76	$ 46,721	17,122	$0.66	$ 11,270	17,122	$1.54	$ 26,386	$ 37,656
May	23,209	$2.96	$ 68,634	24,480	$0.70	$ 17,103	24,480	$1.63	$ 39,951	$ 57,055
June	24,766	$2.99	$ 73,971	25,136	$0.70	$ 17,595	25,136	$1.63	$ 41,096	$ 58,691
July	16,365	$2.67	$ 43,746	25,213	$0.70	$ 17,613	25,213	$1.63	$ 41,142	$ 58,755
August	15,936	$2.67	$ 42,609	25,185	$0.70	$ 17,646	25,185	$1.64	$ 41,214	$ 58,859
September	15,625	$2.67	$ 41,784	24,713	$0.70	$ 17,305	24,713	$1.64	$ 40,419	$ 57,725
October	24,177	$3.02	$ 72,903	24,213	$0.70	$ 17,033	24,213	$1.64	$ 39,776	$ 56,809
November	15,774	$2.68	$ 42,247	15,815	$0.65	$ 10,203	15,815	$1.51	$ 23,905	$ 34,107
December	15,801	$2.68	$ 42,278	15,963	$0.65	$ 10,298	15,963	$1.51	$ 24,127	$ 34,425
Total	217,604	$ 2.79	$ 606,043	247,430	$ 0.68	$ 168,045	247,430	$ 1.59	$ 392,948	$ 560,993



RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to calculate the expected billing when current 2013 Uniform Transmission Rates are applied against historical 2012 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	492	$ 3.6300	$ 1,785	538	$ 0.7500	$ 404	538	$ 1.8500	$ 996	$ 1,399
February	480	$ 3.6300	$ 1,744	516	$ 0.7500	$ 387	516	$ 1.8500	$ 955	$ 1,342
March	446	$ 3.6300	$ 1,619	460	$ 0.7500	$ 345	460	$ 1.8500	$ 851	$ 1,196
April	1,950	$ 3.6300	$ 7,079	1,950	$ 0.7500	$ 1,463	1,950	$ 1.8500	$ 3,608	$ 5,071
May	7,751	$ 3.6300	$ 28,137	8,975	$ 0.7500	$ 6,731	8,975	$ 1.8500	$ 16,604	$ 23,335
June	9,068	$ 3.6300	$ 32,916	9,424	$ 0.7500	$ 7,068	9,424	$ 1.8500	$ 17,435	$ 24,503
July	412	$ 3.6300	$ 1,497	9,230	$ 0.7500	$ 6,923	9,230	$ 1.8500	$ 17,076	$ 23,998
August	413	$ 3.6300	$ 1,499	9,546	$ 0.7500	$ 7,159	9,546	$ 1.8500	$ 17,660	$ 24,819
September	410	$ 3.6300	$ 1,489	9,305	$ 0.7500	$ 6,979	9,305	$ 1.8500	$ 17,214	$ 24,192
October	9,603	$ 3.6300	$ 34,859	9,603	$ 0.7500	$ 7,202	9,603	$ 1.8500	$ 17,766	$ 24,968
November	483	$ 3.6300	$ 1,754	505	$ 0.7500	$ 379	505	$ 1.8500	$ 935	$ 1,314
December	440	$ 3.6300	$ 1,598	509	$ 0.7500	$ 382	509	$ 1.8500	$ 942	$ 1,324
Total	31,949	$ 3.63	$ 115,976	60,562	$ 0.75	$ 45,422	60,562	$ 1.85	$ 112,041	$ 157,462

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	16,288	$ 3.3265	$ 54,182	16,331	$ 0.7667	$ 12,521	16,331	$ 1.6300	$ 26,620	$ 39,142
February	16,056	$ 3.3265	$ 53,410	16,377	$ 0.7667	$ 12,556	16,377	$ 1.6300	$ 26,694	$ 39,250
March	15,236	$ 3.3265	$ 50,683	15,368	$ 0.7667	$ 11,783	15,368	$ 1.6300	$ 25,050	$ 36,833
April	15,003	$ 3.3265	$ 49,909	15,172	$ 0.7667	$ 11,632	15,172	$ 1.6300	$ 24,730	$ 36,363
May	15,457	$ 3.3265	$ 51,419	15,505	$ 0.7667	$ 11,888	15,505	$ 1.6300	$ 25,273	$ 37,161
June	15,698	$ 3.3265	$ 52,219	15,711	$ 0.7667	$ 12,046	15,711	$ 1.6300	$ 25,609	$ 37,655
July	15,953	$ 3.3265	$ 53,066	15,982	$ 0.7667	$ 12,254	15,982	$ 1.6300	$ 26,051	$ 38,305
August	15,523	$ 3.3265	$ 51,636	15,639	$ 0.7667	$ 11,991	15,639	$ 1.6300	$ 25,492	$ 37,482
September	15,215	$ 3.3265	$ 50,613	15,408	$ 0.7667	$ 11,814	15,408	$ 1.6300	$ 25,116	$ 36,929
October	14,574	$ 3.3265	$ 48,479	14,610	$ 0.7667	$ 11,201	14,610	$ 1.6300	$ 23,814	$ 35,015
November	15,291	$ 3.3265	$ 50,866	15,310	$ 0.7667	$ 11,738	15,310	$ 1.6300	$ 24,955	$ 36,693
December	15,361	$ 3.3265	$ 51,098	15,453	$ 0.7667	$ 11,848	15,453	$ 1.6300	$ 25,189	$ 37,037
Total	185,655	$ 3.33	$ 617,581	186,868	$ 0.77	$ 143,271	186,868	$ 1.63	$ 304,594	$ 447,866

Add Extra Host Here (I)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (II)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -



RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to calculate the expected billing when current 2013 Uniform Transmission Rates are applied against historical 2012 transmission units.

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	16,780	$3.34	$ 55,967	16,870	$0.77	$ 12,925	16,870	$1.64	$ 27,616	$ 40,541
February	16,537	$3.34	$ 55,155	16,893	$0.77	$ 12,943	16,893	$1.64	$ 27,649	$ 40,592
March	15,682	$3.34	$ 52,302	15,828	$0.77	$ 12,128	15,828	$1.64	$ 25,902	$ 38,030
April	16,954	$3.36	$ 56,988	17,122	$0.76	$ 13,095	17,122	$1.66	$ 28,338	$ 41,433
May	23,209	$3.43	$ 79,556	24,480	$0.76	$ 18,619	24,480	$1.71	$ 41,877	$ 60,496
June	24,766	$3.44	$ 85,135	25,136	$0.76	$ 19,114	25,136	$1.71	$ 43,045	$ 62,159
July	16,365	$3.33	$ 54,563	25,213	$0.76	$ 19,176	25,213	$1.71	$ 43,127	$ 62,303
August	15,936	$3.33	$ 53,135	25,185	$0.76	$ 19,150	25,185	$1.71	$ 43,151	$ 62,301
September	15,625	$3.33	$ 52,102	24,713	$0.76	$ 18,792	24,713	$1.71	$ 42,329	$ 61,122
October	24,177	$3.45	$ 83,339	24,213	$0.76	$ 18,404	24,213	$1.72	$ 41,580	$ 59,983
November	15,774	$3.34	$ 52,620	15,815	$0.77	$ 12,117	15,815	$1.64	$ 25,890	$ 38,007
December	15,801	$3.33	$ 52,696	15,963	$0.77	$ 12,230	15,963	$1.64	$ 26,131	$ 38,361
Total	217,604	$ 3.37	$ 733,557	247,430	$ 0.76	$ 188,693	247,430	$ 1.68	$ 416,635	$ 605,328



RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to calculate the expected billing when forecasted 2014 Uniform Transmission Rates are applied against historical 2012 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	492	$ 3.6300	$ 1,785	538	$ 0.7500	$ 404	538	$ 1.8500	$ 996	$ 1,399
February	480	$ 3.6300	$ 1,744	516	$ 0.7500	$ 387	516	$ 1.8500	$ 955	$ 1,342
March	446	$ 3.6300	$ 1,619	460	$ 0.7500	$ 345	460	$ 1.8500	$ 851	$ 1,196
April	1,950	$ 3.6300	$ 7,079	1,950	$ 0.7500	$ 1,463	1,950	$ 1.8500	$ 3,608	$ 5,071
May	7,751	$ 3.6300	$ 28,137	8,975	$ 0.7500	$ 6,731	8,975	$ 1.8500	$ 16,604	$ 23,335
June	9,068	$ 3.6300	$ 32,916	9,424	$ 0.7500	$ 7,068	9,424	$ 1.8500	$ 17,435	$ 24,503
July	412	$ 3.6300	$ 1,497	9,230	$ 0.7500	$ 6,923	9,230	$ 1.8500	$ 17,076	$ 23,998
August	413	$ 3.6300	$ 1,499	9,546	$ 0.7500	$ 7,159	9,546	$ 1.8500	$ 17,660	$ 24,819
September	410	$ 3.6300	$ 1,489	9,305	$ 0.7500	$ 6,979	9,305	$ 1.8500	$ 17,214	$ 24,192
October	9,603	$ 3.6300	$ 34,859	9,603	$ 0.7500	$ 7,202	9,603	$ 1.8500	$ 17,766	$ 24,968
November	483	$ 3.6300	$ 1,754	505	$ 0.7500	$ 379	505	$ 1.8500	$ 935	$ 1,314
December	440	$ 3.6300	$ 1,598	509	$ 0.7500	$ 382	509	$ 1.8500	$ 942	$ 1,324
Total	31,949	$ 3.63	$ 115,976	60,562	$ 0.75	$ 45,422	60,562	$ 1.85	$ 112,041	$ 157,462

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	16,288	$ 3.3265	$ 54,182	16,331	$ 0.7667	$ 12,521	16,331	$ 1.6300	$ 26,620	$ 39,142
February	16,056	$ 3.3265	$ 53,410	16,377	$ 0.7667	$ 12,556	16,377	$ 1.6300	$ 26,694	$ 39,250
March	15,236	$ 3.3265	$ 50,683	15,368	$ 0.7667	$ 11,783	15,368	$ 1.6300	$ 25,050	$ 36,833
April	15,003	$ 3.3265	$ 49,909	15,172	$ 0.7667	$ 11,632	15,172	$ 1.6300	$ 24,730	$ 36,363
May	15,457	$ 3.3265	$ 51,419	15,505	$ 0.7667	$ 11,888	15,505	$ 1.6300	$ 25,273	$ 37,161
June	15,698	$ 3.3265	$ 52,219	15,711	$ 0.7667	$ 12,046	15,711	$ 1.6300	$ 25,609	$ 37,655
July	15,953	$ 3.3265	$ 53,066	15,982	$ 0.7667	$ 12,254	15,982	$ 1.6300	$ 26,051	$ 38,305
August	15,523	$ 3.3265	$ 51,636	15,639	$ 0.7667	$ 11,991	15,639	$ 1.6300	$ 25,492	$ 37,482
September	15,215	$ 3.3265	$ 50,613	15,408	$ 0.7667	$ 11,814	15,408	$ 1.6300	$ 25,116	$ 36,929
October	14,574	$ 3.3265	$ 48,479	14,610	$ 0.7667	$ 11,201	14,610	$ 1.6300	$ 23,814	$ 35,015
November	15,291	$ 3.3265	$ 50,866	15,310	$ 0.7667	$ 11,738	15,310	$ 1.6300	$ 24,955	$ 36,693
December	15,361	$ 3.3265	$ 51,098	15,453	$ 0.7667	$ 11,848	15,453	$ 1.6300	$ 25,189	$ 37,037
Total	185,655	$ 3.33	$ 617,581	186,868	$ 0.77	$ 143,271	186,868	$ 1.63	$ 304,594	$ 447,866

Add Extra Host Here (I)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (II)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -



RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to calculate the expected billing when forecasted 2014 Uniform Transmission Rates are applied against historical 2012 transmission units.

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	16,780	$ 3.34	$ 55,967	16,870	$ 0.77	$ 12,925	16,870	$ 1.64	$ 27,616	$ 40,541
February	16,537	$ 3.34	$ 55,155	16,893	$ 0.77	$ 12,943	16,893	$ 1.64	$ 27,649	$ 40,592
March	15,682	$ 3.34	$ 52,302	15,828	$ 0.77	$ 12,128	15,828	$ 1.64	$ 25,902	$ 38,030
April	16,954	$ 3.36	$ 56,988	17,122	$ 0.76	$ 13,095	17,122	$ 1.66	$ 28,338	$ 41,433
May	23,209	$ 3.43	$ 79,556	24,480	$ 0.76	$ 18,619	24,480	$ 1.71	$ 41,877	$ 60,496
June	24,766	$ 3.44	$ 85,135	25,136	$ 0.76	$ 19,114	25,136	$ 1.71	$ 43,045	$ 62,159
July	16,365	$ 3.33	$ 54,563	25,213	$ 0.76	$ 19,176	25,213	$ 1.71	$ 43,127	$ 62,303
August	15,936	$ 3.33	$ 53,135	25,185	$ 0.76	$ 19,150	25,185	$ 1.71	$ 43,151	$ 62,301
September	15,625	$ 3.33	$ 52,102	24,713	$ 0.76	$ 18,792	24,713	$ 1.71	$ 42,329	$ 61,122
October	24,177	$ 3.45	$ 83,339	24,213	$ 0.76	$ 18,404	24,213	$ 1.72	$ 41,580	$ 59,983
November	15,774	$ 3.34	$ 52,620	15,815	$ 0.77	$ 12,117	15,815	$ 1.64	$ 25,890	$ 38,007
December	15,801	$ 3.33	$ 52,696	15,963	$ 0.77	$ 12,230	15,963	$ 1.64	$ 26,131	$ 38,361
Total	217,604	$ 3.37	$ 733,557	247,430	$ 0.76	$ 188,693	247,430	$ 1.68	$ 416,635	$ 605,328



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
Embedded Distributor	kW	$ 2.5638	74,022,802	253,301	$ 649,413	100.0%	$ 733,557	$2.8960
					$ 649,413			



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
Embedded Distributor	kW	$ 2.3365	74,022,802	253,301	$ 591,838	100.0%	$ 605,328	$2.3898
					$ 591,838			



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
Embedded Distributor	kW	$2.8960	74,022,802	253,301	733,556.99	100.0%	$ 733,557	$2.8960
					$ 733,557			



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
Embedded Distributor	kW	$ 2.3898	74,022,802	253,301	$ 605,328	100.0%	$ 605,328	$ 2.3898
					$ 605,328			



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 descriptions for the RTSRs are transfered automatically from Sheet 4 to Sheet 11, Column A.

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Embedded Distributor	kW	$ 2.8960	$ 2.3898

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2012-0129

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 Haldimand County 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, 2013.

BEFORE: Marika Hare
Presiding Member

REVISED RATE ORDER
(Issued April 11, 2013 and as corrected April 16, 2013)

Haldimand County Hydro Inc. ("HCHI") filed an application with the Ontario Energy Board (the "Board"), received on November 12, 2012 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 HCHI charges for electricity distribution, to be effective May 1, 2013. The Board assigned File Number EB-2012-0129 to the application.

The Board issued its rate order in this proceeding on April 11, 2013. Subsequently, HCHI informed the Board that it had discovered a typographical error in the Tariff of Rates and Charges issued with this order.

Specifically, the Board corrected the "Rate Rider for Smart Metering Entity Charge – effective until October 31, 2018" for a spelling error in the General Service Less Than 50 kW Service Classification. As a result, the Board has revised the Tariff of Rates and Charges for HCHI.

THE BOARD ORDERS THAT:

1. The revised Tariff of Rates and Charges set out in Appendix A, is effective May, 1, 2013 and will apply to electricity consumed or estimated to have been consumed on and after May 1, 2013.

2. The Tariff of Rates and Charges set out in Appendix "A" of this Order supersedes all previous Tariff of Rates and Charges approved by the Ontario Energy Board for Haldimand County Hydro Inc.'s service area, and is final in all respects.

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

DATED at Toronto, April 16, 2013

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

APPENDIX A

TO REVISED RATE ORDER

Haldimand County Hydro Inc.

EB-2012-0129

DATED: April 16, 2013

Haldimand County Hydro Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2013

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

EB-2012-0129

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to a customer's main place of abode and may include additional buildings served through the same meter, provided they are not rental income units. Residential includes Urban, Suburban and Farm customer's premises which can be occupied on a year-round and seasonal basis. Farm applies to properties actively engaged in agricultural production as defined by Statistics Canada. These premises must be supplied from a single phase primary line. The farm definition does not include tree, sod, or pet farms. Services to year-round pumping stations or other ancillary services remote from the main farm shall be classed as farm. 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. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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	$	18.17
Rate Rider for Disposition of Residual Historical Smart Meter Costs - effective until April 30, 2014	$	2.42
Rate Rider for Recovery of Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service-based rate order	$	3.47
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0265
Low Voltage Service Rate	$/kWh	0.0004
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014	$/kWh	(0.0023)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	(0.0010)
Rate Rider for Disposition of Deferred PILs Variance Account 1562 - effective until April 30, 2014	$/kWh	(0.0018)
Rate Rider for Application of Tax Change (2013) - effective until April 30, 2014	$/kWh	(0.0003)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0065
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0048

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Haldimand County Hydro Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2013

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

EB-2012-0129

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

General Service does include farms supplied from polyphase primary lines. General Service includes commercial, industrial, educational, administrative, auxiliary and government services. It also includes combination services where a variety of uses are made of the service by the owner of one property. This classification applies to a non residential account 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. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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	$	29.04
Rate Rider for Disposition of Residual Historical Smart Meter Costs - effective until April 30, 2014	$	3.91
Rate Rider for Recovery of Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service-based rate order	$	5.24
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0205
Low Voltage Service Rate	$/kWh	0.0003
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014	$/kWh	(0.0023)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	(0.0010)
Rate Rider for Disposition of Deferred PILs Variance Account 1562 - effective until April 30, 2014	$/kWh	(0.0012)
Rate Rider for Application of Tax Change (2013) - effective until April 30, 2014	$/kWh	(0.0002)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0058
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0044

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Haldimand County Hydro Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2013

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

EB-2012-0129

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

General Service does include farms supplied from polyphase primary lines. General Service includes commercial, industrial, educational, administrative, auxiliary and government services. It also includes combination services where a variety of uses are made of the service by the owner of one property. This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service. Note that for the application of the Retail Transmission Rate – Network Service Rate and the Retail Transmission Rate – Line and Transformation Connection Service Rate the following sub-classifications apply:

General Service 50 to 1,000 kW non-interval metered
General Service 50 to 1,000 kW interval metered
General Service greater than 1,000 to 5,000 kW interval metered.

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. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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	$	104.06
Rate Rider for Disposition of Residual Historical Smart Meter Costs - Non-Interval Metered - effective until April 30, 2014	$	2.49
Rate Rider for Recovery of Smart Meter Incremental Revenue Requirement - Non-Interval Metered – in effect until the effective date of the next cost of service-based rate order	$	9.75
Distribution Volumetric Rate	$/kW	4.8286
Low Voltage Service Rate	$/kW	0.1502
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014	$/kW	(0.8179)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	(0.3687)
Rate Rider for Disposition of Deferred PILs Variance Account 1562 - effective until April 30, 2014	$/kW	(0.1995)
Rate Rider for Application of Tax Change (2013) - effective until April 30, 2014	$/kW	(0.0271)
Retail Transmission Rate - Network Service Rate	$/kW	2.3783
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7325
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	2.5228
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	1.9149

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Haldimand County Hydro Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2013

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

EB-2012-0129

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, 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. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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)	$	20.83
Distribution Volumetric Rate	$/kWh	0.0027
Low Voltage Service Rate	$/kWh	0.0003
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014	$/kWh	(0.0025)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kWh	(0.0010)
Rate Rider for Disposition of Deferred PILs Variance Account 1562 - effective until April 30, 2014	$/kWh	(0.0016)
Rate Rider for Application of Tax Change (2013) - effective until April 30, 2014	$/kWh	(0.0002)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0058
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0044

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Haldimand County Hydro Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2013

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

EB-2012-0129

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to an account that is an unmetered lighting load supplied to a sentinel light. (Metered sentinel lighting is captured under the consumption of the principal service.) The consumption for these customers is assumed to have the same hourly consumption load profile as for Street Lighting. 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. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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)	$	12.99
Distribution Volumetric Rate	$/kW	33.5294
Low Voltage Service Rate	$/kW	0.1103
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014	$/kW	(1.3863)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	(0.3736)
Rate Rider for Disposition of Deferred PILs Variance Account 1562 - effective until April 30, 2014	$/kW	(2.2663)
Rate Rider for Application of Tax Change (2013) - effective until April 30, 2014	$/kW	(0.5613)
Retail Transmission Rate - Network Service Rate	$/kW	1.8025
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.3675

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Haldimand County Hydro Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2013

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

EB-2012-0129

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. 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. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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)	$	6.09
Distribution Volumetric Rate	$/kW	15.5853
Low Voltage Service Rate	$/kW	0.1081
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014	$/kW	(1.3045)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	(0.3553)
Rate Rider for Disposition of Deferred PILs Variance Account 1562 - effective until April 30, 2014	$/kW	(1.0803)
Rate Rider for Application of Tax Change (2013) - effective until April 30, 2014	$/kW	(0.2405)
Retail Transmission Rate - Network Service Rate	$/kW	1.7934
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.3395

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Haldimand County Hydro Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2013

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

EB-2012-0129

EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION FOR HYDRO ONE NETWORKS INC.

This classification applies to Hydro One Networks Inc., an electricity distributor licensed by the Board, and provided electricity by means of Haldimand County Hydro Inc.'s distribution facilities. 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. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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	$	184.32
Distribution Wheeling Service Rate	$/kW	0.5680
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014	$/kW	(0.6893)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	0.1488
Retail Transmission Rate - Network Service Rate	$/kW	2.5638
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.3365

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Haldimand County Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

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

EB-2012-0129

MICROFIT SERVICE CLASSIFICATION

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

Haldimand County Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

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

EB-2012-0129

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
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 forth Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration

Legal letter charge	$	15.00
Credit Reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	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
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
Temporary service install & remove – overhead – no transformer	$	500.00
Specific Charge for Access to the Power Poles - $/pole/year	$	22.35
Bell Canada Pole Rentals	$	18.08
Norfolk Pole Rentals – Billed	$	28.61

Haldimand County Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

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

EB-2012-0129

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 monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly 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	1.0680
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0573
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Embedded Distributor – Hydro One Networks Inc.	1.0305

Haldimand County Hydro Inc.
"PROPOSED" TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

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

EB-2013-0134

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to a customer's main place of abode and may include additional buildings served through the same meter, provided they are not rental income units. Residential includes Urban, Suburban and Farm customer's premises which can be occupied on a year-round and seasonal basis. Farm applies to properties actively engaged in agricultural production as defined by Statistics Canada. These premises must be supplied from a single phase primary line. The farm definition does not include tree, sod, or pet farms. Services to year-round pumping stations or other ancillary services remote from the main farm shall be classed as farm. 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. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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	$	18.85
Rate Rider for Smart Metering Entity Charge – effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0275
Low Voltage Service Rate	$/kWh	0.0004
Rate Rider for Disposition of Deferral/Variance Account (2014) – effective until April 30, 2015	$/kWh	(0.0014)
Rate Rider for Disposition of Global Adjustment Sub-Account (2014) – effective until April 30, 2015 Applicable only for Non-RPP Customers	$/kWh	0.0042
Rate Rider for Disposition of Stranded Meter Costs – effective until April 30, 2015	$/kWh	0.0021
Rate Rider for Disposition of Deferral/Variance Account 1576 for Accounting Changes under CGAAP - effective until April 30, 2019	$/kWh	(0.0016)
Renewable Energy Generation Funding Adder – effective until April 30, 2019	$/kWh	0.0002
Retail Transmission Rate – Network Service Rate	$/kWh	0.0065
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0049

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Haldimand County Hydro Inc.
"PROPOSED" TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

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EB-2013-0134

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

General Service does include farms supplied from polyphase primary lines. General Service includes commercial, industrial, educational, administrative, auxiliary and government services. It also includes combination services where a variety of uses are made of the service by the owner of one property. This classification applies to a non-residential account 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. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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	$	25.77
Rate Rider for Smart Metering Entity Charge – effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0182
Low Voltage Service Rate	$/kWh	0.0004
Rate Rider for Disposition of Deferral/Variance Account (2014) – effective until April 30, 2015	$/kWh	(0.0020)
Rate Rider for Disposition of Global Adjustment Sub-Account (2014) – effective until April 30, 2015 Applicable only for Non-RPP Customers	$/kWh	0.0042
Rate Rider for Disposition of Stranded Meter Costs – effective until April 30, 2015	$/kWh	0.0019
Rate Rider for Disposition of Deferral/Variance Account 1576 for Accounting Changes under CGAAP - effective until April 30, 2019	$/kWh	(0.0010)
Renewable Energy Generation Funding Adder – effective until April 30, 2019	$/kWh	0.0001
Retail Transmission Rate – Network Service Rate	$/kWh	0.0058
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0044

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Haldimand County Hydro Inc.
"PROPOSED" TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

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

EB-2013-0134

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

General Service does include farms supplied from polyphase primary lines. General Service includes commercial, industrial, educational, administrative, auxiliary and government services. It also includes combination services where a variety of uses are made of the service by the owner of one property. This classification applies to a non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 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. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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	$	84.98
Distribution Volumetric Rate	$/kW	3.9926
Low Voltage Service Rate	$/kW	0.1439
Rate Rider for Disposition of Deferral/Variance Account (2014) – effective until April 30, 2015	$/kW	(0.9630)
Rate Rider for Disposition of Global Adjustment Sub-Account (2014) – effective until April 30, 2015 Applicable only for Non-RPP Customers	$/kW	1.4815
Rate Rider for Disposition of Stranded Meter Costs – effective until April 30, 2015	$/kW	0.0571
Rate Rider for Disposition of Deferral/Variance Account 1576 for Accounting Changes under CGAAP - effective until April 30, 2019	$/kW	(0.1257)
Renewable Energy Generation Funding Adder – effective until April 30, 2019	$/kW	0.0188
Retail Transmission Rate – Network Service Rate	$/kW	2.4800
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.9031

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Haldimand County Hydro Inc.
"PROPOSED" TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

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EB-2013-0134

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, 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.

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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)	$	20.87
Distribution Volumetric Rate	$/kWh	0.0027
Low Voltage Service Rate	$/kWh	0.0004
Rate Rider for Disposition of Deferral/Variance Account (2014) – effective until April 30, 2015	$/kWh	(0.0003)
Rate Rider for Disposition of Global Adjustment Sub-Account (2014) – effective until April 30, 2015 Applicable only for Non-RPP Customers	$/kWh	0.0042
Rate Rider for Disposition of Deferral/Variance Account 1576 for Accounting Changes under CGAAP - effective until April 30, 2019	$/kWh	(0.0015)
Renewable Energy Generation Funding Adder – effective until April 30, 2019	$/kWh	0.0002
Retail Transmission Rate – Network Service Rate	$/kWh	0.0058
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Haldimand County Hydro Inc.
"PROPOSED" TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

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EB-2013-0134

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to an account that is an unmetered lighting load supplied to a sentinel light. (Metered sentinel lighting is captured under the consumption of the principal service.) The consumption for these customers is assumed to have the same hourly consumption load profile as for Street Lighting. 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. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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)	$	14.14
Distribution Volumetric Rate	$/kW	36.4943
Low Voltage Service Rate	$/kW	0.1210
Rate Rider for Disposition of Deferral/Variance Account (2014) – effective until April 30, 2015	$/kW	5.9957
Rate Rider for Disposition of Global Adjustment Sub-Account (2014) – effective until April 30, 2015 Applicable only for Non-RPP Customers	$/kW	1.4975
Rate Rider for Disposition of Deferral/Variance Account 1576 for Accounting Changes under CGAAP - effective until April 30, 2019	$/kW	(3.9156)
Renewable Energy Generation Funding Adder – effective until April 30, 2019	$/kW	0.5553
Retail Transmission Rate – Network Service Rate	$/kW	1.8003
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3957

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Haldimand County Hydro Inc.
"PROPOSED" TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

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EB-2013-0134

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. 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. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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)	$	6.10
Distribution Volumetric Rate	$/kW	15.6168
Low Voltage Service Rate	$/kW	0.1115
Rate Rider for Disposition of Deferral/Variance Account (2014) – effective until April 30, 2015	$/kW	(1.5513)
Rate Rider for Disposition of Global Adjustment Sub-Account (2014) – effective until April 30, 2015 Applicable only for Non-RPP Customers	$/kW	1.4944
Rate Rider for Disposition of Deferral/Variance Account 1576 for Accounting Changes under CGAAP - effective until April 30, 2019	$/kW	(1.4566)
Renewable Energy Generation Funding Adder – effective until April 30, 2019	$/kW	0.2194
Retail Transmission Rate – Network Service Rate	$/kW	1.7912
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3671

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Haldimand County Hydro Inc.
"PROPOSED" TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

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EB-2013-0134

EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION FOR HYDRO ONE NETWORKS INC.

This classification applies to Hydro One Networks Inc., an electricity distributor licensed by the Board, and provided electricity by means of Haldimand County Hydro Inc.'s distribution facilities. 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. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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	$	478.04
Distribution Wheeling Service Rate	$/kW	1.4731
Rate Rider for Disposition of Deferral/Variance Account (2014) – effective until April 30, 2015	$/kW	0.5729
Rate Rider for Disposition of Global Adjustment Sub-Account (2014) – effective until April 30, 2015 Applicable only for Non-RPP Customers	$/kW	(0.0465)
Retail Transmission Rate – Network Service Rate	$/kW	2.8960
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.3898

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Haldimand County Hydro Inc.
"PROPOSED" TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

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EB-2013-0134

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 charged 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

Haldimand County Hydro Inc.
"PROPOSED" TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

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EB-2013-0134

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
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 charged 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.

Customer Administration

Legal letter charge	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	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
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
Temporary service install & remove – overhead – no transformer	$	500.00
Specific Charge for Access to the Power Poles – $/pole/year	$	22.35
Bell Canada Pole Rentals	$	18.08
Norfolk Pole Rentals – Billed	$	28.61

Haldimand County Hydro Inc.
"PROPOSED" TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

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

EB-2013-0134

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 charged 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	1.0663
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0556
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Embedded Distributor – Hydro One Networks Inc.	1.0288

Haldimand County Hydro Inc.

"PROPOSED" TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2014~~13~~

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

EB-2013-0134~~2-0129~~

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to a customer's main place of abode and may include additional buildings served through the same meter, provided they are not rental income units. Residential includes Urban, Suburban and Farm customer's premises which can be occupied on a year-round and seasonal basis. Farm applies to properties actively engaged in agricultural production as defined by Statistics Canada. These premises must be supplied from a single phase primary line. The farm definition does not include tree, sod, or pet farms. Services to year-round pumping stations or other ancillary services remote from the main farm shall be classed as farm. 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. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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	$	18.85~~17~~
~~Rate Rider for Disposition of Residual Historical Smart Meter Costs – effective until April 30, 2014~~	~~$~~	~~2.42~~
~~Rate Rider for Recovery of Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service-based rate order~~	~~$~~	~~3.47~~
Rate Rider for Smart Metering Entity Charge – effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.027565
Low Voltage Service Rate	$/kWh	0.0004
Rate Rider for Disposition of Deferral/Variance Account (2014~~3~~) – effective until April 30, 2015~~4~~	$/kWh	(0.001~~423~~)
Rate Rider for Disposition of Global Adjustment Sub-Account (2014~~3~~) – effective until April 30, 2015~~4~~ Applicable only for Non-RPP Customers	$/kWh	0.0042~~(0.0010)~~
~~Rate Rider for Disposition of Deferred PILs Variance Account 1562 – effective until April 30, 2014~~	~~$/kWh~~	~~(0.0018)~~
~~Rate Rider for Application of Tax Change (2013) – effective until April 30, 2014~~	~~$/kWh~~	~~(0.0003)~~
Rate Rider for Disposition of Stranded Meter Costs – effective until April 30, 2015	$/kWh	0.0021
Rate Rider for Disposition of Deferral/Variance Account 1576 for Accounting Changes under CGAAP - effective until April 30, 2019	$/kWh	(0.0016)
Renewable Energy Generation Funding Adder – effective until April 30, 2019	$/kWh	0.0002
Retail Transmission Rate – Network Service Rate	$/kWh	0.0065
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.004~~98~~

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MONTHLY RATES AND CHARGES – Regulatory Component

Haldimand County Hydro Inc.
"PROPOSED" TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 20143

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

EB-2013-0134-0129

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

General Service does include farms supplied from polyphase primary lines. General Service includes commercial, industrial, educational, administrative, auxiliary and government services. It also includes combination services where a variety of uses are made of the service by the owner of one property. This classification applies to a non residential account 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.

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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	$	25.779.04
Rate Rider for Disposition of Residual Historical Smart Meter Costs – effective until April 30, 2014	$	3.91
Rate Rider for Recovery of Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service-based rate order	$	5.24
Rate Rider for Smart Metering Entity Charge – effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0182205
Low Voltage Service Rate	$/kWh	0.00043
Rate Rider for Disposition of Deferral/Variance Account (20143) – effective until April 30, 20154	$/kWh	(0.00203)
Rate Rider for Disposition of Global Adjustment Sub-Account (20143) – effective until April 30, 20154 Applicable only for Non-RPP Customers	$/kWh	0.0042(0.0010)
Rate Rider for Disposition of Deferred PILs Variance Account 1562 – effective until April 30, 2014	$/kWh	(0.0012)
Rate Rider for Application of Tax Change (2013) – effective until April 30, 2014	$/kWh	(0.0002)
Rate Rider for Disposition of Stranded Meter Costs – effective until April 30, 2015	$/kWh	0.0019
Rate Rider for Disposition of Deferral/Variance Account 1576 for Accounting Changes under CGAAP - effective until April 30, 2019	$/kWh	(0.0010)
Renewable Energy Generation Funding Adder – effective until April 30, 2019	$/kWh	0.0001
Retail Transmission Rate – Network Service Rate	$/kWh	0.0058
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0044

Haldimand County Hydro Inc.

"PROPOSED" TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2014~~3~~

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

EB-2013-0134~~2-0129~~

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Haldimand County Hydro Inc.

"PROPOSED" TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2014~~3~~

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EB-2013-0134~~2-0129~~

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

General Service does include farms supplied from polyphase primary lines. General Service includes commercial, industrial, educational, administrative, auxiliary and government services. It also includes combination services where a variety of uses are made of the service by the owner of one property. This classification applies to a ~~non residential~~non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service. ~~Note that for the application of the Retail Transmission Rate – Network Service Rate and the Retail Transmission Rate – Line and Transformation Connection Service Rate the following sub-classifications apply:~~

~~General Service 50 to 1,000 kW non-interval metered~~

~~General Service 50 to 1,000 kW interval metered~~

~~General Service greater than 1,000 to 5,000 kW interval metered.~~

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APPLICATION

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	84.98~~104.06~~
~~Rate Rider for Disposition of Residual Historical Smart Meter Costs – Non-Interval Metered – effective until April 30, 2014~~	~~$~~	~~2.49~~
~~Rate Rider for Recovery of Smart Meter Incremental Revenue Requirement – Non-Interval Metered in effect until the effective date of the next cost of service-based rate order~~	~~$~~	~~9.75~~
Distribution Volumetric Rate	$/kW	3.9926~~4.8286~~
Low Voltage Service Rate	$/kW	0.143950~~2~~
Rate Rider for Disposition of Deferral/Variance Account (2014~~3~~) – effective until April 30, 2015~~4~~	$/kW	(0.9630~~8179~~)
Rate Rider for Disposition of Global Adjustment Sub-Account (2014~~3~~) – effective until April 30, 2015~~4~~ Applicable only for Non-RPP Customers	$/kW	1.4815~~(0.3687)~~
~~Rate Rider for Disposition of Deferred PILs Variance Account 1562 – effective until April 30, 2014~~	~~$/kW~~	~~(0.1995)~~
~~Rate Rider for Application of Tax Change (2013) – effective until April 30, 2014~~	~~$/kW~~	~~(0.0271)~~
Rate Rider for Disposition of Stranded Meter Costs – effective until April 30, 2015	$/kW	0.0571
Rate Rider for Disposition of Deferral/Variance Account 1576 for Accounting Changes under CGAAP - effective until April 30, 2019	$/kW	(0.1257)
Renewable Energy Generation Funding Adder – effective until April 30, 2019	$/kW	0.0188
Retail Transmission Rate – Network Service Rate	$/kW	2.4800~~3783~~

Haldimand County Hydro Inc.

"PROPOSED" TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2014~~3~~

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

EB-2013-0134~~2-0129~~

Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.90317325
~~Retail Transmission Rate – Network Service Rate – Interval Metered~~	~~$/kW~~	~~2.5228~~
~~Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered~~	~~$/kW~~	~~1.9149~~

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Haldimand County Hydro Inc.

"PROPOSED" TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2014~~3~~

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EB-2013-0134~~2-0129~~

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, 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

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	20.87~~3~~
Distribution Volumetric Rate	$/kWh	0.0027
Low Voltage Service Rate	$/kWh	0.0004~~3~~
Rate Rider for Disposition of Deferral/Variance Account (2014~~3~~) – effective until April 30, 2015~~4~~	$/kWh	(0.0003~~25~~)
Rate Rider for Disposition of Global Adjustment Sub-Account (2014~~3~~) – effective until April 30, 2015~~4~~ Applicable only for Non-RPP Customers	$/kWh	0.0042~~(0.0010)~~
~~Rate Rider for Disposition of Deferred PILs Variance Account 1562 effective until April 30, 2014~~	~~$/kWh~~	~~(0.0016)~~
~~Rate Rider for Application of Tax Change (2013) – effective until April 30, 2014~~	~~$/kWh~~	~~(0.0002)~~
Rate Rider for Disposition of Deferral/Variance Account 1576 for Accounting Changes under CGAAP - effective until April 30, 2019	$/kWh	(0.0015)
Renewable Energy Generation Funding Adder – effective until April 30, 2019	$/kWh	0.0002
Retail Transmission Rate – Network Service Rate	$/kWh	0.0058
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.004~~5~~4

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Haldimand County Hydro Inc.

"PROPOSED" TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 20143

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

EB-2013-01342-0129

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to an account that is an unmetered lighting load supplied to a sentinel light. (Metered sentinel lighting is captured under the consumption of the principal service.) The consumption for these customers is assumed to have the same hourly consumption load profile as for Street Lighting. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	14.142.99
Distribution Volumetric Rate	$/kW	36.49433.5294
Low Voltage Service Rate	$/kW	0.1210103
Rate Rider for Disposition of Deferral/Variance Account (20143) – effective until April 30, 2054	$/kW	5.9957(1.3863)
Rate Rider for Disposition of Global Adjustment Sub-Account (20143) – effective until April 30, 2054 Applicable only for Non-RPP Customers	$/kW	1.4975(0.3736)
~~Rate Rider for Disposition of Deferred PILs Variance Account 1562 – effective until April 30, 2014~~	~~$/kW~~	~~(2.2663)~~
~~Rate Rider for Application of Tax Change (2013) – effective until April 30, 2014~~	~~$/kW~~	~~(0.5613)~~
Rate Rider for Disposition of Deferral/Variance Account 1576 for Accounting Changes under CGAAP - effective until April 30, 2019	$/kW	(3.9156)
Renewable Energy Generation Funding Adder – effective until April 30, 2019	$/kW	0.5553
Retail Transmission Rate – Network Service Rate	$/kW	1.8003325
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3957675

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Haldimand County Hydro Inc.

"PROPOSED" TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2014~~3~~

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

EB-2013-0134~~2-0129~~

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. 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)	$	6.10~~09~~
Distribution Volumetric Rate	$/kW	15.6168~~5853~~
Low Voltage Service Rate	$/kW	0.1115~~081~~
Rate Rider for Disposition of Deferral/Variance Account (2014~~3~~) – effective until April 30, 2015~~4~~	$/kW	(1.5513~~3045~~)
Rate Rider for Disposition of Global Adjustment Sub-Account (2014~~3~~) – effective until April 30, 2015~~4~~ Applicable only for Non-RPP Customers	$/kW	1.4944~~(0.3553)~~
~~Rate Rider for Disposition of Deferred PILs Variance Account 1562 – effective until April 30, 2014~~	~~$/kW~~	~~(1.0803)~~
~~Rate Rider for Application of Tax Change (2013) – effective until April 30, 2014~~	~~$/kW~~	~~(0.2405)~~
Rate Rider for Disposition of Deferral/Variance Account 1576 for Accounting Changes under CGAAP - effective until April 30, 2019	$/kW	(1.4566)
Renewable Energy Generation Funding Adder – effective until April 30, 2019	$/kW	0.2194
Retail Transmission Rate – Network Service Rate	$/kW	1.791~~2~~34
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.367~~1~~395

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Haldimand County Hydro Inc.

"PROPOSED" TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2014~~3~~

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EB-2013-0134~~2-0129~~

EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION FOR HYDRO ONE NETWORKS INC.

This classification applies to Hydro One Networks Inc., an electricity distributor licensed by the Board, and provided electricity by means of Haldimand County Hydro Inc.'s distribution facilities. 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	$	478.04~~184.32~~
Distribution Wheeling Service Rate	$/kW	1.4731~~0.5680~~
Rate Rider for Disposition of Deferral/Variance Account (2014~~3~~) – effective until April 30, 2015~~4~~	$/kW	0.5729~~(0.6893)~~
Rate Rider for Disposition of Global Adjustment Sub-Account (2014~~3~~) – effective until April 30, 2015~~4~~ Applicable only for Non-RPP Customers	$/kW	(0.0465)~~0.1488~~
Retail Transmission Rate – Network Service Rate	$/kW	2.8960~~5638~~
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.3898~~3365~~

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Haldimand County Hydro Inc.

"PROPOSED" TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2014~~3~~

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EB-2013-0134~~2-0129~~

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.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.40

Haldimand County Hydro Inc.

"PROPOSED" TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2014~~3~~

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EB-2013-0134~~2-0129~~

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
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.

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Customer Administration

Legal letter charge	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	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
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
Temporary service install & remove – overhead – no transformer	$	500.00
Specific Charge for Access to the Power Poles – $/pole/year	$	22.35
Bell Canada Pole Rentals	$	18.08
Norfolk Pole Rentals – Billed	$	28.61

Haldimand County Hydro Inc.

"PROPOSED" TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2014~~3~~

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

EB-2013-0134~~2-0129~~

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.

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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	1.0663~~80~~
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0556~~73~~
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Embedded Distributor – Hydro One Networks Inc.	1.0288~~305~~

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Appendix 2-W
Bill Impacts

Customer Class: RESIDENTIAL (250 kWh)

TOU / non-TOU: TOU

Consumption 250 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 18.1700	1	$ 18.17	$ 18.8500	1	$ 18.85	$ 0.68	3.74%
Smart Meter Rate Adder	Monthly	$ 5.8900	1	$ 5.89		1	$ -	-$ 5.89	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0265	800	$ 21.20	$ 0.0275	800	$ 22.00	$ 0.80	3.77%
Smart Meter Disposition Rider			800	$ -		800	$ -	$ -	
LRAM & SSM Rate Rider			800	$ -		800	$ -	$ -	
Shared Tax Savings Rate Rider	per kWh	-$ 0.0003	800	-$ 0.24		800	$ -	$ 0.24	-100.00%
PILs a/c 1562 Disposition Rate Rider	per kWh	-$ 0.0018	800	-$ 1.44		800	$ -	$ 1.44	-100.00%
Stranded Meter Rate Rider	per kWh		800	$ -	$ 0.0021	800	$ 1.68	$ 1.68	
PPE Adjustment a/c 1576 Rate Rider	per kWh		800	$ -	-$ 0.0016	800	-$ 1.28	-$ 1.28	
REG Investment Rate Funding Adder	per kWh		800	$ -	$ 0.0002	800	$ 0.16	$ 0.16	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Sub-Total A (excluding pass through)				$ 43.58			$ 41.41	**-$ 2.17**	**-4.98%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0023	800	-$ 1.84	-$ 0.0014	800	-$ 1.12	$ 0.72	39.13%
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0004	800	$ 0.32	$ 0.0004	800	$ 0.32	$ -	0.00%
Line Losses on Cost of Power	per kWh	$ 0.0839	54.4	$ 4.57	$ 0.0839	53.04	$ 4.45	-$ 0.11	-2.50%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 47.42**			**$ 45.85**	**-$ 1.56**	**-3.30%**
RTSR - Network	per kWh	$ 0.0065	267	$ 1.74	$ 0.0065	267	$ 1.73	-$ 0.00	-0.16%
RTSR - Line and Transformation Connection	per kWh	$ 0.0048	267	$ 1.28	$ 0.0049	267	$ 1.31	$ 0.02	1.92%
Sub-Total C - Delivery (including Sub-Total B)				**$ 50.43**			**$ 48.89**	**-$ 1.54**	**-3.06%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	267	$ 1.17	$ 0.0044	267	$ 1.17	-$ 0.00	-0.16%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	267	$ 0.32	$ 0.0012	267	$ 0.32	-$ 0.00	-0.16%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	250	$ 1.75	$ 0.0070	250	$ 1.75	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	512	$ 34.30	$ 0.0670	512	$ 34.30	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	144	$ 14.98	$ 0.1040	144	$ 14.98	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	144	$ 17.86	$ 0.1240	144	$ 17.86	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 121.06**			**$ 119.52**	**-$ 1.54**	**-1.28%**
HST		13%		$ 15.74	13%		$ 15.54	-$ 0.20	-1.28%
Total Bill (including HST)				$ 136.80			$ 135.06	-$ 1.75	-1.28%
Ontario Clean Energy Benefit [1]				-$ 13.68			-$ 13.51	$ 0.17	-1.24%
Total Bill on TOU (including OCEB)				**$ 123.12**			**$ 121.55**	**-$ 1.58**	**-1.28%**
Loss Factor (%)		6.8000%			6.6300%				

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Appendix 2-W
Bill Impacts

Customer Class: **RESIDENTIAL (800 kWh)**

TOU / non-TOU: TOU

Consumption **800** **kWh** ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 18.1700	1	$ 18.17	$ 18.8500	1	$ 18.85	$ 0.68	3.74%
Smart Meter Rate Adder	Monthly	$ 5.8900	1	$ 5.89		1	$ -	-$ 5.89	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0265	800	$ 21.20	$ 0.0275	800	$ 22.00	$ 0.80	3.77%
Smart Meter Disposition Rider			800	$ -		800	$ -	$ -	
LRAM & SSM Rate Rider			800	$ -		800	$ -	$ -	
Shared Tax Savings Rate Rider	per kWh	-$ 0.0003	800	-$ 0.24		800	$ -	$ 0.24	-100.00%
PILs a/c 1562 Disposition Rate Rider	per kWh	-$ 0.0018	800	-$ 1.44		800	$ -	$ 1.44	-100.00%
Stranded Meter Rate Rider	per kWh		800	$ -	$ 0.0021	800	$ 1.68	$ 1.68	
PPE Adjustment a/c 1576 Rate Rider	per kWh		800	$ -	-$ 0.0016	800	-$ 1.28	-$ 1.28	
REG Investment Rate Funding Adder	per kWh		800	$ -	$ 0.0002	800	$ 0.16	$ 0.16	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Sub-Total A (excluding pass through)				$ 43.58			$ 41.41	**-$ 2.17**	**-4.98%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0023	800	-$ 1.84	-$ 0.0014	800	-$ 1.12	$ 0.72	39.13%
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0004	800	$ 0.32	$ 0.0004	800	$ 0.32	$ -	0.00%
Line Losses on Cost of Power	per kWh	$ 0.0839	54.4	$ 4.57	$ 0.0839	53.04	$ 4.45	-$ 0.11	-2.50%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 47.42**			**$ 45.85**	**-$ 1.56**	**-3.30%**
RTSR - Network	per kWh	$ 0.0065	854	$ 5.55	$ 0.0065	853	$ 5.54	-$ 0.01	-0.16%
RTSR - Line and Transformation Connection	per kWh	$ 0.0048	854	$ 4.10	$ 0.0049	853	$ 4.18	$ 0.08	1.92%
Sub-Total C - Delivery (including Sub-Total B)				**$ 57.07**			**$ 55.58**	**-$ 1.49**	**-2.62%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	854	$ 3.76	$ 0.0044	853	$ 3.75	-$ 0.01	-0.16%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	854	$ 1.03	$ 0.0012	853	$ 1.02	-$ 0.00	-0.16%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	512	$ 34.30	$ 0.0670	512	$ 34.30	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	144	$ 14.98	$ 0.1040	144	$ 14.98	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	144	$ 17.86	$ 0.1240	144	$ 17.86	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 134.84**			**$ 133.34**	**-$ 1.50**	**-1.11%**
HST		13%		$ 17.53	13%		$ 17.33	-$ 0.20	-1.11%
Total Bill (including HST)				$ 152.37			$ 150.67	-$ 1.70	-1.11%
Ontario Clean Energy Benefit [1]				-$ 15.24			-$ 15.07	$ 0.17	-1.12%
Total Bill on TOU (including OCEB)				**$ 137.13**			**$ 135.60**	**-$ 1.53**	**-1.11%**
Loss Factor (%)		6.8000%			6.6300%				

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Appendix 2-W
Bill Impacts

Customer Class: **RESIDENTIAL (1500 kWh)**

TOU / non-TOU: TOU

Consumption 1,500 **kWh** (●) May 1 - October 31 ( ) November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 18.1700	1	$ 18.17	$ 18.8500	1	$ 18.85	$ 0.68	3.74%
Smart Meter Rate Adder	Monthly	$ 5.8900	1	$ 5.89		1	$ -	-$ 5.89	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0265	800	$ 21.20	$ 0.0275	800	$ 22.00	$ 0.80	3.77%
Smart Meter Disposition Rider			800	$ -		800	$ -	$ -	
LRAM & SSM Rate Rider			800	$ -		800	$ -	$ -	
Shared Tax Savings Rate Rider	per kWh	-$ 0.0003	800	-$ 0.24		800	$ -	$ 0.24	-100.00%
PILs a/c 1562 Disposition Rate Rider	per kWh	-$ 0.0018	800	-$ 1.44		800	$ -	$ 1.44	-100.00%
Stranded Meter Rate Rider	per kWh		800	$ -	$ 0.0021	800	$ 1.68	$ 1.68	
PPE Adjustment a/c 1576 Rate Rider	per kWh		800	$ -	-$ 0.0016	800	-$ 1.28	-$ 1.28	
REG Investment Rate Funding Adder	per kWh		800	$ -	$ 0.0002	800	$ 0.16	$ 0.16	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Sub-Total A (excluding pass through)				$ 43.58			$ 41.41	**-$ 2.17**	**-4.98%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0023	800	-$ 1.84	-$ 0.0014	800	-$ 1.12	$ 0.72	39.13%
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0004	800	$ 0.32	$ 0.0004	800	$ 0.32	$ -	0.00%
Line Losses on Cost of Power	per kWh	$ 0.0839	54.4	$ 4.57	$ 0.0839	53.04	$ 4.45	-$ 0.11	-2.50%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 47.42**			**$ 45.85**	**-$ 1.56**	**-3.30%**
RTSR - Network	per kWh	$ 0.0065	1602	$ 10.41	$ 0.0065	1599	$ 10.40	-$ 0.02	-0.16%
RTSR - Line and Transformation Connection	per kWh	$ 0.0048	1602	$ 7.69	$ 0.0049	1599	$ 7.84	$ 0.15	1.92%
Sub-Total C - Delivery (including Sub-Total B)				**$ 65.52**			**$ 64.08**	**-$ 1.43**	**-2.19%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	1602	$ 7.05	$ 0.0044	1599	$ 7.04	-$ 0.01	-0.16%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	1602	$ 1.92	$ 0.0012	1599	$ 1.92	-$ 0.00	-0.16%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1500	$ 10.50	$ 0.0070	1500	$ 10.50	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	512	$ 34.30	$ 0.0670	512	$ 34.30	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	144	$ 14.98	$ 0.1040	144	$ 14.98	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	144	$ 17.86	$ 0.1240	144	$ 17.86	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 152.38**			**$ 150.93**	**-$ 1.45**	**-0.95%**
HST		13%		$ 19.81	13%		$ 19.62	-$ 0.19	-0.95%
Total Bill (including HST)				$ 172.18			$ 170.55	-$ 1.64	-0.95%
Ontario Clean Energy Benefit [1]				-$ 17.22			-$ 17.05	$ 0.17	-0.99%
Total Bill on TOU (including OCEB)				**$ 154.96**			**$ 153.50**	**-$ 1.47**	**-0.95%**
Loss Factor (%)		6.8000%			6.6300%				

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Appendix 2-W
Bill Impacts

Customer Class: GENERAL SERVICE LESS THAN 50 KW (2,000 kWh)

TOU / non-TOU: TOU

Consumption 2,000 **kWh** ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 29.0400	1	$ 29.04	$ 25.7700	1	$ 25.77	-$ 3.27	-11.26%
Smart Meter Rate Adder	Monthly	$ 9.1500	1	$ 9.15		1	$ -	-$ 9.15	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0205	2,000	$ 41.00	$ 0.0182	2,000	$ 36.40	-$ 4.60	-11.22%
Smart Meter Disposition Rider			2,000	$ -		2,000	$ -	$ -	
LRAM & SSM Rate Rider			2,000	$ -		2,000	$ -	$ -	
Shared Tax Savings Rate Rider	per kWh	-$ 0.0002	2,000	-$ 0.40		2,000	$ -	$ 0.40	-100.00%
PILs a/c 1562 Disposition Rate Rider	per kWh	-$ 0.0012	2,000	-$ 2.40		2,000	$ -	$ 2.40	-100.00%
Stranded Meter Rate Rider	per kWh		2,000	$ -	$ 0.0019	2,000	$ 3.80	$ 3.80	
PPE Adjustment a/c 1576 Rate Rider	per kWh		2,000	$ -	-$ 0.0010	2,000	-$ 2.00	-$ 2.00	
REG Investment Rate Funding Adder	per kWh		2,000	$ -	$ 0.0001	2,000	$ 0.20	$ 0.20	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 76.39			$ 64.17	**-$ 12.22**	**-16.00%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0023	2,000	-$ 4.60	-$ 0.0020	2,000	-$ 4.00	$ 0.60	13.04%
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0003	2,000	$ 0.60	$ 0.0004	2,000	$ 0.80	$ 0.20	33.33%
Line Losses on Cost of Power	per kWh	$ 0.0839	136.00	$ 11.41	$ 0.0839	132.60	$ 11.13	-$ 0.29	-2.50%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 84.59**			**$ 72.89**	**-$ 11.71**	**-13.84%**
RTSR - Network	per kWh	$ 0.0058	2136	$ 12.39	$ 0.0058	2133	$ 12.37	-$ 0.02	-0.16%
RTSR - Line and Transformation Connection	per kWh	$ 0.0044	2136	$ 9.40	$ 0.0045	2133	$ 9.60	$ 0.20	2.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 106.38**			**$ 94.85**	**-$ 11.53**	**-10.84%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2136	$ 9.40	$ 0.0044	2133	$ 9.38	-$ 0.01	-0.16%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	2136	$ 2.56	$ 0.0012	2133	$ 2.56	-$ 0.00	-0.16%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	1280	$ 85.76	$ 0.0670	1280	$ 85.76	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	360	$ 37.44	$ 0.1040	360	$ 37.44	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	360	$ 44.64	$ 0.1240	360	$ 44.64	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 300.43**			**$ 288.89**	**-$ 11.55**	**-3.84%**
HST		13%		$ 39.06	13%		$ 37.56	-$ 1.50	-3.84%
Total Bill (including HST)				$ 339.49			$ 326.44	-$ 13.05	-3.84%
Ontario Clean Energy Benefit [1]				-$ 33.95			-$ 32.64	$ 1.31	-3.86%
Total Bill on TOU (including OCEB)				**$ 305.54**			**$ 293.80**	**-$ 11.74**	**-3.84%**
Loss Factor (%)		6.8000%			6.6300%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

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Appendix 2-W
Bill Impacts

Customer Class: GENERAL SERVICE LESS THAN 50 KW (5,000 kWh)

TOU / non-TOU: TOU

Consumption 5,000 **kWh** ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 29.0400	1	$ 29.04	$ 25.7700	1	$ 25.77	-$ 3.27	-11.26%
Smart Meter Rate Adder	Monthly	$ 9.1500	1	$ 9.15		1	$ -	-$ 9.15	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0205	2,000	$ 41.00	$ 0.0182	2,000	$ 36.40	-$ 4.60	-11.22%
Smart Meter Disposition Rider			2,000	$ -		2,000	$ -	$ -	
LRAM & SSM Rate Rider			2,000	$ -		2,000	$ -	$ -	
Shared Tax Savings Rate Rider	per kWh	-$ 0.0002	2,000	-$ 0.40		2,000	$ -	$ 0.40	-100.00%
PILs a/c 1562 Disposition Rate Rider	per kWh	-$ 0.0012	2,000	-$ 2.40		2,000	$ -	$ 2.40	-100.00%
Stranded Meter Rate Rider	per kWh		2,000	$ -	$ 0.0019	2,000	$ 3.80	$ 3.80	
PPE Adjustment a/c 1576 Rate Rider	per kWh		2,000	$ -	-$ 0.0010	2,000	-$ 2.00	-$ 2.00	
REG Investment Rate Funding Adder	per kWh		2,000	$ -	$ 0.0001	2,000	$ 0.20	$ 0.20	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 76.39			$ 64.17	**-$ 12.22**	**-16.00%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0023	2,000	-$ 4.60	-$ 0.0020	2,000	-$ 4.00	$ 0.60	13.04%
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0003	2,000	$ 0.60	$ 0.0004	2,000	$ 0.80	$ 0.20	33.33%
Line Losses on Cost of Power	per kWh	$ 0.0839	136.00	$ 11.41	$ 0.0839	132.60	$ 11.13	-$ 0.29	-2.50%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 84.59**			**$ 72.89**	**-$ 11.71**	**-13.84%**
RTSR - Network	per kWh	$ 0.0058	5340	$ 30.97	$ 0.0058	5332	$ 30.92	-$ 0.05	-0.16%
RTSR - Line and Transformation Connection	per kWh	$ 0.0044	5340	$ 23.50	$ 0.0045	5332	$ 23.99	$ 0.50	2.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 139.06**			**$ 127.80**	**-$ 11.26**	**-8.10%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	5340	$ 23.50	$ 0.0044	5332	$ 23.46	-$ 0.04	-0.16%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	5340	$ 6.41	$ 0.0012	5332	$ 6.40	-$ 0.01	-0.16%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	5000	$ 35.00	$ 0.0070	5000	$ 35.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0670	1280	$ 85.76	$ 0.0670	1280	$ 85.76	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1040	360	$ 37.44	$ 0.1040	360	$ 37.44	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1240	360	$ 44.64	$ 0.1240	360	$ 44.64	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 372.06**			**$ 360.75**	**-$ 11.31**	**-3.04%**
HST		13%		$ 48.37	13%		$ 46.90	-$ 1.47	-3.04%
Total Bill (including HST)				$ 420.42			$ 407.65	-$ 12.78	-3.04%
Ontario Clean Energy Benefit [1]				-$ 42.04			-$ 40.76	$ 1.28	-3.04%
Total Bill on TOU (including OCEB)				**$ 378.38**			**$ 366.89**	**-$ 11.50**	**-3.04%**

Loss Factor (%) 6.8000% 6.6300%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

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Appendix 2-W
Bill Impacts

Customer Class: GENERAL SERVICE 50 TO 4,999 KW (50,000 kWh; 75 kW)

TOU / non-TOU: non-TOU

Consumption 50,000 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)
75 kW

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 104.0600	1	$ 104.06	$ 84.9800	1	$ 84.98	-$ 19.08	-18.34%
Smart Meter Rate Adder	Monthly	$ 12.2400	1	$ 12.24		1	$ -	-$ 12.24	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 4.8286	75	$ 362.15	$ 3.9926	75	$ 299.45	-$ 62.70	-17.31%
Smart Meter Disposition Rider			75	$ -		75	$ -	$ -	
LRAM & SSM Rate Rider			75	$ -		75	$ -	$ -	
Shared Tax Savings Rate Rider	per kW	-$ 0.0271	75	-$ 2.03		75	$ -	$ 2.03	-100.00%
PILs a/c 1562 Disposition Rate Rider	per kW	-$ 0.1995	75	-$ 14.96		75	$ -	$ 14.96	-100.00%
Stranded Meter Rate Rider	per kW		75	$ -	$ 0.0571	75	$ 4.28	$ 4.28	
PPE Adjustment a/c 1576 Rate Rider	per kW		75	$ -	-$ 0.1257	75	-$ 9.43	-$ 9.43	
REG Investment Rate Funding Adder	per kW		75	$ -	$ 0.0188	75	$ 1.41	$ 1.41	
			75	$ -		75	$ -	$ -	
			75	$ -		75	$ -	$ -	
Sub-Total A (excluding pass through)				$ 461.45			$ 380.69	**-$ 80.76**	**-17.50%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 1.1866	75	-$ 89.00	$ 0.5185	75	$ 38.89	$ 127.88	143.70%
			75	$ -		75	$ -	$ -	
			75	$ -		75	$ -	$ -	
			75	$ -		75	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.1502	75	$ 11.27	$ 0.1439	75	$ 10.79	-$ 0.47	-4.19%
Line Losses on Cost of Power	per kWh	$ 0.0910	3,400.00	$ 309.40	$ 0.0910	3,315.00	$ 301.67	-$ 7.74	-2.50%
Smart Meter Entity Charge		$ 0.7900		$ -	$ 0.7900		$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 693.12**			**$ 732.04**	**$ 38.92**	**5.61%**
RTSR - Network	per kW	$ 2.3783	75	$ 178.37	$ 2.4800	75	$ 186.00	$ 7.63	4.28%
RTSR - Line and Transformation Connection	per kW	$ 1.7325	75	$ 129.94	$ 1.9031	75	$ 142.73	$ 12.80	9.85%
Sub-Total C - Delivery (including Sub-Total B)				**$ 1,001.43**			**$ 1,060.77**	**$ 59.34**	**5.93%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	53400	$ 234.96	$ 0.0044	53315	$ 234.59	-$ 0.37	-0.16%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	53400	$ 64.08	$ 0.0012	53315	$ 63.98	-$ 0.10	-0.16%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	50000	$ 350.00	$ 0.0070	50000	$ 350.00	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0780	600	$ 46.80	$ 0.0780	600	$ 46.80	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0910	49400	$ 4,495.40	$ 0.0910	49400	$ 4,495.40	$ -	0.00%
Total Bill on RPP (before Taxes)				**$ 6,192.92**			**$ 6,251.78**	**$ 58.86**	**0.95%**
HST		13%		$ 805.08	13%		$ 812.73	$ 7.65	0.95%
Total Bill (including HST)				$ 6,998.00			$ 7,064.51	$ 66.51	0.95%
Ontario Clean Energy Benefit [1]								$ -	
Total Bill on RPP (including OCEB)				**$ 6,998.00**			**$ 7,064.51**	**$ 66.51**	**0.95%**
Loss Factor (%)		6.8000%			6.6300%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Appendix 2-W
Bill Impacts

Customer Class: GENERAL SERVICE 50 TO 4,999 KW - "*Former*" INTERVAL METERED (500,000 kWh; 1,000 kW)

TOU / non-TOU: non-TOU

Consumption 500,000 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)
1,000 kW

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 104.0600	1	$ 104.06	$ 84.9800	1	$ 84.98	-$ 19.08	-18.34%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 4.8286	1,000	$ 4,828.60	$ 3.9926	1,000	$ 3,992.60	-$ 836.00	-17.31%
Smart Meter Disposition Rider			1,000	$ -		1,000	$ -	$ -	
LRAM & SSM Rate Rider			1,000	$ -		1,000	$ -	$ -	
Shared Tax Savings Rate Rider	per kW	-$ 0.0271	1,000	-$ 27.10		1,000	$ -	$ 27.10	-100.00%
PILs a/c 1562 Disposition Rate Rider	per kW	-$ 0.1995	1,000	-$ 199.50		1,000	$ -	$ 199.50	-100.00%
Stranded Meter Rate Rider	per kW		1,000	$ -	$ 0.0571	1,000	$ 57.10	$ 57.10	
PPE Adjustment a/c 1576 Rate Rider	per kW		1,000	$ -	-$ 0.1257	1,000	-$ 125.70	-$ 125.70	
REG Investment Rate Funding Adder	per kW		1,000	$ -	$ 0.0188	1,000	$ 18.80	$ 18.80	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 4,706.06			$ 4,027.78	**-$ 678.28**	**-14.41%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 1.1866	1,000	-$ 1,186.60	$ 0.5185	1,000	$ 518.50	$ 1,705.10	143.70%
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.1502	1,000	$ 150.20	$ 0.1439	1,000	$ 143.90	-$ 6.30	-4.19%
Line Losses on Cost of Power	per kWh	$ 0.0910	34,000	$ 3,094.00	$ 0.0910	33,150	$ 3,016.65	-$ 77.35	-2.50%
Smart Meter Entity Charge		$ 0.7900		$ -	$ 0.7900		$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 6,763.66**			**$ 7,706.83**	**$ 943.17**	**13.94%**
RTSR - Network	per kW	$ 2.5228	1000	$ 2,522.80	$ 2.4800	1000	$ 2,480.00	-$ 42.80	-1.70%
RTSR - Line and Transformation Connection	per kW	$ 1.9149	1000	$ 1,914.90	$ 1.9031	1000	$ 1,903.10	-$ 11.80	-0.62%
Sub-Total C - Delivery (including Sub-Total B)				**$ 11,201.36**			**$ 12,089.93**	**$ 888.57**	**7.93%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	534000	$ 2,349.60	$ 0.0044	533150	$ 2,345.86	-$ 3.74	-0.16%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	534000	$ 640.80	$ 0.0012	533150	$ 639.78	-$ 1.02	-0.16%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	500000	$ 3,500.00	$ 0.0070	500000	$ 3,500.00	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0780	600	$ 46.80	$ 0.0780	600	$ 46.80	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0910	499400	$ 45,445.40	$ 0.0910	499400	$ 45,445.40	$ -	0.00%
Total Bill on RPP (before Taxes)				**$ 63,184.21**			**$ 64,068.02**	**$ 883.81**	**1.40%**
HST		13%		$ 8,213.95	13%		$ 8,328.84	$ 114.90	1.40%
Total Bill (including HST)				$ 71,398.16			$ 72,396.86	$ 998.71	1.40%
Ontario Clean Energy Benefit [1]								$ -	
Total Bill on RPP (including OCEB)				**$ 71,398.16**			**$ 72,396.86**	**$ 998.71**	**1.40%**
Loss Factor (%)		6.8000%			6.6300%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

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Appendix 2-W
Bill Impacts

Customer Class: UNMETERED SCATTERED LOAD (500 kWh)

TOU / non-TOU: non-TOU

Consumption 500 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 20.8300	1	$ 20.83	$ 20.8700	1	$ 20.87	$ 0.04	0.19%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0027	500	$ 1.35	$ 0.0027	500	$ 1.35	$ -	0.00%
Smart Meter Disposition Rider			500	$ -		500	$ -	$ -	
LRAM & SSM Rate Rider			500	$ -		500	$ -	$ -	
Shared Tax Savings Rate Rider	per kWh	-$ 0.0002	500	-$ 0.10		500	$ -	$ 0.10	-100.00%
PILs a/c 1562 Disposition Rate Rider	per kWh	-$ 0.0016	500	-$ 0.80		500	$ -	$ 0.80	-100.00%
PPE Adjustment a/c 1576 Rate Rider	per kWh		500	$ -	-$ 0.0015	500	-$ 0.75	-$ 0.75	
REG Investment Rate Funding Adder	per kWh		500	$ -	$ 0.0002	500	$ 0.10	$ 0.10	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Sub-Total A (excluding pass through)				$ 21.28			$ 21.57	**$ 0.29**	**1.36%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0025	500	-$ 1.25	-$ 0.0003	500	-$ 0.15	$ 1.10	88.00%
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0003	500	$ 0.15	$ 0.0004	500	$ 0.20	$ 0.05	33.33%
Line Losses on Cost of Power	per kWh	$ 0.0780	34.00	$ 2.65	$ 0.0780	33.15	$ 2.59	-$ 0.07	-2.50%
Smart Meter Entity Charge		$ 0.7900		$ -	$ 0.7900		$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 22.83**			**$ 24.21**	**$ 1.37**	**6.02%**
RTSR - Network	per kWh	$ 0.0058	534	$ 3.10	$ 0.0058	533	$ 3.09	-$ 0.00	-0.16%
RTSR - Line and Transformation Connection	per kWh	$ 0.0044	534	$ 2.35	$ 0.0045	533	$ 2.40	$ 0.05	2.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 28.28**			**$ 29.70**	**$ 1.42**	**5.02%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	534	$ 2.35	$ 0.0044	533	$ 2.35	-$ 0.00	-0.16%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	534	$ 0.64	$ 0.0012	533	$ 0.64	-$ 0.00	-0.16%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	500	$ 3.50	$ 0.0070	500	$ 3.50	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0780	500	$ 39.00	$ 0.0780	500	$ 39.00	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0910	0	$ -	$ 0.0910	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 74.02**			**$ 75.43**	**$ 1.41**	**1.91%**
HST		13%		$ 9.62	13%		$ 9.81	$ 0.18	1.91%
Total Bill (including HST)				$ 83.64			$ 85.24	$ 1.60	1.91%
Ontario Clean Energy Benefit [1]				-$ 8.36			-$ 8.52	-$ 0.16	1.91%
Total Bill on TOU (including OCEB)				**$ 75.28**			**$ 76.72**	**$ 1.44**	**1.91%**
Loss Factor (%)		6.8000%			6.6300%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

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Appendix 2-W
Bill Impacts

Customer Class: SENTINEL LIGHTING (77 kWh; 0.21 kW)

TOU / non-TOU: non-TOU

Consumption 77 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

0.21 kW

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 12.9900	1	$ 12.99	$ 14.1400	1	$ 14.14	$ 1.15	8.85%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 33.5294	0.21	$ 7.04	$ 36.4943	0.21	$ 7.66	$ 0.62	8.84%
Smart Meter Disposition Rider			0.21	$ -		0.21	$ -	$ -	
LRAM & SSM Rate Rider			0.21	$ -		0.21	$ -	$ -	
Shared Tax Savings Rate Rider	per kW	-$ 0.5613	0.21	-$ 0.12		0.21	$ -	$ 0.12	-100.00%
PILs a/c 1562 Disposition Rate Rider	per kW	-$ 2.2663	0.21	-$ 0.48		0.21	$ -	$ 0.48	-100.00%
PPE Adjustment a/c 1576 Rate Rider	per kW		0.21	$ -	-$ 3.9156	0.21	-$ 0.82	-$ 0.82	
REG Investment Rate Funding Adder	per kW		0.21	$ -	$ 0.5553	0.21	$ 0.12	$ 0.12	
			0.21	$ -		0.21	$ -	$ -	
			0.21	$ -		0.21	$ -	$ -	
			0.21	$ -		0.21	$ -	$ -	
Sub-Total A (excluding pass through)				$ 19.44			$ 21.10	**$ 1.66**	**8.54%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 1.3863	0.21	-$ 0.29	$ 5.9957	0.21	$ 1.26	$ 1.55	532.50%
			0.21	$ -		0.21	$ -	$ -	
			0.21	$ -		0.21	$ -	$ -	
			0.21	$ -		0.21	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.1103	0.21	$ 0.02	$ 0.1210	0.21	$ 0.03	$ 0.00	9.70%
Line Losses on Cost of Power	per kWh	$ 0.0780	5.24	$ 0.41	$ 0.0780	5.11	$ 0.40	-$ 0.01	-2.50%
Smart Meter Entity Charge		$ 0.7900		$ -	$ 0.7900		$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 19.58**			**$ 22.78**	**$ 3.20**	**16.36%**
RTSR - Network	per kW	$ 1.8025	0.21	$ 0.38	$ 1.8003	0.21	$ 0.38	-$ 0.00	-0.12%
RTSR - Line and Transformation Connection	per kW	$ 1.3675	0.21	$ 0.29	$ 1.3957	0.21	$ 0.29	$ 0.01	2.06%
Sub-Total C - Delivery (including Sub-Total B)				**$ 20.24**			**$ 23.45**	**$ 3.21**	**15.85%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	82	$ 0.36	$ 0.0044	82	$ 0.36	-$ 0.00	-0.16%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	82	$ 0.10	$ 0.0012	82	$ 0.10	-$ 0.00	-0.16%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	77	$ 0.54	$ 0.0070	77	$ 0.54	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0780	77	$ 6.01	$ 0.0780	77	$ 6.01	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0910	0	$ -	$ 0.0910	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 27.50**			**$ 30.71**	**$ 3.21**	**11.66%**
HST		13%		$ 3.57	13%		$ 3.99	$ 0.42	11.66%
Total Bill (including HST)				$ 31.07			$ 34.70	$ 3.62	11.66%
Ontario Clean Energy Benefit [1]				-$ 3.11			-$ 3.47	-$ 0.36	11.58%
Total Bill on TOU (including OCEB)				**$ 27.96**			**$ 31.23**	**$ 3.26**	**11.67%**
Loss Factor (%)		6.8000%			6.6300%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

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Appendix 2-W
Bill Impacts

Customer Class: **STREET LIGHTING (170,000 kWh; 550 kW)**

TOU / non-TOU: non-TOU

Consumption 170,000 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)
550.00 kW

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 6.0900	2973	$ 18,105.57	$ 6.1000	2973	$ 18,135.30	$ 29.73	0.16%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 15.5853	550.00	$ 8,571.92	$ 15.6168	550.00	$ 8,589.24	$ 17.32	0.20%
Smart Meter Disposition Rider			550.00	$ -		550.00	$ -	$ -	
LRAM & SSM Rate Rider			550.00	$ -		550.00	$ -	$ -	
Shared Tax Savings Rate Rider	per kW	-$ 0.2405	550.00	-$ 132.28		550.00	$ -	$ 132.28	-100.00%
PILs a/c 1562 Disposition Rate Rider	per kW	-$ 1.0803	550.00	-$ 594.17		550.00	$ -	$ 594.17	-100.00%
PPE Adjustment a/c 1576 Rate Rider	per kW		550.00	$ -	-$ 1.4566	550.00	-$ 801.13	-$ 801.13	
REG Investment Rate Funding Adder	per kW		550.00	$ -	$ 0.2194	550.00	$ 120.67	$ 120.67	
			550.00	$ -		550.00	$ -	$ -	
			550.00	$ -		550.00	$ -	$ -	
			550.00	$ -		550.00	$ -	$ -	
Sub-Total A (excluding pass through)				$ 25,951.05			$ 26,044.08	**$ 93.03**	**0.36%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 1.6598	550.00	-$ 912.89	-$ 0.0569	550.00	-$ 31.30	$ 881.60	96.57%
			550.00	$ -		550.00	$ -	$ -	
			550.00	$ -		550.00	$ -	$ -	
			550.00	$ -		550.00	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.1081	550.00	$ 59.46	$ 0.1115	550.00	$ 61.33	$ 1.87	3.15%
Line Losses on Cost of Power	per kWh	$ 0.0910	11,560.00	$ 1,051.96	$ 0.0910	11,271.00	$ 1,025.66	-$ 26.30	-2.50%
Smart Meter Entity Charge		$ 0.7900		$ -	$ 0.7900		$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 26,149.57**			**$ 27,099.77**	**$ 950.20**	**3.63%**
RTSR - Network	per kW	$ 1.7934	550	$ 986.37	$ 1.7912	550	$ 985.16	-$ 1.21	-0.12%
RTSR - Line and Transformation Connection	per kW	$ 1.3395	550	$ 736.73	$ 1.3671	550	$ 751.91	$ 15.18	2.06%
Sub-Total C - Delivery (including Sub-Total B)				**$ 27,872.67**			**$ 28,836.84**	**$ 964.17**	**3.46%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	181560	$ 798.86	$ 0.0044	181271	$ 797.59	-$ 1.27	-0.16%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	181560	$ 217.87	$ 0.0012	181271	$ 217.53	-$ 0.35	-0.16%
Standard Supply Service Charge	Monthly	$ 0.2500	2973	$ 743.25	$ 0.2500	2973	$ 743.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	170000	$ 1,190.00	$ 0.0070	170000	$ 1,190.00	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0780	600	$ 46.80	$ 0.0780	600	$ 46.80	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0910	169400	$ 15,415.40	$ 0.0910	169400	$ 15,415.40	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 46,284.85**			**$ 47,247.40**	**$ 962.55**	**2.08%**
HST		13%		$ 6,017.03	13%		$ 6,142.16	$ 125.13	2.08%
Total Bill (including HST)				$ 52,301.88			$ 53,389.57	$ 1,087.68	2.08%
Ontario Clean Energy Benefit [1]								$ -	
Total Bill on TOU (including OCEB)				**$ 52,301.88**			**$ 53,389.57**	**$ 1,087.68**	**2.08%**
Loss Factor (%)		6.8000%			6.6300%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

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Appendix 2-W
Bill Impacts

Customer Class: **EMBEDDED DISTRIBUTOR - HYDRO ONE NETWORKS INC.**

TOU / non-TOU: non-TOU

Consumption 6,055,000 kWh ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)
18,970.00 kW

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 184.3200	1	$ 184.32	$ 478.0400	1	$ 478.04	$ 293.72	159.35%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 0.5680	18,970.00	$ 10,774.96	$ 1.4731	18,970.00	$ 27,944.71	$ 17,169.75	159.35%
Smart Meter Disposition Rider			18,970.00	$ -		18,970.00	$ -	$ -	
LRAM & SSM Rate Rider			18,970.00	$ -		18,970.00	$ -	$ -	
			18,970.00	$ -		18,970.00	$ -	$ -	
			18,970.00	$ -		18,970.00	$ -	$ -	
			18,970.00	$ -		18,970.00	$ -	$ -	
			18,970.00	$ -		18,970.00	$ -	$ -	
			18,970.00	$ -		18,970.00	$ -	$ -	
			18,970.00	$ -		18,970.00	$ -	$ -	
Sub-Total A (excluding pass through)				$ 10,959.28			$ 28,422.75	**$ 17,463.47**	**159.35%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.5405	18,970.00	-$ 10,253.29	$ 0.5264	18,970.00	$ 9,985.81	$ 20,239.09	197.39%
			18,970.00	$ -		18,970.00	$ -	$ -	
			18,970.00	$ -		18,970.00	$ -	$ -	
			18,970.00	$ -		18,970.00	$ -	$ -	
Low Voltage Service Charge	per kW		18,970.00	$ -		18,970.00	$ -	$ -	
Line Losses on Cost of Power	per kWh	$ 0.0910	184,677.50	$ 16,805.65	$ 0.0910	174,384.00	$ 15,868.94	-$ 936.71	-5.57%
Smart Meter Entity Charge		$ 0.7900		$ -	$ 0.7900		$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 17,511.65**			**$ 54,277.50**	**$ 36,765.85**	**209.95%**
RTSR - Network	per kW	$ 2.5638	19549	$ 50,118.66	$ 2.8960	19516	$ 56,519.31	$ 6,400.65	12.77%
RTSR - Line and Transformation Connection	per kW	$ 2.3365	19549	$ 45,675.27	$ 2.3898	19516	$ 46,640.14	$ 964.87	2.11%
Sub-Total C - Delivery (including Sub-Total B)				##########			**$ 157,436.95**	**$ 44,131.37**	**38.95%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	6239678	$ 27,454.58	$ 0.0044	6229384	$ 27,409.29	-$ 45.29	-0.16%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	6239678	$ 7,487.61	$ 0.0012	6229384	$ 7,475.26	-$ 12.35	-0.16%
Standard Supply Service Charge	Monthly	$ 0.2500	2973	$ 743.25	$ 0.2500	2973	$ 743.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	6055000	$ 42,385.00	$ 0.0070	6055000	$ 42,385.00	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0780	600	$ 46.80	$ 0.0780	600	$ 46.80	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0910	6054400	##########	$ 0.0910	6054400	$ 550,950.40	$ -	0.00%
Total Bill on TOU (before Taxes)				##########			**$ 786,446.95**	**$ 44,073.73**	**5.94%**
HST		13%		$ 96,508.52	13%		$ 102,238.10	$ 5,729.58	5.94%
Total Bill (including HST)				##########			$ 888,685.05	$ 49,803.31	5.94%
Ontario Clean Energy Benefit [1]								$ -	
Total Bill on TOU (including OCEB)				##########			**$ 888,685.05**	**$ 49,803.31**	**5.94%**
Loss Factor (%)		3.0500%			2.8800%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Exhibit 9 – Deferral and Variance Accounts

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Exhibit 9 – Deferral and Variance Accounts

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OVERVIEW OF DEFERRAL AND VARIANCE ACCOUNTS

OVERVIEW

The information contained in this Exhibit includes the status and description of HCHI's deferral and variance accounts ("DVAs"), the proposed disposition of certain account balances, and the rate riders requested for recovery or refund of those account balances.

HCHI has not made any adjustments to the DVA balances previously approved by the Board on a final basis. However, HCHI has entered adjustment amounts into the "Adjustments During 2012 - Other" column in the OEB's 2014 Electricity Distributors' Deferral and Variance Account Review ("EDDVAR") Excel model in order to appropriately and accurately calculate the total amount being claimed for recovery and the corresponding rate riders being requested in this Application. These adjustments are discussed throughout this Exhibit when relevant to the specific DVA being requested for disposition.

HCHI accounts for the retail settlement variances ("RSVA") specific to its Embedded Distributor – Hydro One Networks Inc. ("HONI") separately from the retail settlement variances on account of its regular customer classes. Accordingly, and consistent with HCHI's 3rd Generation Incentive Rate Mechanism ("IRM") rate applications, including its 2011 IRM3, 2012 IRM3, and 2013 IRM3 rate applications, HCHI was required to use two 2014 EDDVAR models to complete two separate DVA continuity schedules in order to report separately the account balances and to calculate the associated rate riders between its regular customer rate classes and the Embedded Distributor – HONI rate class.

HCHI has submitted two OEB Excel models, "Haldimand_2014 EDDVAR Continuity Schedule COS v2.2", included as Appendix A, for all of its regular customer rate classes

and "Haldimand_2014 EDDVAR Continuity Schedule COS v2.2_HONI", included as Appendix B, for its Embedded Distributor – HONI rate class.

Table 1 provides a summary of all proposed DVA rate riders / funding adders as part of this Application that are discussed and described in more detail throughout this Exhibit.

Table 1
Summary of Proposed DVA Rate Riders and REG Funding Adder

CUSTOMER CLASS	Billing Determinant	Deferral & Variance Rate Rider	Global Adjustment Rate Rider	PP&E Adjustment Rate Rider	Stranded Meter Rate Rider	REG Funding Adder
		(1 year)	(1 year)	(5 year)	(1 year)	(5 year)
Residential	kWh	$ (0.0014)	$ 0.0042	$ (0.0016)	$ 0.0021	$ 0.0002
General Service Less Than 50 kW	kWh	$ (0.0020)	$ 0.0042	$ (0.0010)	$ 0.0019	$ 0.0001
General Service 50 to 4,999 kW	kW	$ (0.9630)	$ 1.4815	$ (0.1257)	$ 0.0571	$ 0.0188
Street Lighting	kW	$ (1.5513)	$ 1.4944	$ (1.4566)		$ 0.2194
Sentinel Lighting	kW	$ 5.9957	$ 1.4975	$ (3.9156)		$ 0.5553
Unmetered Scattered Load	kWh	$ (0.0003)	$ 0.0042	$ (0.0015)		$ 0.0002
Embedded Distributor - Hydro One	kW	$ 0.5729	$ (0.0465)			

ENERGY SALES AND COST OF POWER

Table 2 below provides a breakdown of energy sales and cost of power expense balances, reconciled to HCHI's Audited Financial Statements, for each of the 2010, 2011, and 2012 Actuals.

HCHI confirms that the Independent Electricity System Operator (the "IESO") Global Adjustment Charge has been allocated appropriately to Regulated Price Plan ("RPP") and non-RPP portions.

Table 2
Energy Sales and Cost of Power Reconciliation

Account Description	2010 Actual	2011 Actual	2012 Actual
Residential Energy Sales	$10,311,176	$11,240,325	$12,420,910
Street Lighting Energy Sales	146,445	160,904	18,911
Sentinel Lighting Energy Sales	23,392	24,430	23,493
General Service Energy Sales	14,716,682	15,832,941	14,102,879
Retailer Revenue	4,362,495	4,816,833	6,216,878
Wholesale Market Service Charges	2,909,386	2,925,537	2,073,930
Transmission Network Charges	2,490,966	2,788,020	2,752,849
Transmission Connection Charges	2,287,906	2,455,299	2,203,297
Low Voltage Charges	191,013	136,552	82,393
Total Revenue Billed	**$37,439,461**	**$40,380,841**	**$39,895,540**
Power	$29,560,190	$32,075,433	$32,783,071
Wholesale Market Service Charges	2,909,386	2,925,537	2,073,930
Network Charges	2,490,966	2,788,020	2,703,951
Connection Charges	2,287,906	2,455,299	2,252,196
Low Voltage Charges	191,013	136,552	82,392
Smart Meter Entity Charges			
Total Cost of Power	**$37,439,461**	**$40,380,841**	**$39,895,540**
Audited Financial Statements	**$37,439,461**	**$40,380,841**	**$39,895,540**

PREVIOUS DEFERRAL AND VARIANCE ACCOUNT DISPOSITION

2013 IRM3 Rate Application (EB-2012-0129)

As part of its Decision and Order for HCHI's 2013 IRM3 rate application (EB-2012-0129) issued April 4, 2013, the Board approved a one year disposition of HCHI's December 31, 2011 Group 1 DVA balances in the amount of $(1,110,346). This included a total principal balance of $(1,207,447) plus carrying charges of $97,101. The approved balances were transferred in 2013 to a sub-account of 1595 "Disposition and Recovery/Refund of Regulatory Balances" in accordance with the Decision and Order with corresponding rate riders effective from May 1, 2013 to April 30, 2104. Table 3 below summarizes the 2013 IRM3 approved Group 1 DVA balances approved for disposition.

Table 3
2013 IRM3 Group 1 DVA Balances Approved for Disposition

	Account Number	Total Claim
Account Description		
Low Voltage Variance Account	1550	$ (31,686)
RSVA - Wholesale Market Service Charge	1580	(640,750)
RSVA - Retail Transmission Network Charge	1584	(74,126)
RSVA - Retail Transmission Connection Charge	1586	(34,994)
RSVA - Power (Excluding Global Adjustment)	1588	(130,037)
RSVA - Power (Global Adjustment Sub-account)	1588	(109,549)
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	(89,204)
Total Filed for Disposition		**$ (1,110,346)**
Board Decision and Order dated April 4, 2013:		
Review and Disposition of Group 1 Deferral and Variance Account Balances Excluding Global Adjustment Sub-Account		$ (1,000,796)
Review and Disposition of Group 1 Deferral and Variance Account Balances - Global Adjustment Sub-Account		(109,550)
Total Approved for Disposition		**$ (1,110,346)**

Table 4 provides the breakdown of the DVA balances approved for disposition between HCHI's regular customer rate classes and its Embedded Distributor – HONI rate class. HCHI accounts for RSVAs separately between these two groups as discussed in the overview section of this Exhibit at Tab 1, Schedule 1.

Table 4
2013 IRM3 Approved Disposition – Regular Customer Rate Classes & Embedded Distributor – HONI

All Regular Customer Classes	**Account Number**	**Total Claim**
Account Description		
Low Voltage Variance Account	1550	$ (31,686)
RSVA - Wholesale Market Service Charge	1580	(553,745)
RSVA - Retail Transmission Network Charge	1584	(48,567)
RSVA - Retail Transmission Connection Charge	1586	(11,809)
RSVA - Power (Excluding Global Adjustment)	1588	(83,266)
RSVA - Power (Global Adjustment Sub-account)	1588	(148,944)
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	(89,204)
Total Approved for Disposition for All Regular Customer Classes	1595	$ (967,221)
Embedded Distributor - Hydro One Networks Inc.	**Account Number**	**Total Claim**
Account Description		C = A + B
RSVA - Wholesale Market Service Charge	1580	$ (87,005)
RSVA - Retail Transmission Network Charge	1584	(25,558)
RSVA - Retail Transmission Connection Charge	1586	(23,185)
RSVA - Power (Excluding Global Adjustment)	1588	(46,771)
RSVA - Power (Global Adjustment Sub-account)	1588	39,395
Total Approved for Disposition for Embedded Distributor - Hydro One Networks Inc.	1595	$ (143,125)
Total Approved for Disposition		**$ (1,110,346)**

2012 Smart Meter Cost Recovery Rate Application (EB-2012-0272)

On November 1, 2012, in its Decision and Order in EB-2012-0272, the Board approved disposition of HCHI's smart meter deferral accounts 1555 and 1556 for the recovery of costs related to smart meter deployment offset by smart meter funding adder revenues collected from May 1, 2006 to April 30, 2012. HCHI received approval for Smart Meter Disposition Rate ("SMDR") Riders and Smart Meter Incremental Revenue Requirement ("SMIRR") Rate Riders effective November 1, 2012 to April 30, 2014 for each of the Residential, General Service Less Than 50 kW, and General Service 50 to 4,999 kW customer rate classes.

HCHI transferred the approved balances in the deferral accounts 1555 and 1556 to the appropriate capital ($3,795,629), accumulated depreciation ($762,272), revenue ($1,375,046), and OM&A ($729,190 plus depreciation of $762,272) accounts in 2012. HCHI was approved to leave its Stranded Meters in rate base until its next cost of service. The net book value of these meters will be transferred to a sub-account of 1555 effective December 31, 2013 with a request for disposition and approval of a rate rider in conjunction with the preparation of this Application. This is discussed in further detail in Tab 3, Schedule 1 of this Exhibit.

2012 Payment in Lieu of Taxes Disposition of Account 1562 (EB-2012-0027)

On August 30, 2012, in its Decision and Order in EB-2012-0027, the Board approved HCHI for disposition of Account 1562 "Deferred Payments in Lieu of Taxes" , followed by its Rate Order issued September 27, 2012. The credit balance approved for disposition of $(705,923) included carrying charges of $(106,952) to be disposed of over a 19-month recovery period commencing October 1, 2012 to April 30, 2014. In 2012, the approved balance was transferred to a sub-account of 1595 "Disposition and Recovery/Refund of Regulatory Balances".

DEFERRAL AND VARIANCE ACCOUNT DETAILS

STATUS OF DEFERRAL AND VARIANCE ACCOUNTS

This Schedule contains descriptions of DVAs currently used by HCHI and their balances as at December 31, 2012.

HCHI follows the accrual approach for record keeping and financial reporting for all DVAs, including the RSVA Group 1 accounts.

GROUP 1 ACCOUNTS:

1550 Low Voltage Variance Account

Description: This account is used to record the net difference between the amount billed to customers using the Board Approved Low Voltage rates specific to HCHI and the amounts charged by host distributor(s) to an embedded distributor for transmission or low voltage services.

1580 Retail Settlement Variance Account - Wholesale Market Service Charges

Description: This account is used to record the net difference between the amount billed to customers using the Board Approved Wholesale Market Service Rate, and the amount charged by the IESO based on the settlement invoice for the operation of the IESO-administered markets and the operation of the IESO-controlled grid.

1584 Retail Settlement Variance Account - Retail Transmission Network Charges

Description: This account is used to record the net difference between the amount billed to customers using the Board Approved Transmission Network Charge Rate, and the amount charged by the IESO based on the settlement invoice for transmission network services.

1586 Retail Settlement Variance Account - Retail Transmission Connection Charges

Description: This account is used to record the net difference between the amount billed to customers using the Board Approved Transmission Connection Charge Rate, and the amount charged by the IESO based on the settlement invoice for transmission connection services.

1588 Retail Settlement Variance Account – Power

Description: This account is used to record the net difference between the energy amount billed to customers, and the amount charged by the IESO based on the settlement invoice received from the IESO.

The RSVA-Power account 1588 is designed to capture variances due to billing timing differences (i.e. electricity charged by IESO to LDCs versus electricity billed by LDCs to their customers), price and quantity differences (i.e. arising from final versus preliminary IESO settlement invoices), and line loss differences (i.e. actual versus estimated line loss factors).

1589 Retail Settlement Variance Account – Global Adjustment

Description: This account is used to record the net difference between the global adjustment amount billed to non-RPP customers, and the amount charged by the IESO based on the settlement invoice received from the IESO.

1595 Disposition and Recovery of Regulatory Account Balances

Description: This account is used to record the regulatory asset or liability balances authorized by the Board for disposition through recovery in rates or refunds to customers. Separate sub-accounts are to be maintained for each rate year commencing in 2008 with three further sub-accounts in each year for principal balances to be recovered, carrying charges to be recovered, and the carrying charges calculated on the net principal outstanding.

GROUP 2 ACCOUNTS:

1508 Other Regulatory Assets - Sub-account – Incremental Capital Charges

Description: This account is used to record charges from HONI based on settlement invoices for Incremental Capital charges. An incremental capital module was approved for HONI (EB-2008-0187) effective May 1, 2009 but implemented June 1, 2009.

1518 Retail Settlement Variance Account - Retail

Description: This account is used to recover the net differences between the revenues recovered from Retailer Service Agreements and billing options and the cost of managing the Retailer contracts. This variance is the incremental cost of providing the retail services. The drivers of the costs in this variance are on account of the retail settlement process such as hub services and settlement, and contract administration and monitoring. Table 5 provides revenues and expenses incorporated into Account 1518 for 2012 Actual, 2013 Bridge Year, and 2014 Test Year.

Table 5
Retail Service Charge Variance (1518) – Revenue and Expenses

USoA	Description	2012 Actual	2013 Bridge Year	2014 Test Year
Revenue	**Retail Service Charges**			
4082	Standard Charge	$ (520)	$ (520)	$ (520)
4082	Monthly Fixed Charge	(4,824)	(4,824)	$ (4,924)
4082	Monthly Variable Charge	(13,596)	(13,596)	$ (12,482)
4082	Standard Distributor Consolidated Billing Charge	(7,700)	(7,700)	$ (7,041)
	Total Revenue	**$ (26,639)**	**$ (26,639)**	**$ (24,967)**
Expenses	**Retail Service Charges**			
5340	Retail Settlement Services	$ 78,601	$ 79,622	$ 81,817
5310	Meter Reading	$ 9,990	10,120	$ 15,430
5315	Customer Service Billing	$ 11,570	11,720	$ 10,604
5320	Customer Service Collecting	$ 4,084	4,137	$ 3,662
6005	Bank Charges (Letter of Credit)	$ 1,426	1,445	$ 1,212
6005	Retailer Security Deposit Interest	$ 1,209	1,224	$ 1,380
	Total Expenses	**$ 106,880**	**$ 108,270**	**$ 114,104**
	Total Variance Retail Service Charges	**$ 80,241**	**$ 81,630**	**$ 89,137**

HCHI has followed Article 490 "Accounting for Specific Items – Retail Services and Settlement Variances" in the Board's Accounting Procedures Handbook ("APH") for account 1518.

1531 Renewable Connection Capital Deferral Account

Description: This account is used to record the costs of eligible investments associated with expansions to connect renewable generation facilities and renewable enabling improvements, both as defined in the Distribution System Code.

With this Application, HCHI is requesting approval to record forecast capital renewable connection investments for the period 2015 to 2018 into this account as well as the additional amount requested for provincial recovery for 2013 and 2014 into this account. This is discussed in further detail at Tab 5 of this Exhibit.

1533 Renewable Generation Connection Funding Adder Deferral Account

Description: This account is used to record the revenues collected through a funding adder approved by the Board related to renewable generation connection projects. Separate sub-accounts will be used to record any amounts collected from HCHI's ratepayers and any amounts received from the IESO (pursuant to the provincial pooling mechanism set out in section 79.1 of the *Ontario Energy Board Act, 1998*) in respect of the projects.

With this Application, HCHI is requesting approval for a renewable generation funding adder to be collected from its own customers for forecast capital renewable connection investments for the period 2015 to 2018 and a provincial recovery funding adder collected through the IESO for 2013 through to 2018 forecast investments. This is discussed in further detail at Tab 5, Schedule 4 of this Exhibit.

1548 Retail Settlement Variance Account – Service Transaction Request

Description: This account is used to recover the net differences between the revenues recovered from Service Transaction Requests ("STRs") and the incremental costs of providing these services. The drivers of the costs in this variance are on account of processing services for transaction requests and the initial screening. Table 6 provides revenues and expenses incorporated into Account 1518 for 2012 Actual, 2013 Bridge Year, and 2014 Test Year.

Table 6
Retail STRs Variance (1548) – Revenue and Expenses

USoA	Description	2012 Actual	2013 Bridge Year	2014 Test Year
Revenue Service Transaction Requests				
4084	Retailer STRs	$ (498)	$ (498)	$ (381)
	Total Revenue	**$ (498)**	**$ (498)**	**$ (381)**
Expenses Service Transaction Requests				
5340	Retail Settlement Services	$ 1,604	$ 1,625	$ 1,670
5310	Meter Reading	$ 204	207	315
5315	Customer Service Billing	$ 236	239	216
5320	Customer Service Collecting	$ 83	84	75
6005	Bank Charges (Letter of Credit)	$ 29	29	25
6005	Retailer Security Deposit Interest	$ 25	25	28
	Total Expenses	**$ 2,181**	**$ 2,210**	**$ 2,329**
	Total Variance Service Transaction Requests	**$ 1,683**	**$ 1,712**	**$ 1,948**

HCHI has followed Article 490 "Accounting for Specific Items – Retail Services and Settlement Variances" in the Board's APH for account 1548.

1555 Smart Meter Capital Variance Account – Sub-account Stranded Meters

Description: This account is used to recover the net differences between the gross capital cost and accumulated depreciation of stranded meters. The stranded meter costs are the pooled residual net book value cost of removed meters, less any net sale proceeds when received.

As part of its approved smart meter cost recovery disposition (EB-2012-0272), HCHI was approved to leave its stranded meters in rate base until its next cost of service. HCHI has transferred the cost of its stranded meters, net of accumulated depreciation, in the amount of $483,932 to sub-account 1555 effective December 31. This is discussed in further detail in Tab 3, Schedule 1 of this Exhibit.

1568 Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA")

Description: This account includes the difference between the results of the actual verified impacts of authorized Conservation and Demand Management ("CDM") activities and the level of CDM programs included in the distributor's load forecast.

HCHI's 2010 approved load forecast did not include any level of CDM on account of the Ontario Power Authority's (the "OPA's) 2011 to 2014 programs. Consequently, the full impact of the 2011 programs in 2011 and their persistence into 2012, and the 2012 programs in 2012, has been calculated without any adjustment for CDM savings already included in load forecast. HCHI recorded this cumulative amount into the LRAMVA in 2013 and has also included it in the "Adjustments During 2012 – Other" column in the 2014 EDDVAR Continuity Schedule for inclusion in the total balance of DVAs to be approved for disposition and the appropriate and accurate calculation of rate riders. This is discussed in further detail at Tab 6 of this Exhibit.

1576 Accounting Changes under CGAAP

Description: This account is used to record the financial differences arising as a result of changes to accounting depreciation or capitalization policies permitted by the Board under Canadian Generally Accepted Accounting Principles ("CGAAP") in 2012 or as mandated by the Board in 2013.

HCHI has recorded this accounting change in the amount of $1,459,184 effective January 1, 2013, and included it in the OEB's 2014 EDDVAR Continuity Schedule in the "Adjustments During 2012 – Other" column plus the rate of return in the amount of $419,515 as instructed in the OEB's model on worksheet "2.2013 Continuity Schedule". No carrying charges have been calculated and the balance will be credited to customers through a rate rider over the 5-year term of this Application. This is discussed in further detail at Tab 4, Schedule 1 of this Exhibit.

1592 PILs and Tax Variance for 2006 and Subsequent Years – Sub-account HST/OVAT Input Tax Credits (ITCs)

Description: This account is used to record the incremental ITCs received in distribution Revenue Requirement previously subject to provincial sales tax ("PST") and now subject to harmonized sales tax ("HST"). Reporting of these amounts will continue into this deferral account until April 30, 2014. 50% of the confirmed balance in this account including carrying charges shall be refundable to the ratepayers.

HCHI used the simplified method outlined in the Board's *Frequently Asked Questions* ("FAQs"), issued December 23, 2010, to calculate a detailed one time analysis based on its most recent historic year, 2009, to identify the PST included in capital spending which would have been removed by the elimination of the PST. HCHI uses the transactional method to identify and record the PST included in Operating, Maintenance and Administrative ("OM&A") costs on each accounts payable invoice where PST would have been applicable prior to the implementation of the HST effective July 1, 2010. As an oversight, HCHI had not been recording the incremental ITC on capital expenditures. HCHI has now calculated this amount in conjunction with preparation of this Application and has recorded it in 2013. The "Adjustments During 2012 – Other" column of the 2014 EDDVAR Continuity Schedule includes the incremental ITC on capital

expenditures for the period July 1, 2010 to April 30, 2014 and the forecast incremental ITC on OM&A costs for the period January 1, 2013 to April 30, 2014. HCHI has appropriately reduced this account on the 2014 EDDVAR Continuity Schedule by 50% in order to accurately calculate the applicable rate rider refundable to customers and has shown the contra account at 100% in the section including accounts on a memo basis only. The following Table 7 provides further details of the incremental ITCs recorded in 1592. This information has also been filed as OEB Appendix 2-TB "1592 HST-OVAT".

Table 7
Summary of PST Savings – OM&A and Capital Spending

	Principal 2010	Principal 2011	Principal 2012	Principal 2013	Principal January to April 2014	Carrying Charges to April 30, 2014	Total Account 1592, sub-account HST/OVAT Balance
OM&A Expenses PST Savings	$ 22,308	$ 47,167	$ 39,746	$ 40,119	$ 14,689	$ 4,564	**$ 168,593**
Capital Items PST Savings	$ 12,175	$ 24,350	$ 36,525	$ 48,700	$ 16,233	$ 3,183	**$ 141,166**
Total Annual PST Savings	$ 34,483	$ 71,517	$ 76,271	$ 88,819	$ 30,923	$ 7,747	**$ 309,759**

HCHI did not report the carrying charges associated with account 1592 or with contra account 1592 in the Reporting and Record Keeping Requirements ("RRR") Filings to the Board for December 31 2012 balances and has therefore included it in the "Adjustments During 2012 – Other" column of the 2014 EDDVAR Continuity Schedule.

Upon approved disposition of account 1592, HCHI will cease recording costs into it and its contra account.

DEFERRAL AND VARIANCE ACCOUNT BALANCES

The following Table 8 provides DVA balances as at December 31, 2012. These balances reconcile to those reported (i) in the audited financial statements as at and for the year ended December 31, 2012 and (ii) to the Board in the regulatory trial balance as part of the required RRR filing (as revised) submitted August 20, 2013.

Table 8
DVA Balances as at December 31, 2012

Deferral and Variance Accounts	Account No.	Principal as of Dec. 31/12	Carrying Charges to Dec. 31/12	Total as of Dec. 31/12
RSVA Accounts				
Low Voltage	1550	$ (52,011)	$ (733)	$ (52,744)
Wholesale Market Service Charge	1580	$(1,367,378)	$ (18,841)	$(1,386,219)
Retail Transmission Network Charge	1584	$ (45,941)	$ (506)	$ (46,447)
Retail Transmission Connection Charge	1586	$ (39,271)	$ 222	$ (39,050)
Power	1588	$ (203,291)	$ (4,016)	$ (207,307)
Global Adjustment	1589	$ 490,764	$ (1,106)	$ 489,658
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	$ (203,915)	$ 115,889	$ (88,026)
Disposition and Recovery/Refund of Regulatory Balances (2011)	1595	$ 26,820	$ (12,111)	$ 14,709
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	$ (971,919)	$ (151,921)	$(1,123,841)
Sub-total RSVA Accounts		$(1,394,224)	$ 78,798	$(1,315,426)
Non RSVA Accounts				
Other Regulatory Assets - Incremental Capital Charges	1508	$ 5,939	$ 229	$ 6,168
Retail Cost Variance Account - Retail	1518	$ 317,018	$ 8,133	$ 325,151
Retail Cost Variance Account - STR	1548	$ 5,967	$ 151	$ 6,118
Smart Meter Capital - Stranded Meters	1555	$ (4,491)	$ -	$ (4,491)
PILs and Tax Variance Sub-account - HST/OVAT Input Tax Credits (ITCs)	1592	$ (109,221)	$ -	$ (109,221)
PILs and Tax Variance Sub-account - HST/OVAT Input Tax Credits - Contra	1592	$ 109,221	$ -	$ 109,221
Sub-total Non RSVA Accounts		$ 324,432	$ 8,514	$ 332,946
Total Deferral & Variance Accounts		$(1,069,792)	$ 87,312	$ (982,480)

DVA balances include carrying charges which are calculated using simple interest applied to the monthly opening balance less any accumulated carrying charges in the account. HCHI follows the accrual approach for record keeping and financial reporting and follows the same approach when calculating carrying charges. Interest rates used by HCHI to record carrying charges are consistent with the Board's prescribed rates for the respective quarterly period, as provided in Table 9 below.

Table 9
Prescribed Interest Rates for Deferral and Variance Accounts

	2009	2010	2011	2012	2013	2014
January	2.45%	0.55%	1.47%	1.47%	1.47%	1.47%
February	2.45%	0.55%	1.47%	1.47%	1.47%	1.47%
March	2.45%	0.55%	1.47%	1.47%	1.47%	1.47%
April	1.00%	0.55%	1.47%	1.47%	1.47%	1.47%
May	1.00%	0.55%	1.47%	1.47%	1.47%	
June	1.00%	0.55%	1.47%	1.47%	1.47%	
July	0.55%	0.89%	1.47%	1.47%	1.47%	
August	0.55%	0.89%	1.47%	1.47%	1.47%	
September	0.55%	0.89%	1.47%	1.47%	1.47%	*(Note: 1)*
October	0.55%	1.20%	1.47%	1.47%	1.47%	
November	0.55%	1.20%	1.47%	1.47%	1.47%	
December	0.55%	1.20%	1.47%	1.47%	1.47%	
Note: 1	At the time of filing, the last quarterly interest rate published by the Board was on September 17, 2013 for Q4 2013. This rate has been applied to the forecasted carrying charges calculated to the rate implementation date of May 1, 2014.					

ACCOUNTS REQUESTED FOR DISPOSITION BY WAY OF A DEFERRAL AND VARIANCE ACCOUNT RATE RIDER

Appendix A "2014 EDDVAR Continuity Schedule – All Regular Customer Classes" and Appendix B "2014 EDDVAR Continuity Schedule – Embedded Distributor Hydro One Networks Inc." provide the DVA balance continuity schedules for the period January 1, 2009 to December 31, 2012, itemizing opening balances, annual adjustments, accruals, carrying charges and closing balances. It also provides the projected carrying charges for each DVA calculated to the proposed rate rider implementation date of May 1, 2014.

The opening principal and carrying charge balances as of January 1, 2009 represent the last Board Approved balances as of December 31, 2008. These balances were approved by the Board as part of HCHI's 2010 COS rate application (EB-2009-0265) and have been transferred to Account 1595 as required effective May 1, 2010.

In a letter dated February 19, 2008, the Board initiated a process – Board file no. EB-2008-0046 – to review the EDDVAR. On April 1, 2009 Board staff issued a discussion paper entitled "*Board Staff Discussion Paper on Electricity Distributors' Deferral and Variance Account Review*" for stakeholder comment. On July 31, 2009 the Board issued its "*Report on Electricity Distributors' Deferral and Variance Account Review Initiative*" ("Board Report"), which sets out the Board's policy for the annual review and disposition of deferral and variance accounts in a rebasing year, including filing guidelines.

In accordance with the Board Report, HCHI is requesting the disposition of the following DVAs as set out in Table 10, which include the closing principal and carrying charges as of December 31, 2012 and the projected carrying charges from January 1, 2013 to April 30, 2014 calculated on the closing principal balance as of December 31, 2012. The projected carrying charges have been calculated using the prescribed interest rates as noted in Table 6 above. All DVA balances requested for disposition reconcile to HCHI's

Audited Financial Statements for the year ended December 31, 2012 and to the RRR Trial Balance filing 2.1.7 for 2012 with the exception of accounts 1568, 1576, 1592, 1592 contra, and 1595. The differences have been noted above in Tab 2, Schedule 1 under each specific account as well as explained on sheet "3.Appendix A" of the OEB's 2014 EDDVAR Continuity Schedule provided in Appendix A to this Exhibit.

Further to the Board Report, the Board agrees that at the time of rebasing, all DVA balances should be disposed of unless otherwise justified by the distributor or as required by a specific Board decision or guideline.

HCHI is also requesting disposition of its Sub-account 1555 - Smart Meter Capital – Stranded Meters balance in conjunction with this Application. Details of the balance requested for disposition and the rate rider calculation are provided in Tab 3, Schedule 1 of this Exhibit.

Table 10
DVAs Requested For Disposition

Deferral and Variance Accounts	Account No.	Principal & Carrying Charges as at Dec. 31, 2012	Carrying Charges Projected 2013 and 2014	Total Claim	Principal & Carrying Charges as at Dec. 31, 2012	Carrying Charges Projected 2013 and 2014	Total Claim	**Principal & Carrying Charges as at Dec. 31, 2012**	**Carrying Charges Projected 2013 and 2014**	**Total Claim**
Group 1 Accounts										
Low Voltage Charges	1550	$ (21,058)	$ (407)	$ (21,465)	$ -	$ -	$ -	**$ (21,058)**	**$ (407)**	**$ (21,465)**
Wholesale Market Service Charge	1580	$ (625,365)	$ (12,175)	$ (637,540)	$ (120,104)	$ (2,336)	$ (122,440)	**$ (745,469)**	**$ (14,511)**	**$ (759,980)**
Retail Transmission Network Charge	1584	$ (111,382)	$ (2,176)	$ (113,558)	$ 139,060	$ 2,703	$ 141,763	**$ 27,678**	**$ 527**	**$ 28,205**
Retail Transmission Connection Charge	1586	$ (94,329)	$ (1,821)	$ (96,150)	$ 90,273	$ 1,756	$ 92,029	**$ (4,056)**	**$ (65)**	**$ (4,121)**
Power	1588	$ (60,479)	$ (1,200)	$ (61,679)	$ (16,791)	$ (323)	$ (17,114)	**$ (77,270)**	**$ (1,523)**	**$ (78,793)**
Global Adjustment	1589	$ 609,609	$ 11,977	$ 621,586	$ (10,402)	$ (187)	$ (10,589)	**$ 599,207**	**$ 11,790**	**$ 610,997**
Disposition and Recovery/Refund of Regulatory Balances	1595	$ (20,995)	$ (15)	$ (21,010)	$ 35,672	$ 540	$ 36,212	**$ 14,677**	**$ 525**	**$ 15,202**
Total Group 1 Accounts		$ (323,998)	$ (5,818)	$ (329,816)	$ 117,708	$ 2,153	$ 119,861	**$ (206,290)**	**$ (3,665)**	**$ (209,955)**
Group 2 Accounts										
Other Regulatory Assets - Incremental Capital Charges	1508	$ 6,168	$ 116	$ 6,285	$ -	$ -	$ -	**$ 6,168**	**$ 116**	**$ 6,285**
Retail Cost Variance Account - Retail	1518	$ 325,151	$ 6,214	$ 331,365	$ -	$ -	$ -	**$ 325,151**	**$ 6,214**	**$ 331,365**
Retail Cost Variance Account - STR	1548	$ 6,118	$ 117	$ 6,235	$ -	$ -	$ -	**$ 6,118**	**$ 117**	**$ 6,235**
Total Group 2 Accounts		$ 337,438	$ 6,447	$ 343,885	$ -	$ -	$ -	**$ 337,438**	**$ 6,447**	**$ 343,885**
Other Accounts										
LRAM Variance Account	1568	$ 82,207	$ 1,611	$ 83,818	$ -	$ -	$ -	**$ 82,207**	**$ 1,611**	**$ 83,818**
Accounting Changes Under CGAAP - Balance plus Return Component	1576	$ (1,878,699)	$ -	$(1,878,699)	$ -	$ -	$ -	**$ (1,878,699)**	**$ -**	**$ (1,878,699)**
PILs and Tax Variance Sub-account - HST/OVAT Input Tax Credits (50%)	1592	$ (152,541)	$ (2,339)	$ (154,880)	$ -	$ -	$ -	**$ (152,541)**	**$ (2,339)**	**$ (154,880)**
Total Other Accounts		$ (1,949,033)	$ (727)	$(1,949,760)	$ -	$ -	$ -	**$ (1,949,033)**	**$ (727)**	**$ (1,949,760)**
Total Deferral & Variance Accounts Request for Disposition		$ (1,935,593)	$ (99)	$(1,935,692)	$ 117,708	$ 2,153	$ 119,861	**$ (1,817,885)**	**$ 2,054**	**$ (1,815,831)**

METHOD OF DISPOSITION

Allocators

The following Table 11 provides the 2014 load forecast data by customer rate class and the associated allocators.

Table 11
2014 Load Forecast Data and Allocators

2014 FORECAST DATA BY CLASS	kW	kWh	kWh (Non - RPP Customers)	Distribution Revenue	Number of Customers/ Connections	kW (Non - RPP Customers)
Residential	-	169,003,519	19,798,762	$ 8,892,831	18,772	-
General Service < 50 kW	-	53,925,141	14,624,498	1,711,607	2,363	-
General Service 50 to 4999 kW	342,324	121,879,907	112,480,529	1,430,482	153	315,924
Street Lighting	6,648	2,387,575	2,357,133	118,345	3	6,563
Sentinel Lighting	909	327,143	53,131	321,966	502	148
Unmetered Scattered Load		350,238	67,176	17,974	68	
Total	**349,881**	**347,873,523**	**149,381,229**	**$ 12,493,205**	**21,861**	**322,635**

ALLOCATORS	kW	kWh	kWh (Non - RPP Customers)	Distribution Revenue	Number of Customers/ Connections	
Residential	0.00%	48.58%	13.25%	71.18%	85.87%	
General Service < 50 kW	0.00%	15.50%	9.79%	13.70%	10.81%	
General Service 50 to 4999 kW	97.84%	35.04%	75.30%	11.45%	0.70%	
Street Lighting	1.90%	0.69%	1.58%	0.95%	0.01%	
Sentinel Lighting	0.26%	0.09%	0.04%	2.58%	2.30%	
Unmetered Scattered Load	0.00%	0.10%	0.04%	0.14%	0.31%	
Total	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	

Embedded Distributor - Hydro One Networks Inc.	227,715	72,629,941	72,629,941	$ 381,346	8	227,715

In accordance with the Board Report, the DVA balances claimed for disposition (refer to Table 8) are allocated to the customer rate classes based on the default allocation factors as approved by the Board.

The following Table 12 provides the LRAMVA amounts plus carrying charges allocated by customer rate class as calculated in the LRAMVA model prepared by IndEco

Strategic Consulting Inc. ("IndEco") on HCHI's behalf. Further details can be found in Tab 6 of this Exhibit.

Table 12
LRAMVA Balances and Allocation

	LRAMVA		
RATE CLASS	**Amounts (2011 and 2012)**	**Carrying Charges**	**LRAMVA Total**
Residential	$ 39,804	$ 780	$ 40,584
General Service Less Than 50 kW	$ 24,416	$ 479	$ 24,895
General Service 50 to 4,999 kW	$ 17,987	$ 353	$ 18,340
Total	**$ 82,207**	**$ 1,611**	**$ 83,818**

Calculation of Rate Riders

As required, a volumetric rate rider has been applied to dispose of the DVA balances reported in Table 10 over the default disposition period of one year for all accounts except Account 1576 – Accounting Changes under CGAAP. This account is requested for disposal over the 5 year rate term and has a separate rate rider calculated. All rate riders will have an implementation date of May 1, 2014, which is concurrent with the implementation of the distribution rate changes. The derivation of the deferral and variance account rate riders is provided in the following Table 13 for regular customer rate classes and Table 14 for the Embedded Distributor – HONI. Table 15 provides the derivation of the rate riders for Account 1576 – Accounting Changes under CGAAP.

Table 13
Derivation of DVA Rate Riders – All Regular Customer Classes

DEFERRAL AND VARIANCE ACCOUNTS	Account No.	Total Claim	Allocation Factor	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
Low Voltage Charges	1550	$ (21,465)	kWh	$ (10,428)	$ (3,327)	$ (7,521)	$ (147)	$ (20)	$ (22)
RSVA - Wholesale Market Service Charge	1580	$ (637,540)	kWh	$ (309,729)	$ (98,827)	$ (223,367)	$ (4,376)	$ (600)	$ (642)
RSVA - Retail Transmission Network Charge	1584	$ (113,558)	kWh	$ (55,169)	$ (17,603)	$ (39,786)	$ (779)	$ (107)	$ (114)
RSVA - Retail Transmission Connection Charge	1586	$ (96,150)	kWh	$ (46,712)	$ (14,905)	$ (33,687)	$ (660)	$ (90)	$ (97)
RSVA - Power	1588	$ (61,679)	kWh	$ (29,965)	$ (9,561)	$ (21,610)	$ (423)	$ (58)	$ (62)
Disposition and Recovery/Refund of Regulatory Balances	1595	$ (21,010)	kWh	$ (10,207)	$ (3,257)	$ (7,361)	$ (144)	$ (20)	$ (21)
Sub-Total - Group 1 Accounts		$ (951,402)		$ (462,210)	$ (147,480)	$ (333,332)	$ (6,529)	$ (895)	$ (958)
Other Regulatory Assets - Incremental Capital Charges	1508	$ 6,285	Dist'n Revenue	$ 4,474	$ 861	$ 720	$ 162	$ 60	$ 9
Retail Cost Variance Account - Retail	1518	$ 331,365	# Customers	$ 284,542	$ 35,818	$ 2,319	$ 45	$ 7,609	$ 1,031
Retail Cost Variance Account - STR	1548	$ 6,235	# Customers	$ 5,354	$ 674	$ 44	$ 1	$ 143	$ 19
Sub-Total - Group 2 Accounts		$ 343,885		$ 294,370	$ 37,353	$ 3,083	$ 208	$ 7,812	$ 1,059
LRAM Variance Account	1568	$ 83,818		$ 40,584	$ 24,895	$ 18,340	$ -	$ -	$ -
PILs and Tax Variance Sub-account - HST/OVAT Input Tax Credits (50%)	1592	$ (154,880)	Dist'n Revenue	$ (110,245)	$ (21,219)	$ (17,734)	$ (3,991)	$ (1,467)	$ (223)
Sub-Total - Other Accounts		$ (71,062)		$ (69,661)	$ 3,676	$ 606	$ (3,991)	$ (1,467)	$ (223)
TOTAL DEFERRAL & VARIANCE ACCOUNTS TO BE RECOVERED (REFUNDED)		**$ (678,579)**		**$ (237,501)**	**$ (106,451)**	**$ (329,643)**	**$ (10,312)**	**$ 5,450**	**$ (122)**
Disposition Period (default) - One Year									
Volumetric Rate Rider - *Billing Determinants*				***kWh***	***kWh***	***kW***	***kW***	***kW***	***kWh***
DEFERRAL AND VARIANCE ACCOUNTS RATE RIDER (Volumetric)				**$ (0.0014)**	**$ (0.0020)**	**$ (0.9630)**	**$ (1.5513)**	**$ 5.9957**	**$ (0.0003)**

DEFERRAL AND VARIANCE ACCOUNTS (Applicable only to Non-RPP Customers)	Account No.	Total Claim	Allocation Factor	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
RSVA - Power - Global Adjustment	1589	$ 621,586	Non-RPP kWh	$ 82,384	$ 60,854	$ 468,039	$ 9,808	$ 221	$ 280
TOTAL DEFERRAL & VARIANCE ACCOUNTS TO BE RECOVERED (REFUNDED)		**$ 621,586**		**$ 82,384**	**$ 60,854**	**$ 468,039**	**$ 9,808**	**$ 221**	**$ 280**
Disposition Period (default) - One Year									
Volumetric Rate Rider - *Billing Determinants*				***kWh***	***kWh***	***kW***	***kW***	***kW***	***kWh***
DEFERRAL AND VARIANCE ACCOUNTS RATE RIDER (Volumetric)				**$ 0.0042**	**$ 0.0042**	**$ 1.4815**	**$ 1.4944**	**$ 1.4975**	**$ 0.0042**

Table 14
Derivation of DVA Rate Riders – Embedded Distributor - HONI

DEFERRAL AND VARIANCE ACCOUNTS	Account No.	Total Claim	Allocation Factor	Embedded Distributor - HONI
RSVA - Wholesale Market Service Charge	1580	$ (122,440)	kWh	$ (122,440)
RSVA - Retail Transmission Network Charge	1584	$ 141,763	kWh	$ 141,763
RSVA - Retail Transmission Connection Charge	1586	$ 92,029	kWh	$ 92,029
RSVA - Power	1588	$ (17,114)	kWh	$ (17,114)
Disposition and Recovery/Refund of Regulatory Balances	1595	$ 36,212	kWh	$ 36,212
TOTAL DEFERRAL & VARIANCE ACCOUNTS TO BE RECOVERED (REFUNDED)		**$ 130,450**		**$ 130,450**
Disposition Period (default) - One Year				
Volumetric Rate Rider - *Billing Determinants*				***kW***
DEFERRAL AND VARIANCE ACCOUNTS RATE RIDER (Volumetric)				**$ 0.5729**
DEFERRAL AND VARIANCE ACCOUNTS (Applicable only to Non-RPP Customers)	**Account No.**	**Total Claim**	**Allocation Factor**	**Embedded Distributor - HONI**
RSVA - Power - Global Adjustment	1589	$ (10,589)	Non-RPP kWh	$ (10,589)
TOTAL DEFERRAL & VARIANCE ACCOUNTS TO BE RECOVERED (REFUNDED)		**$ (10,589)**		**$ (10,589)**
Disposition Period (default) - One Year				
Volumetric Rate Rider - *Billing Determinants*				***kW***
DEFERRAL AND VARIANCE ACCOUNTS RATE RIDER (Volumetric)				**$ (0.0465)**

Table 15
Derivation of DVA Rate Riders – Account 1576 Accounting Changes under CGAAP (PPE Adjustment)

		Property, Plant, & Equipment ("PPE") Adjustment - Account 1576			BILLING UNITS (2014)		RATE RIDER (FIVE YEARS)
RATE CLASS	Distribution Revenue	PPE Adjustment in Account 1576	Rate of Return	Total			PPE Adjustment Rate Rider $ / unit
Residential	71.2%	$ (1,038,667)	$ (298,616)	$ (1,337,283)	169,003,519	kWh	$ (0.0016)
General Service Less Than 50 kW	13.7%	$ (199,912)	$ (57,475)	$ (257,387)	53,925,141	kWh	$ (0.0010)
General Service 50 to 4,999 kW	11.5%	$ (167,078)	$ (48,035)	$ (215,113)	342,324	kW	$ (0.1257)
Street Lighting	2.6%	$ (37,605)	$ (10,811)	$ (48,416)	6,648	kW	$ (1.4566)
Sentinel Lighting	0.9%	$ (13,822)	$ (3,974)	$ (17,796)	909	kW	$ (3.9156)
Unmetered Scattered Load	0.1%	$ (2,099)	$ (604)	$ (2,703)	350,238	kWh	$ (0.0015)
Total	**100.0%**	**$ (1,459,184)**	**$ (419,515)**	**$ (1,878,698)**			

STRANDED ASSETS FROM SMART METER DEPLOYMENT

Stranded Meter Costs

HCHI is seeking disposition of its stranded (i.e. conventional) meter costs in this Application. HCHI continues to recover these costs by including the net book value of stranded meters in Account 1860 and has continued to depreciate these assets over a 25 year period until December 31, 2013. HCHI's smart meter deployment was complete in 2012 and the capital expenditures and OM&A costs recorded in the associated deferral accounts were approved for disposition in its Smart Meter Cost Recovery application, EB-2012-0272, effective November 1, 2012.

HCHI has removed the stranded meter costs from rate base as of December 31, 2013 as part of this Application. There were no capital additions to the stranded meters in 2013. Once the depreciation expense for 2013 was taken on the stranded meters, the net book value of the stranded meters as at December 31, 2013 is $483,933. HCHI has received scrap recoveries, in the amount of $4,491, on account of the disposal of the stranded meters. These proceeds have been allocated to the three customer rate classes of stranded meters based on the net book value of those stranded meters for each rate class resulting in a net balance for disposition of $479,441.

HCHI has transferred the stranded meters net book value to sub-account 1555 "Smart Meter Capital and Recovery Offset" as at December 31, 2013. The scrap recoveries amount related to the disposal of the stranded meters was recorded in this sub-account at time of disposal. The following Table 16 provides details by year of the stranded meter transactions. This same information can be found in OEB Appendix 2-S "Stranded Meters".

Table 16
Stranded Meter Treatment

Year	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
	(A)	(B)	(C)	D) = (A) - (B) - (C	(E)	(F) = (D) - (E)
2006				$ -		$ -
2007				$ -		$ -
2008				$ -		$ -
2009	$ 1,164,668	$ 985,328		$ 179,340		$ 179,340
2010	$ 1,487,164	$ 1,042,811		$ 444,353	$ 3,687	$ 440,666
2011	$ 1,664,167	$ 1,095,973		$ 568,194	$ 3,687	$ 564,508
2012	$ 1,666,572	$ 1,140,139		$ 526,433	$ 4,491	$ 521,942
2013	$ 1,666,572	$ 1,182,640		$ 483,932	$ 4,491	$ 479,441

Stranded Asset Rate Rider Calculation

HCHI is proposing to recover its stranded meter costs over a one year disposition period commencing May 1, 2014, the same date as the distribution rate change. HCHI has tracked its stranded meters by customer rate class based on each customer's original installation date of the conventional meter as stored in its customer information system. This enabled HCHI to calculate the applicable accumulated depreciation associated with each meter resulting in a net book value by customer rate class. The scrap recoveries have been allocated to the customer rate classes based on the net book value of the stranded meters associated with each of these customer rate classes. HCHI is requesting a volumetric rate rider for each customer rate class using the 2014 load forecast information. Table 17 provides the stranded meter rate rider calculations.

Table 17
Stranded Meter Rate Rider

Rate Class	Net Book Value of Stranded Asset	Proceeds on Disposition	Residual Net Book Value	Billing Units (2014)		Rate Rider per unit (one year)
Residential	$ 360,012	$ 3,341	$ 356,671	169,003,519	kWh	$ 0.0021
General Service Less Than 50 kW	$ 104,195	$ 967	$ 103,228	53,925,141	kWh	$ 0.0019
General Service 50 to 4,999 kW	$ 19,725	$ 183	$ 19,542	342,324	kW	$ 0.0571
	$ 483,932	**$ 4,491**	**$ 479,441**			

ACCOUNTING CHANGES UNDER CGAAP

Account 1576 – Accounting Changes under CGAAP

In Exhibit 2, Tab 5, Schedule 5 and Exhibit 4, Tab 3, Schedule 3 of this Application, HCHI identified a change that was applied to the depreciation of its property, plant, and equipment ("PP&E") in 2013, pursuant to the Board's letter dated July 17, 2012 regarding "*Regulatory accounting policy direction regarding changes to depreciation expense and capitalization policies in 2012 and 2013*". As indicated in Table 18 below, the amount of the change required in estimated useful lives results in a reduction in the 2013 closing net PP&E. This same information has been filed as OEB Appendix 2-EE "Account 1576 (2013)".

Table 18
Account 1576 – Accounting Changes under CGAAP

	2013	2014 Rebasing Year	2015	2016	2016	2017
Reporting Basis	**IRM**	**CGAAP - ASPE**	**IRM**	**IRM**	**IRM**	**IRM**
Forecast vs. Actual Used in Rebasing Year	**Forecast**	**Forecast**				
	$	$	$	$	$	$
PP&E Values under former CGAAP						
Opening net PP&E	**41,894,496**					
Net Additions	**3,834,438**					
Net Depreciation (amounts should be negative)	**(2,433,897)**					
Closing net PP&E	**43,295,037**					
PP&E Values under revised CGAAP (Starts from 2013)						
Opening net PP&E	**41,894,496**					
Net Additions	**3,834,438**					
Net Depreciation (amounts should be negative)	**(974,713)**					
Closing net PP&E	**44,754,221**					
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP	**(1,459,184)**					
Effect on Deferral and Variance Account Rate Riders						
Closing balance in Account 1576		**(1,459,184)**		**WACC**	**5.75%**	
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2		**(419,515)**				
Amount included in Deferral and Variance Account Rate Rider Calculation		**(1,878,699)**		**# of years of rate rider disposition period**	**5**	

HCHI has calculated the adjustment to depreciation expense and the cumulative variance credit amount of $1,459,184 has been recorded in account 1576 with an offsetting entry to account 4305 "Regulatory Debit" in 2013.

A rate of return is calculated on this credit based on the weighted average cost of capital in this Application, calculated as 5.75%, subject to updating when final cost of capital parameters are released in early 2014, prior to approval of this Application. This calculated return is $419,515 and has been included in the calculation of the rate rider refund to customers but not recorded in account 1576.

HCHI proposes the rate rider refund to customers be dispersed over the 5-year rate period commencing with rates effective May 1, 2014 with the offsetting entry to depreciation expense in each year. Table 15 in Tab 2, Schedule 4 calculates the rate riders per customer rate class.

RENEWABLE ENERGY GENERATION DEFERRAL ACCOUNTS AND FUNDING ADDER REQUEST

Overview

HCHI has prepared a Renewable Energy Generation ("REG") Plan for the period 2014 to 2018 inclusive, dated August 9, 2013, with subsequent revisions dated August 13, 2013 and October 23, 2013. In accordance with the Board's Filing Requirements, specifically "*Chapter 5 Consolidated Distribution System Plan Filing Requirements*", HCHI submitted its REG plan (revised version dated August 13, 2013) to the OPA for comment. The OPA provided HCHI with a Letter of Comment, dated September 11, 2013. The REG Plan and the OPA's Letter of Comment are included as Appendix C and Appendix D, respectively, of HCHI's Distribution System Plan ("DSP") included as Appendix A to Exhibit 2.

The REG Plan communicates HCHI's intentions regarding the facilitation of connecting renewable generation to its distribution system over the next five years. HCHI has connected 33.9 MW of renewable generation including: (i) Feed-in Tariff ("FIT") contracts, including microFIT and small FIT photo-voltaic ("PV")-solar; s, (ii) Renewable Energy Standard Offer Programs ("RESOPS") including wind and PV-solar; (iii) Net Metering installations, including wind and solar; (iv) clean energy (Natural Gas) projects.

The REG Plan forecasts a continuing stream of FIT and microFIT projects in Haldimand County over the next five years. The annual forecast of distribution connected projects is 50 microFITs, 10 small FITs, and 1 large FIT. The basis for the five year estimate is the available capacity at the Jarvis Transformer Station ("TS") and Caledonia TS, the planned transformer replacements at the Dunnville TS and the anticipated applications based on the large volume of pre-FIT information that has been exchanged with customers over the past several years. Further details of the capital costs related to this forecast renewable generation are provided in HCHI's REG Plan and DSP.

In accordance with the Filing Requirements and section 79.1 of the *Ontario Energy Board Act, 1998* (the "OEB Act") and Regulation 330/09 under the OEB Act, HCHI has allocated the costs of eligible investments for the connection of qualifying generation facilities between its ratepayers (i.e. direct benefit) and all Ontario ratepayers (i.e. provincial recovery). HCHI has assumed the direct benefit percentages to be 17% for REG expansion investments and 6% for REG enabling improvement investments.

The forecast capital costs, in the amount of $5,431,383, associated with this renewable generation have been detailed in Table 19 below. This amount includes costs on account of renewable generation projects in 2013 in the amount of $48,000. HCHI will be recording the provincial recovery portion of these 2013 costs to deferral account 1531, "Renewable Connection Capital Deferral Account" as described in Tab 2, Schedule 1 of this Exhibit, and included as part of the revenue requirement calculation for provincial recovery. The direct benefit portion of the 2013 and 2014 capital costs in the amount of $471,218 have been included in HCHI's regular capital using the half-year rule and forming part of the Fixed Asset Average Net Book Value for the 2014 Test Year.

Table 19
Renewable Generator Connection Capital Projects

HCHI Generator Connection Capital Projects 2013 – 2018							
Capital Cost for Renewables	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**Total**
REG Enabling Improvement Investments							
SCADA System		$246,000					$246,000
REG Expansion Investments							
Dunnville TS - New Feeder Egress & Metering			$260,000				$260,000
LDC Generator Cost Cap	$22,500	$900,000	$900,000	$900,000	$900,000	$900,000	$4,522,500
Dunnville TS Breaker Position	$25,500	$377,383					$402,883
Total REG Capital Investments	$48,000	$1,523,383	$1,160,000	$900,000	$900,000	$900,000	$5,431,383

Requested Deferral Account – REG Capital Investments

In conjunction with the preparation of this Application, HCHI is proposing to record REG capital investments for 2013 through to 2018 inclusive in the deferral account 1531 - "Renewable Connection Capital Deferral Account". The total amount to be recorded to deferral account 1531 of $4,960,165 is detailed in Table 20 below.

Table 20
REG Capital Investments – Account 1531

REG Enabling Improvement Investments	2013	2014	2015	2016	2017	2018	Total
Provincial Recovery Portion (94%)							
SCADA System		231,240					231,240
Total Provincial Recovery Portion	**-**	**231,240**					**231,240**
REG Expansion Investments	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**Total**
Direct Benefit Portion (17%)							
Cost Cap - 250 kW Renewable Generator							
Dunnville TS Breaker Position							
Cost Cap - Renewable Generator			153,000	153,000	153,000	153,000	612,000
Dunnville TS - Feeder Egress / Metering			44,200				44,200
Total Direct Benefit Portion	**-**	**-**	**197,200**	**153,000**	**153,000**	**153,000**	**656,200**
Provincial Recovery Portion (83%)							
Cost Cap - 250 kW Renewable Generator	18,675						18,675
Dunnville TS Breaker Position	21,165	313,325					334,490
Cost Cap - Renewable Generator		747,000	747,000	747,000	747,000	747,000	3,735,000
Dunnville TS - Feeder Egress / Metering			215,800				215,800
Total Provincial Recovery Portion	**39,840**	**1,060,325**	**962,800**	**747,000**	**747,000**	**747,000**	**4,303,965**
Total Account 1531 REG Capital Investments	**39,840**	**1,060,325**	**1,160,000**	**900,000**	**900,000**	**900,000**	**4,960,165**

The 2013 and 2014 REG capital investment portion of spending in the above table represents provincial recovery portions only. The direct benefit portion of 2013 and 2014 REG capital investment has been recorded directly to HCHI's regular capital as noted in Tab 5, Schedule 1. The forecast REG capital spending for the years 2015 to 2018 inclusive includes both the direct benefit and provincial recovery portions.

REG Funding Request – Provincial Recovery

In accordance with the Filing Requirements and section 79.1 of the OEB Act and Regulation 330/09 under the OEB Act, HCHI has included as part of this Application a request for recovery from all Ontario ratepayers (net of direct benefits) for its renewable generation connection investments for the years 2013 to 2018 inclusive. HCHI has assumed the provincial recovery percentages to be 83% for REG expansion investments and 94% for REG enabling improvement investments.

HCHI has completed OEB Append 2-FA "Proposed REG Investment" which identifies all eligible investments for which it is requesting cost recovery. These investments have been detailed in HCHI's REG Plan and in Table 19 above. The REG investments have been allocated between HCHI's ratepayers (i.e. direct benefit) and between all Ontario ratepayers (i.e. provincial recovery) detailed in Table 20 above.

In accordance with the Filing Requirements, HCHI has calculated the revenue requirement for the provincial recovery portion using the OEB Appendices 2-FB "Calculation of REG Improvement" and 2-FC "Calculation of REG Expansion", filed as Appendix D to this Exhibit and in Excel format as part of this Application. The revenue requirement for the eligible capital investments results in an annual recovery amount requested through Regulation 330/09 Provincial Rate Protection. Table 21 provides a summary of the annual / monthly amounts requested from the IESO in each year.

Table 21
Recovery Requested from Ontario Ratepayers (net of Direct Benefit)

Provincial Recovery (All Ontario Ratepayers)	2014 Test Year	2015 Forecast Year	2016 Forecast Year	2017 Forecast Year	2018 Forecast Year
REG Enabling Improvements (94%)					
Revenue Requirement	$ 18,404	$ 47,225	$ 61,123	$ 64,964	$ 64,279
REG Expansions (83%)					
Revenue Requirement	$ 65,204	$ 186,654	$ 285,537	$ 370,075	$ 453,083
Total Requested Provincial Rate Protection	$ 83,608	$ 233,879	$ 346,660	$ 435,039	$ 517,362
Monthly Amount Requested from IESO	$ 6,967	$ 19,490	$ 28,888	$ 36,253	$ 43,114

If approved for the provincial recovery portion on account of REG Investments, to be received from all Ontario ratepayers monthly through the IESO, HCHI will record the revenue received from the IESO in a separate sub-account of 1533 “Renewable Generation Connection Funding Adder Deferral Account” as described in Tab 2, Schedule 1 of this Exhibit.

REG Funding Request – LDC Specific Funding Adder – Direct Benefit

In accordance with the Filing Requirements and section 79.1 of the OEB Act and Regulation 330/09 under the OEB Act, HCHI has included as part of this Application a request for a funding adder specific to HCHI's ratepayers on account of the direct benefit portion of its renewable generation connection investments for the forecast years 2015 to 2018 inclusive. HCHI has assumed the direct benefit percentages to be 17% for REG expansion investments and 6% for REG enabling improvement investments.

As already noted in Tab 5, Schedule 3, HCHI has completed OEB Append 2-FA "Proposed REG Investment" which identifies all eligible investments for which it is requesting cost recovery. These investments have been detailed in HCHI's REG Plan and in Table 19 above. The REG investments have been allocated between HCHI's ratepayers (i.e. direct benefit) and between all Ontario ratepayers (i.e. provincial recovery) as detailed in Table 20 at Tab 5, Schedule 2 of this Exhibit.

In accordance with the Filing Requirements, HCHI has calculated the revenue requirement for the direct benefit portion relating to HCHI's ratepayers using the OEB Appendices 2-FB "Calculation of REG Improvement" and 2-FC "Calculation of REG Expansion", filed as Appendix D to this Exhibit and in Excel format as part of this Application. As mentioned in Tab 5, Schedules 1 and 2, the direct benefit portion of the 2013 and 2014 capital costs in the amount of $471,218 have been included in HCHI's regular capital using the half-year rule forming part of the Fixed Asset Average Net Book Value for the 2014 Test Year.

Table 22 below details the annual revenue requirement on account of the forecast eligible REG investments required from HCHI's own customers. Table 23 provides the Funding Adder calculation as requested as part of this Application based on the cumulative revenue requirement. The funding adder is based on collection over the 5 year rate term.

Table 22
REG Investment Revenue Requirement for HCHI's Ratepayers (2015 to 2018)

Direct Benefit (HCHI's Ratepayers)	2015 Forecast Year	2016 Forecast Year	2017 Forecast Year	2018 Forecast Year	Total
REG Enabling Improvements (6%)					
Revenue Requirement	$ 3,015	$ 3,901	$ 4,146	$ 4,103	$ 15,165
REG Expansions (17%)					
Revenue Requirement	$ 38,230	$ 58,483	$ 75,798	$ 92,800	$ 265,311
Total Revenue Requirement from 2015 to 2018	$ 41,245	$ 62,384	$ 79,944	$ 96,903	$ 280,476

Table 23
REG Investment Funding Adder (2015 to 2018)

RATE CLASS	Proposed Net Revenue Allocation	Proposed Revenue Allocation per Rate Class (Cost Allocation)	REG Improvement Investments Revenue Requirement	REG Expansionn Investments Revenue Requirement	REG Investment Total Revenue Requirement	BILLING UNITS (2014)		REG Funding Adder $ / unit
								(5 years)
Residential	$ 8,892,831	71.2%	$ 10,798	$ 188,901	$ 199,699	169,003,519	kWh	**$ 0.0002**
General Service Less Than 50 kW	1,711,607	13.7%	$ 2,078	$ 36,348	$ 38,426	53,925,141	kWh	**$ 0.0001**
General Service 50 to 4,999 kW	1,430,482	11.5%	$ 1,744	$ 30,511	$ 32,255	342,324	kW	**$ 0.0188**
Sentinel Lighting	118,345	0.9%	$ 136	$ 2,388	$ 2,524	909	kW	**$ 0.5553**
Street Lighting	321,966	2.6%	$ 394	$ 6,898	$ 7,292	6,648	kW	**$ 0.2194**
Unmetered Scattered Load	17,974	0.1%	$ 15	$ 265	$ 280	350,238	kWh	**$ 0.0002**
Total	**$ 12,493,205**	**100.0%**	**$ 15,165**	**$ 265,311**	**$ 280,476**			

If approved for the LDC specific Funding Adder on account of REG Investments associated with the direct benefit portion for the forecast period 2015 to 2018, HCHI will record the revenue received from its own customers in a separate sub-account of 1533 "Renewable Generation Connection Funding Adder Deferral Account" as described in Tab 2, Schedule 1 of this Exhibit.

LOST REVENUE ADJUSTMENT MECHANISM ("LRAM")

Overview

The Lost Revenue Adjustment Mechanism ("LRAM") was developed to remove the disincentive to electricity local distribution companies ("LDCs") from conservation and demand management ("CDM") programs. CDM programs are designed to provide energy and peak demand savings for LDC customers which directly impacts distribution revenue. The LRAM allows LDCs to be compensated for this lost revenue.

HCHI has contracted with the OPA to offer a variety of CDM programs for the 2011 to 2014 period. For this 2011 to 2014 period, the Board has authorized LDCs to establish an LRAM variance account ("LRAMVA") to capture the impact of CDM programs on the distributor's revenue. As per the Board's "*Guidelines for Electricity Distributor Conservation and Demand Management*" ("CDM Guidelines") (EB-2012-0003) issued April 26, 2012, the LRAMVA is to account for the lost revenue due to independently verified CDM results (load impacts) and the lost revenue from any CDM impacts HCHI may have included in its 2010 load forecast for these same programs. HCHI did not include any load reductions in its previously approved 2010 load forecast attributable to the OPA CDM 2011 to 2014 programs.

The CDM Guidelines, specifically Appendix A, indicate that LDCs with a cost of service application in 2010 were entitled to claim lost revenues from 2011 programs as part of their 2013 IRM3 rate applications, and lost revenues from 2012 programs and 2011 programs persistence into 2012 as part of their 2014 IRM3 rate applications.

HCHI did not submit a claim for lost revenues from the OPA CDM 2011 programs as part of its 2013 IRM3 rate application. HCHI has included with this Application lost revenue calculations for the following:

1. 2011 OPA CDM programs lost revenue in 2011;
2. 2011 OPA CDM programs lost revenue persistence into 2012; and

3. 2012 OPA CDM programs lost revenue in 2012.

The balance in HCHI's LRAMVA 1568 is based on the above three lost revenue calculations as included in the OEB's "2014 EDDVAR Continuity Schedule" (refer to Appendices A and B). Carrying charges have only been projected for the period January 1 2013 to April 30, 2014 as calculated directly in the OEB's 2014 EDDVAR model. HCHI did not include any carrying charges prior to January 1, 2013 as the amount was not recorded in HCHI's LRAMVA until 2013.

The lost revenue calculations have been based on the OPA's final verified CDM evaluation reports for both the 2011 programs and the 2012 programs. The 2011 program results are attached as Appendix E and the 2012 program results are attached as Appendix F to this Exhibit. HCHI has also included the OPA's final verified results for CDM programs for the period 2006 to 2010 as Appendix D.

IndEco Strategic Consulting Inc. ("IndEco") has prepared and assisted HCHI with its LRAM calculations. A report prepared by IndEco on the calculation of HCHI's LRAMVA for the period 2011 to 2012 has been included as Appendix G to this Exhibit.

HCHI does not have any Board approved CDM programs.

LRAM AMOUNT AND RATE RIDER CALCULATIONS

Determination of LRAM Amount

HCHI is requesting an LRAM amount of $82,208 related to CDM activities in 2011 and 2012 plus carrying charges of $1,611, for a total claimed amount of $83,818. This total amount has been recorded in HCHI's LRAMVA 1568 in 2013 and requested for disposition and recovery through a rate rider to specific customer rate classes over a one-year period commencing May 1, 2014.

The Filing Requirements state that distributors must apply for the disposition in the LRAMVA as part of their cost of service applications. Accordingly, HCHI has included this LRAMVA in the OEB's "2014 EDDVAR Continuity Schedule" as detailed in Tables 9 and 11 of Tab 2, Schedule 4 of this Exhibit.

HCHI's LRAM has been calculated using the OPA CDM final verified results for 2011 and 2012 as discussed in Tab 6, Schedule 1. These kWh savings by program by customer rate class are multiplied by the distribution volumetric rates effective at the time the kWh savings occurred. HCHI's rate year is effective from May 1 of the year to April 30 of the following year. The kWh savings are on a calendar year basis. Therefore, the distribution volumetric rates have been prorated to match the kWh savings (i.e. 4 months of prior rate year – January to April, and 8 months of current rate year – May to December). Table 24 below illustrates the rates used in the LRAM calculations.

Table 24
Distribution Volumetric Rates used for LRAM Calculations

		Prorated Rates to be Used				Rates per Board Approved Rate Orders			
Customer Class	**Billing Unit**	**2011**	**2012**	**2013**	**2014**	**Effective May 1, 2010**	**Effective May 1, 2011**	**Effective May 1, 2012**	**Effective May 1, 2013**
Residential	kWh	0.0319	0.0294	0.0270	0.0262	0.0334	0.0311	0.0285	0.0262
General Service Less Than 50 kW	kWh	0.0202	0.0201	0.0202	0.0203	0.0202	0.0202	0.0201	0.0203
General Service 50 to 4,999 kW	kW	4.9462	4.7639	4.7890	4.8015	5.3113	4.7636	4.7641	4.8015

Notes: Only the Distribution Volumetric Rate and the Rate Rider for Application of Tax Change have been used. (Based on verbal instructions from Josh Wasylyk, Advisor, Conservation & Reporting at the Ontario Energy Board (2013-07-12))
May 1, 2010 rates - Rate Order EB-2009-0265 issued April 26, 2010
May 1, 2011 rates - Rate Order EB-2010-0086 revised April 6, 2011
May 1, 2012 rates - Decision and Order EB-2011-0170 issued April 4, 2012
May 1, 2013 and beyond rates - Rate Order EB-2012-0129 revised April 11, 2013 and corrected April 16, 2013

Lost Revenue Calculation

Tables 25 and 26 provide the 2011 and 2012 lost revenue, respectively, as calculated by IndEco on HCHI's behalf.

Table 25
2011 Lost Revenue Calculation

Initiative	**Residential**	**General Service Less Than 50 kW**	**General Service 50 to 4,999 kW**	**Total**
	kWh	**kWh**	**kW**	
Consumer Program				
Appliance Retirement	115,815	-	-	
Appliance Exchange	2,618	-	-	
HVAC Incentives	161,809	-	-	
Conservation Instant Coupon Booklet	82,467	-	-	
Bi-Annual Retailer Event	133,989	-	-	
Business Program				
Efficiency: Equipment Replacement	-	233,725	458	
Direct Install Lighting	-	156,830	-	
New Construction and Major Renovation Incentive	-	-	133	
Industrial Program				
Demand Response 3 - see Note 1	-	-	253	
Pre-2011 Programs completed in 2011				
Electricity Retrofit Incentive Program	-	14,778	20	
High Performance New Construction	-	-	856	
Total kWh / kW Savings	**496,699**	**405,333**	**1,467**	
Prorated Volumetric Rate to be Used	0.0319	0.0202	4.9462	
Total Lost Revenue in 2011	**$15,828**	**$8,188**	**$7,255**	**$31,271**
2011 savings persisting in 2012	**496,699**	**405,333**	**1,467**	
2011 savings persisting in 2013	**496,699**	**405,333**	**1,467**	
2011 savings persisting in 2014	**495,381**	**364,875**	**1,467**	

Note 1: Demand Response 3 Program does not contribute to Lost Revenue

Table 26
2012 Lost Revenue Calculation

Initiative	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Total
	kWh	kWh	kW	
Consumer Program				
Appliance Replacement	61,427	-	-	
Appliance Exchange	9,228	-	-	
HVAC Incentives	98,468	-	-	
Conservation Instant Coupon Booklet	5,934	-	-	
Bi-Annual Retailer Event	113,664	-	-	
Residential Demand Response (switch/pstat	55	-	-	
Residential New Construction	415	-	-	
Business Program				
Retrofit	-	251,546	654	
Direct Install Lighting	-	149,154	-	
New Construction	-	-	132	
Industrial Program				
Demand Response 3	-	-	1,548	
Home Assistance Program				
Home Assistance Program	30,560	-	-	
Total kWh / kW Savings	**319,751**	**400,700**	**786**	
Prorated Volumetric Rate to be Used	0.0294	0.0201	4.7639	
Lost Revenue in 2012 from 2012	**$9,390**	**$8,067**	**$3,744**	**$21,201**
2011 savings persisting in 2012	**496,699**	**405,333**	**1,467**	
Lost Revenue in 2012 from 2011	**$14,587**	**$8,161**	**$6,988**	**$29,736**
Total Lost Revenue in 2012	**$23,977**	**$16,228**	**$10,732**	**$50,937**
2012 savings persisting in 2013	**319,696**	**400,700**	**786**	
2012 savings persisting in 2014	**319,696**	**400,700**	**784**	

Note 1: Demand Response 3 Program does not contribute to Lost Revenue

Carrying Charges Calculation

Carrying charges have been calculated using the Board's prescribed interest rate published for each quarter as detailed in Table 8 of Tab 2, Schedule 2 of this Exhibit. As stated in the "Overview" section of this Tab, carrying charges have only been calculated and recorded on HCHI's books for the period January 1, 2013 to April 30, 2014. HCHI did not record its LRAMVA until 2013 and has commenced calculating the carrying charges at the same time. The following Table 27 provides the detailed calculations of the carrying charges by customer rate class.

Table 27
LRAMVA Carrying Charges by Customer Class

Month	Period	Prescribed Interest Rate	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Total
Jan-13	2013 Q1	1.47%	$ 48.76	$ 29.91	$ 22.04	$ 100.71
Feb-13	2013 Q1	1.47%	48.76	29.91	22.04	100.71
Mar-13	2013 Q1	1.47%	48.76	29.91	22.04	100.71
Apr-13	2013 Q2	1.47%	48.76	29.91	22.04	100.71
May-13	2013 Q2	1.47%	48.76	29.91	22.04	100.71
Jun-13	2013 Q2	1.47%	48.76	29.91	22.04	100.71
Jul-13	2013 Q3	1.47%	48.76	29.91	22.04	100.71
Aug-13	2013 Q3	1.47%	48.76	29.91	22.04	100.71
Sep-13	2013 Q3	1.47%	48.76	29.91	22.04	100.71
Oct-13	2013 Q4	1.47%	48.76	29.91	22.04	100.71
Nov-13	2013 Q4	1.47%	48.76	29.91	22.04	100.71
Dec-13	2013 Q4	1.47%	48.76	29.91	22.04	100.71
Jan-14	2014 Q1	1.47%	48.76	29.91	22.04	100.71
Feb-14	2014 Q1	1.47%	48.76	29.91	22.04	100.71
Mar-14	2014 Q1	1.47%	48.76	29.91	22.04	100.71
Apr-14	2014 Q2	1.47%	48.76	29.91	22.04	100.71
Total Carrying Charges Claimed			**$ 780.16**	**$ 478.56**	**$ 352.64**	**$ 1,611.36**

Rate Rider Calculations

As noted in Tab 2, Schedule 3 of this Exhibit and in Table 9 of this same Tab, the LRAMVA has been included in the OEB's "2014 EDDVAR Continuity Schedule" along with the Group 1 DVAs and the Group 2 DVAs to calculate one combined rate rider to the customer; that is, with the exception of the Global Adjustment Group 1 account 1589. The rate riders by customer rate class can be found in Table 12 of Tab 2, Schedule 4.



	Account Descriptions	Account Number	2005									2006									
			Opening Principal Amounts as of Jan-1-05	Transactions Debit / (Credit) during 2005 excluding interest and adjustments [3]	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	Opening Principal Amounts as of Jan-1-06	Transactions Debit / (Credit) during 2006 excluding interest and adjustments [3]	Board-Approved Disposition during 2006 [1, 1A]	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, 1A]	Adjustments during 2006 - other [2]	Closing Interest Amounts as of Dec-31-06
	Group 1 Accounts																					
1	LV Variance Account	1550					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
2	RSVA - Wholesale Market Service Charge	1580					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
3	RSVA - Retail Transmission Network Charge	1584					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
4	RSVA - Retail Transmission Connection Charge	1586					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
5	RSVA - Power (excluding Global Adjustment)	1588					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
6	RSVA - Global Adjustment	1589					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
7	Recovery of Regulatory Asset Balances	1590					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
8	Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
9	Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
9	Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
10	Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
	Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	RSVA - Global Adjustment	**1589**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Group 2 Accounts																					
11	Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
12	Other Regulatory Assets - Sub-Account - Pension Contributions	1508					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
13	Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
14	Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508																				
15	Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508																				
16	Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508																				
17	Other Regulatory Assets - Sub-Account - Other [4]	1508					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
18	Retail Cost Variance Account - Retail	1518					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
19	Misc. Deferred Debits	1525					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
20	Renewable Generation Connection Capital Deferral Account	1531																				
21	Renewable Generation Connection OM&A Deferral Account	1532																				
22	Renewable Generation Connection Funding Adder Deferral Account	1533																				
23	Smart Grid Capital Deferral Account	1534																				
24	Smart Grid OM&A Deferral Account	1535																				
25	Smart Grid Funding Adder Deferral Account	1536																				
26	Retail Cost Variance Account - STR	1548					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
27	Board-Approved CDM Variance Account	1567																				
28	Extra-Ordinary Event Costs	1572					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
29	Deferred Rate Impact Amounts	1574					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
30	RSVA - One-time	1582					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
31	Other Deferred Credits	2425					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
	Group 2 Sub-Total		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
32	Deferred Payments in Lieu of Taxes	1562					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
33	PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
34	PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
	Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
35	**LRAM Variance Account**	**1568**																				
	Total including Account 1568		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
36	Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[10]	1555					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
37	Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[10]	1555					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
38	Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[10]	1555					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
39	Smart Meter OM&A Variance[10]	1556					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
40	IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[9]	1575																				
41	Accounting Changes Under CGAAP Balance + Return Component[9]	1576																				
	The following is not included in the total claim but are included on a memo basis:																					
42	Deferred PILs Contra Account [5]	1563					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
43	PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00
44	Disposition and Recovery of Regulatory Balances[7]	1595					$0.00					$0.00	$0.00				$0.00	$0.00				$0.00



Account Descriptions	Account Number	2007										2008									
		Opening Principal Amounts as of Jan-1-07	Transactions Debit / (Credit) during 2007 excluding interest and adjustments [3]	Board-Approved Disposition during 2007	Adjustments during 2007 - other [2]	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 [2]	Closing Interest Amounts as of Dec-31-07	Opening Principal Amounts as of Jan-1-08	Transactions Debit / (Credit) during 2008 excluding interest and adjustments [3]	Board-Approved Disposition during 2008	Adjustments during 2008 - other [2]	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 [2]	Closing Interest Amounts as of Dec-31-08
Group 1 Accounts																					
LV Variance Account	1550	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
RSVA - Wholesale Market Service Charge	1580	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
RSVA - Retail Transmission Network Charge	1584	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
RSVA - Retail Transmission Connection Charge	1586	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
RSVA - Power (excluding Global Adjustment)	1588	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
RSVA - Global Adjustment	1589	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Recovery of Regulatory Asset Balances	1590	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RSVA - Global Adjustment	**1589**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Group 2 Accounts																					
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508																				
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508																				
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508																				
Other Regulatory Assets - Sub-Account - Other [4]	1508	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Retail Cost Variance Account - Retail	1518	$0.00				$0.00	$0.00				$0.00	$0.00			$313,278.71	$313,278.71	$0.00			$34,474.23	$34,474.23
Misc. Deferred Debits	1525	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Renewable Generation Connection Capital Deferral Account	1531																				
Renewable Generation Connection OM&A Deferral Account	1532																				
Renewable Generation Connection Funding Adder Deferral Account	1533																				
Smart Grid Capital Deferral Account	1534																				
Smart Grid OM&A Deferral Account	1535																				
Smart Grid Funding Adder Deferral Account	1536																				
Retail Cost Variance Account - STR	1548	$0.00				$0.00	$0.00				$0.00	$0.00			$3,780.54	$3,780.54	$0.00			$1,014.52	$1,014.52
Board-Approved CDM Variance Account	1567																				
Extra-Ordinary Event Costs	1572	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Deferred Rate Impact Amounts	1574	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
RSVA - One-time	1582	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Other Deferred Credits	2425	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Group 2 Sub-Total		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$317,059.25	$317,059.25	$0.00	$0.00	$0.00	$35,488.75	$35,488.75
Deferred Payments in Lieu of Taxes	1562	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$317,059.25	$317,059.25	$0.00	$0.00	$0.00	$35,488.75	$35,488.75
LRAM Variance Account	**1568**																				
Total including Account 1568		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$317,059.25	$317,059.25	$0.00	$0.00	$0.00	$35,488.75	$35,488.75
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[10]	1555	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[10]	1555	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[10]	1555	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Smart Meter OM&A Variance[10]	1556	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[9]	1575																				
Accounting Changes Under CGAAP Balance + Return Component[9]	1576																				
The following is not included in the total claim but are included on a memo basis:																					
Deferred PILs Contra Account [5]	1563	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Disposition and Recovery of Regulatory Balances[7]	1595	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00



Account Descriptions	Account Number	2009										2010									
		Opening Principal Amounts as of Jan-1-09	Transactions Debit / (Credit) during 2009 excluding interest and adjustments [3]	Board-Approved Disposition during 2009	Adjustments during 2009 - other [2]	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 [2]	Closing Interest Amounts as of Dec-31-09	Opening Principal Amounts as of Jan-1-10	Transactions Debit / (Credit) during 2010 excluding interest and adjustments [3]	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	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	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
RSVA - Wholesale Market Service Charge	1580	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
RSVA - Retail Transmission Network Charge	1584	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
RSVA - Retail Transmission Connection Charge	1586	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
RSVA - Power (excluding Global Adjustment)	1588	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
RSVA - Global Adjustment	1589	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Recovery of Regulatory Asset Balances	1590	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Disposition and Recovery/Refund of Regulatory Balances (2008) [7]	1595	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Disposition and Recovery/Refund of Regulatory Balances (2009) [7]	1595	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Disposition and Recovery/Refund of Regulatory Balances (2010) [7]	1595	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Disposition and Recovery/Refund of Regulatory Balances (2011) [7]	1595	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RSVA - Global Adjustment	**1589**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Group 2 Accounts																					
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0.00	$5,231.74			$5,231.74	$0.00	$7.86			$7.86	$5,231.74	$707.24			$5,938.98	$7.86	$46.80			$54.66
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act [8]	1508																				
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508																				
Other Regulatory Assets - Sub-Account - Other [4]	1508	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Retail Cost Variance Account - Retail	1518	$313,278.71	$80,543.43			$393,822.14	$34,474.23	$3,822.19			$38,296.42	$393,822.14	$77,554.98	$313,278.71		$158,098.41	$38,296.42	$1,556.29	$38,612.00		$1,240.71
Misc. Deferred Debits	1525	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Renewable Generation Connection Capital Deferral Account	1531					$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Renewable Generation Connection OM&A Deferral Account	1532					$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Renewable Generation Connection Funding Adder Deferral Account	1533					$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Smart Grid Capital Deferral Account	1534					$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Smart Grid OM&A Deferral Account	1535					$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Smart Grid Funding Adder Deferral Account	1536					$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Retail Cost Variance Account - STR	1548	$3,780.54	$1,729.40			$5,509.94	$1,014.52	$49.07			$1,063.59	$5,509.94	$1,185.90	$3,780.54		$2,915.30	$1,063.59	$25.21	$1,065.00		$23.80
Board-Approved CDM Variance Account	1567										$0.00					$0.00	$0.00				$0.00
Extra-Ordinary Event Costs	1572	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Deferred Rate Impact Amounts	1574	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
RSVA - One-time	1582	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Other Deferred Credits	2425	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Group 2 Sub-Total		$317,059.25	$87,504.57	$0.00	$0.00	$404,563.82	$35,488.75	$3,879.12	$0.00	$0.00	$39,367.87	$404,563.82	$79,448.12	$317,059.25	$0.00	$166,952.69	$39,367.87	$1,628.30	$39,677.00	$0.00	$1,319.17
Deferred Payments in Lieu of Taxes	1562	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0.00				$0.00	$0.00				$0.00	$0.00	-$11,153.85			-$11,153.85	$0.00				$0.00
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$317,059.25	$87,504.57	$0.00	$0.00	$404,563.82	$35,488.75	$3,879.12	$0.00	$0.00	$39,367.87	$404,563.82	$68,294.28	$317,059.25	$0.00	$155,798.85	$39,367.87	$1,628.30	$39,677.00	$0.00	$1,319.17
LRAM Variance Account	**1568**															$0.00					$0.00
Total including Account 1568		$317,059.25	$87,504.57	$0.00	$0.00	$404,563.82	$35,488.75	$3,879.12	$0.00	$0.00	$39,367.87	$404,563.82	$68,294.28	$317,059.25	$0.00	$155,798.85	$39,367.87	$1,628.30	$39,677.00	$0.00	$1,319.17
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital [10]	1555	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries [10]	1555	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs [10]	1555	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
Smart Meter OM&A Variance [10]	1556	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component [9]	1575																				
Accounting Changes Under CGAAP Balance + Return Component [9]	1576																				
The following is not included in the total claim but are included on a memo basis:																					
Deferred PILs Contra Account [5]	1563	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$0.00				$0.00	$0.00				$0.00	$0.00	$22,307.69			$22,307.69	$0.00				$0.00
Disposition and Recovery of Regulatory Balances [7]	1595	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00	$0.00				$0.00



Account Descriptions	Account Number	2011									2012											
		Opening Principal Amounts as of Jan-1-11	Transactions Debit / (Credit) during 2011 excluding interest and adjustments [3]	Board-Approved Disposition during 2011	Adjustments during 2010 - other [2]	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 [2]	Closing Interest Amounts as of Dec-31-11	Opening Principal Amounts as of Jan-1-12	Transactions Debit / (Credit) during 2012 excluding interest and adjustments [3]	Board-Approved Disposition during 2012	Other [2] Adjustments during Q1 2012	Other [2] Adjustments during Q2 2012	Other [2] Adjustments during Q3 2012	Other [2] Adjustments during Q4 2012	Closing Principal Balance as of Dec-31-12	Opening Interest Amounts as of Jan-1-12	Interest Jan-1 to Dec-31-12	Board-Approved Disposition during 2012	Adjustments during 2012 - other [2]	Closing Interest Amounts as of Dec-31-12
Group 1 Accounts																							
LV Variance Account	1550	$0.00			-$111,053.87	-$111,053.87	$0.00			-$2,371.97	-$2,371.97	-$111,053.87	-$20,778.56	-$79,821.23					-$52,011.20	-$2,371.97	-$891.69	-$2,530.49		-$733.17
RSVA - Wholesale Market Service Charge	1580	$0.00			-$1,058,927.69	-$1,058,927.69	$0.00			-$14,311.36	-$14,311.36	-$1,058,927.69	-$621,198.65	-$516,957.93					-$1,163,168.41	-$14,311.36	-$14,788.57	-$13,158.39		-$15,941.54
RSVA - Retail Transmission Network Charge	1584	$0.00			-$49,952.35	-$49,952.35	$0.00			$1,026.34	$1,026.34	-$49,952.35	-$110,935.12	-$1,813.70					-$159,073.77	$1,026.34	-$1,298.39	$603.09		-$875.14
RSVA - Retail Transmission Connection Charge	1586	$0.00			-$227,529.12	-$227,529.12	$0.00			-$2,116.63	-$2,116.63	-$227,529.12	-$92,846.54	-$214,029.40					-$106,346.26	-$2,116.63	-$1,675.72	-$4,001.04		$208.69
RSVA - Power (excluding Global Adjustment)	1588	$0.00			-$17,895.18	-$17,895.18	$0.00			-$1,299.28	-$1,299.28	-$17,895.18	-$61,236.20	$62,160.91					-$141,292.29	-$1,299.28	-$811.42	$341.37		-$2,452.07
RSVA - Global Adjustment	1589	$0.00			-$539,078.19	-$539,078.19	$0.00			-$9,493.98	-$9,493.98	-$539,078.19	$611,072.09	-$390,706.61					$462,700.51	-$9,493.98	-$4,371.88	-$11,829.95		-$2,035.91
Recovery of Regulatory Asset Balances	1590	$0.00				$0.00	$0.00				$0.00	$0.00							$0.00	$0.00				$0.00
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$0.00				$0.00	$0.00				$0.00	$0.00							$0.00	$0.00				$0.00
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$0.00				$0.00	$0.00				$0.00	$0.00							$0.00	$0.00				$0.00
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$0.00			-$204,091.80	-$204,091.80	$0.00			$118,888.28	$118,888.28	-$204,091.80	$176.74					-$176.74	-$204,091.80	$118,888.28	-$2,999.27		-$1,000.93	$114,888.08
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595	$0.00	-$381,854.43			-$381,854.43	$0.00	-$18,853.78			-$18,853.78	-$381,854.43	$381,131.24					-$31.37	-$754.56	-$18,853.78	-$1,386.49			-$20,240.27
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0.00	-$381,854.43	$0.00	-$2,208,528.20	-$2,590,382.63	$0.00	-$18,853.78	$0.00	$90,321.40	$71,467.62	-$2,590,382.63	$85,385.00	-$1,141,167.96	$0.00	$0.00	$0.00	-$208.11	-$1,364,037.78	$71,467.62	-$28,223.43	-$30,575.41	-$1,000.93	$72,818.67
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0.00	-$381,854.43	$0.00	-$1,669,450.01	-$2,051,304.44	$0.00	-$18,853.78	$0.00	$99,815.38	$80,961.60	-$2,051,304.44	-$525,687.09	-$750,461.35	$0.00	$0.00	$0.00	-$208.11	-$1,826,738.29	$80,961.60	-$23,851.55	-$18,745.46	-$1,000.93	$74,854.58
RSVA - Global Adjustment	**1589**	$0.00	$0.00	$0.00	-$539,078.19	-$539,078.19	$0.00	$0.00	$0.00	-$9,493.98	-$9,493.98	-$539,078.19	$611,072.09	-$390,706.61	$0.00	$0.00	$0.00	$0.00	$462,700.51	-$9,493.98	-$4,371.88	-$11,829.95	$0.00	-$2,035.91
Group 2 Accounts																								
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$0.00				$0.00	$0.00				$0.00	$0.00							$0.00	$0.00				$0.00
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$0.00				$0.00	$0.00				$0.00	$0.00							$0.00	$0.00				$0.00
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0.00				$0.00	$0.00				$0.00	$0.00							$0.00	$0.00				$0.00
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$5,938.98				$5,938.98	$54.66	$87.36			$142.02	$5,938.98							$5,938.98	$142.02	$87.36			$229.38
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[9]	1508	$0.00				$0.00	$0.00				$0.00	$0.00							$0.00	$0.00				$0.00
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	$0.00				$0.00	$0.00				$0.00	$0.00							$0.00	$0.00				$0.00
Other Regulatory Assets - Sub-Account - Other [4]	1508	$0.00				$0.00	$0.00				$0.00	$0.00							$0.00	$0.00				$0.00
Retail Cost Variance Account - Retail	1518	$158,098.41	$78,678.55			$236,776.96	$1,240.71	$2,861.07			$4,101.78	$236,776.96	$80,240.87						$317,017.83	$4,101.78	$4,031.67			$8,133.45
Misc. Deferred Debits	1525	$0.00				$0.00	$0.00				$0.00	$0.00							$0.00	$0.00				$0.00
Renewable Generation Connection Capital Deferral Account	1531	$0.00				$0.00	$0.00				$0.00	$0.00							$0.00	$0.00				$0.00
Renewable Generation Connection OM&A Deferral Account	1532	$0.00				$0.00	$0.00				$0.00	$0.00							$0.00	$0.00				$0.00
Renewable Generation Connection Funding Adder Deferral Account	1533	$0.00				$0.00	$0.00				$0.00	$0.00							$0.00	$0.00				$0.00
Smart Grid Capital Deferral Account	1534	$0.00				$0.00	$0.00				$0.00	$0.00							$0.00	$0.00				$0.00
Smart Grid OM&A Deferral Account	1535	$0.00				$0.00	$0.00				$0.00	$0.00							$0.00	$0.00				$0.00
Smart Grid Funding Adder Deferral Account	1536	$0.00				$0.00	$0.00				$0.00	$0.00							$0.00	$0.00				$0.00
Retail Cost Variance Account - STR	1548	$2,915.30	$1,368.16			$4,283.46	$23.80	$53.12			$76.92	$4,283.46	$1,683.49						$5,966.95	$76.92	$74.19			$151.11
Board-Approved CDM Variance Account	1567	$0.00				$0.00	$0.00				$0.00	$0.00							$0.00	$0.00				$0.00
Extra-Ordinary Event Costs	1572	$0.00				$0.00	$0.00				$0.00	$0.00							$0.00	$0.00				$0.00
Deferred Rate Impact Amounts	1574	$0.00				$0.00	$0.00				$0.00	$0.00							$0.00	$0.00				$0.00
RSVA - One-time	1582	$0.00				$0.00	$0.00				$0.00	$0.00							$0.00	$0.00				$0.00
Other Deferred Credits	2425	$0.00				$0.00	$0.00				$0.00	$0.00							$0.00	$0.00				$0.00
Group 2 Sub-Total		$166,952.69	$80,046.71	$0.00	$0.00	$246,999.40	$1,319.17	$3,001.55	$0.00	$0.00	$4,320.72	$246,999.40	$81,924.36	$0.00	$0.00	$0.00	$0.00	$0.00	$328,923.76	$4,320.72	$4,193.22	$0.00	$0.00	$8,513.94
Deferred Payments in Lieu of Taxes	1562	$0.00				$0.00	$0.00				$0.00	$0.00							$0.00	$0.00				$0.00
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0.00				$0.00	$0.00				$0.00	$0.00							$0.00	$0.00				$0.00
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$11,153.85	-$23,583.32			-$34,737.16	$0.00			$0.00	$0.00	-$34,737.16	-$19,873.11					-$96,395.88	-$151,006.15	$0.00			-$1,534.82	-$1,534.82
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$155,798.85	-$325,391.04	$0.00	-$2,208,528.20	-$2,378,120.39	$1,319.17	-$15,852.23	$0.00	$90,321.40	$75,788.34	-$2,378,120.39	$147,436.26	-$1,141,167.96	$0.00	$0.00	$0.00	-$96,603.99	-$1,186,120.17	$75,788.34	-$24,030.21	-$30,575.41	-$2,535.75	$79,797.79
LRAM Variance Account	**1568**	$0.00				$0.00	$0.00				$0.00	$0.00						$82,207.00	$82,207.00	$0.00				$0.00
Total including Account 1568		$155,798.85	-$325,391.04	$0.00	-$2,208,528.20	-$2,378,120.39	$1,319.17	-$15,852.23	$0.00	$90,321.40	$75,788.34	-$2,378,120.39	$147,436.26	-$1,141,167.96	$0.00	$0.00	$0.00	-$14,396.99	-$1,103,913.17	$75,788.34	-$24,030.21	-$30,575.41	-$2,535.75	$79,797.79
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[10]	1555	$0.00				$0.00	$0.00				$0.00	$0.00							$0.00	$0.00				$0.00
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[10]	1555	$0.00				$0.00	$0.00				$0.00	$0.00							$0.00	$0.00				$0.00
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[10]	1555	$0.00				$0.00	$0.00				$0.00	$0.00							$0.00	$0.00				$0.00
Smart Meter OM&A Variance[10]	1556	$0.00				$0.00	$0.00				$0.00	$0.00							$0.00	$0.00				$0.00
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[9]	1575																		$0.00	$0.00				$0.00
Accounting Changes Under CGAAP Balance + Return Component[9]	1576																	-$1,878,699.00	-$1,878,699.00	$0.00				$0.00
The following is not included in the total claim but are included on a memo basis:																								
Deferred PILs Contra Account [5]	1563	$0.00				$0.00	$0.00				$0.00	$0.00							$0.00	$0.00				$0.00
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$22,307.69	$47,166.63			$69,474.32	$0.00			$0.00	$0.00	$69,474.32	$39,746.21					$192,791.76	$302,012.29	$0.00			$3,069.64	$3,069.64
Disposition and Recovery of Regulatory Balances[7]	1595	$0.00				$0.00	$0.00				$0.00	$0.00	-$900,504.87						-$900,504.87	$0.00	-$146,792.22			-$146,792.22



Account Descriptions	Account Number	2013 Principal Disposition during 2013 - instructed by Board	2013 Interest Disposition during 2013 - instructed by Board	2013 Closing Principal Balances as of Dec 31-12 Adjusted for Dispositions during 2013	2013 Closing Interest Balances as of Dec 31-12 Adjusted for Dispositions during 2013	Projected Interest on Dec-31-12 Balances: Projected Interest from Jan 1, 2013 to December 31, 2013 on Dec 31 -12 balance adjusted for disposition during 2013 [6]	Projected Interest on Dec-31-12 Balances: Projected Interest from January 1, 2014 to April 30, 2014 on Dec 31 -12 balance adjusted for disposition during 2013 [6]	Total Claim	2.1.7 RRR As of Dec 31-12	Variance RRR vs. 2012 Balance *(Principal + Interest)*
Group 1 Accounts										
LV Variance Account	1550	-$31,232.64	-$453.64	-$20,778.56	-$279.53	-$305.44	-$101.81	-$21,465.34	-$52,744.37	$0.00
RSVA - Wholesale Market Service Charge	1580	-$541,969.75	-$11,775.57	-$621,198.66	-$4,165.97	-$9,131.62	-$3,043.87	-$637,540.12	-$1,179,109.95	$0.00
RSVA - Retail Transmission Network Charge	1584	-$48,048.65	-$518.51	-$111,025.12	-$356.63	-$1,632.07	-$544.02	-$113,557.84	-$159,948.91	$0.00
RSVA - Retail Transmission Connection Charge	1586	-$13,429.79	$1,621.18	-$92,916.47	-$1,412.49	-$1,365.87	-$455.29	-$96,150.12	-$106,137.57	$0.00
RSVA - Power (excluding Global Adjustment)	1588	-$80,056.07	-$3,209.74	-$61,236.22	$757.67	-$900.17	-$300.06	-$61,678.78	-$143,744.36	$0.00
RSVA - Global Adjustment	1589	-$148,371.88	-$572.11	$611,072.39	-$1,463.80	$8,982.76	$2,994.25	$621,585.60	$460,664.60	$0.00
Recovery of Regulatory Asset Balances	1590			$0.00	$0.00			$0.00		$0.00
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595			$0.00	$0.00			$0.00		$0.00
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595			$0.00	$0.00			$0.00		$0.00
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	-$204,091.80	$114,888.08	$0.00	$0.00	$0.00	$0.00	$0.00	-$88,026.05	$1,177.67
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595			-$754.56	-$20,240.27	-$11.09	-$3.70	-$21,009.62	-$20,963.46	$31.37
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$1,067,200.58	$99,979.69	-$296,837.20	-$27,161.02	-$4,363.50	-$1,454.50	-$329,816.22	-$1,290,010.07	$1,209.04
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$918,828.70	$100,551.80	-$907,909.59	-$25,697.22	-$13,346.26	-$4,448.75	-$951,401.82	-$1,750,674.67	$1,209.04
RSVA - Global Adjustment	**1589**	-$148,371.88	-$572.11	$611,072.39	-$1,463.80	$8,982.76	$2,994.25	$621,585.60	$460,664.60	$0.00
Group 2 Accounts										
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508			$0.00	$0.00			$0.00		$0.00
Other Regulatory Assets - Sub-Account - Pension Contributions	1508			$0.00	$0.00			$0.00		$0.00
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508			$0.00	$0.00			$0.00		$0.00
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508			$5,938.98	$229.38	$87.30	$29.10	$6,284.76	$6,168.36	$0.00
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[9]	1508			$0.00	$0.00			$0.00		$0.00
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508			$0.00	$0.00			$0.00		$0.00
Other Regulatory Assets - Sub-Account - Other [4]	1508			$0.00	$0.00			$0.00		$0.00
Retail Cost Variance Account - Retail	1518			$317,017.83	$8,133.45	$4,660.16	$1,553.39	$331,364.83	$325,151.28	$0.00
Misc. Deferred Debits	1525			$0.00	$0.00			$0.00		$0.00
Renewable Generation Connection Capital Deferral Account	1531			$0.00	$0.00			$0.00		$0.00
Renewable Generation Connection OM&A Deferral Account	1532			$0.00	$0.00			$0.00		$0.00
Renewable Generation Connection Funding Adder Deferral Account	1533			$0.00	$0.00			$0.00		$0.00
Smart Grid Capital Deferral Account	1534			$0.00	$0.00			$0.00		$0.00
Smart Grid OM&A Deferral Account	1535			$0.00	$0.00			$0.00		$0.00
Smart Grid Funding Adder Deferral Account	1536			$0.00	$0.00			$0.00		$0.00
Retail Cost Variance Account - STR	1548			$5,966.95	$151.11	$87.71	$29.24	$6,235.01	$6,118.06	$0.00
Board-Approved CDM Variance Account	1567			$0.00	$0.00			$0.00		$0.00
Extra-Ordinary Event Costs	1572			$0.00	$0.00			$0.00		$0.00
Deferred Rate Impact Amounts	1574			$0.00	$0.00			$0.00		$0.00
RSVA - One-time	1582			$0.00	$0.00			$0.00		$0.00
Other Deferred Credits	2425			$0.00	$0.00			$0.00		$0.00
Group 2 Sub-Total		$0.00	$0.00	$328,923.76	$8,513.94	$4,835.17	$1,611.73	$343,884.60	$337,437.70	$0.00
Deferred Payments in Lieu of Taxes	1562			$0.00	$0.00			$0.00		$0.00
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592			$0.00	$0.00			$0.00		$0.00
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592			-$151,006.15	-$1,534.82	-$1,646.12	-$692.57	-$154,879.66	$0.00	$152,540.97
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		-$1,067,200.58	$99,979.69	-$118,919.59	-$20,181.90	-$1,174.45	-$535.34	-$140,811.28	-$952,572.37	$153,750.01
LRAM Variance Account	**1568**			$82,207.00	$0.00	$1,208.44	$402.81	$83,818.25	$0.00	-$82,207.00
Total including Account 1568		-$1,067,200.58	$99,979.69	-$36,712.59	-$20,181.90	$33.99	-$132.53	-$56,993.03	-$952,572.37	$71,543.00
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[10]	1555			$0.00	$0.00			$0.00		$0.00
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[10]	1555			$0.00	$0.00			$0.00		$0.00
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[10]	1555			$0.00	$0.00			$0.00		$0.00
Smart Meter OM&A Variance[10]	1556			$0.00	$0.00			$0.00		$0.00
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[9]	1575			$0.00	$0.00			$0.00		$0.00
Accounting Changes Under CGAAP Balance + Return Component[9]	1576			-$1,878,699.00	$0.00			-$1,878,699.00	$0.00	$1,878,699.00
The following is not included in the total claim but are included on a memo basis:										
Deferred PILs Contra Account [5]	1563			$0.00	$0.00			$0.00		$0.00
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592			$302,012.29	$3,069.64	$3,292.24	$1,385.14	$309,759.31	$0.00	-$305,081.93
Disposition and Recovery of Regulatory Balances[7]	1595			-$900,504.87	-$146,792.22			-$1,047,297.09	-$1,047,297.09	$0.00



	Account Descriptions	Account Number	2005									2006									
			Opening Principal Amounts as of Jan-1-05	Transactions Debit / (Credit) during 2005 excluding interest and adjustments [3]	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	Opening Principal Amounts as of Jan-1-06	Transactions Debit / (Credit) during 2006 excluding interest and adjustments [3]	Board-Approved Disposition during 2006 [1,1A]	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 [1,1A]	Adjustments during 2006 - other [2]	Closing Interest Amounts as of Dec-31-06
	Group 1 Accounts																					
1	LV Variance Account	1550					$0					$0	$0				$0	$0				$0
2	RSVA - Wholesale Market Service Charge	1580					$0					$0	$0				$0	$0				$0
3	RSVA - Retail Transmission Network Charge	1584					$0					$0	$0				$0	$0				$0
4	RSVA - Retail Transmission Connection Charge	1586					$0					$0	$0				$0	$0				$0
5	RSVA - Power (excluding Global Adjustment)	1588					$0					$0	$0				$0	$0				$0
6	RSVA - Global Adjustment	1589					$0					$0	$0				$0	$0				$0
7	Recovery of Regulatory Asset Balances	1590					$0					$0	$0				$0	$0				$0
8	Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595					$0					$0	$0				$0	$0				$0
9	Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595					$0					$0	$0				$0	$0				$0
9	Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595					$0					$0	$0				$0	$0				$0
10	Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595					$0					$0	$0				$0	$0				$0
	Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	RSVA - Global Adjustment	**1589**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Group 2 Accounts																					
11	Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508					$0					$0	$0				$0	$0				$0
12	Other Regulatory Assets - Sub-Account - Pension Contributions	1508					$0					$0	$0				$0	$0				$0
13	Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508					$0					$0	$0				$0	$0				$0
14	Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508																				
15	Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508																				
16	Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508																				
17	Other Regulatory Assets - Sub-Account - Other [4]	1508					$0					$0	$0				$0	$0				$0
18	Retail Cost Variance Account - Retail	1518					$0					$0	$0				$0	$0				$0
19	Misc. Deferred Debits	1525					$0					$0	$0				$0	$0				$0
20	Renewable Generation Connection Capital Deferral Account	1531																				
21	Renewable Generation Connection OM&A Deferral Account	1532																				
22	Renewable Generation Connection Funding Adder Deferral Account	1533																				
23	Smart Grid Capital Deferral Account	1534																				
24	Smart Grid OM&A Deferral Account	1535																				
25	Smart Grid Funding Adder Deferral Account	1536																				
26	Retail Cost Variance Account - STR	1548					$0					$0	$0				$0	$0				$0
27	Board-Approved CDM Variance Account	1567																				
28	Extra-Ordinary Event Costs	1572					$0					$0	$0				$0	$0				$0
29	Deferred Rate Impact Amounts	1574					$0					$0	$0				$0	$0				$0
30	RSVA - One-time	1582					$0					$0	$0				$0	$0				$0
31	Other Deferred Credits	2425					$0					$0	$0				$0	$0				$0
	Group 2 Sub-Total		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
32	Deferred Payments in Lieu of Taxes	1562					$0					$0	$0				$0	$0				$0
33	PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592					$0					$0	$0				$0	$0				$0
34	PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592					$0					$0	$0				$0	$0				$0
	Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
35	**LRAM Variance Account**	**1568**																				
	Total including Account 1568		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
36	Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[10]	1555					$0					$0	$0				$0	$0				$0
37	Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[10]	1555					$0					$0	$0				$0	$0				$0
38	Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[10]	1555					$0					$0	$0				$0	$0				$0
39	Smart Meter OM&A Variance[10]	1556					$0					$0	$0				$0	$0				$0
40	IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[9]	1575																				
41	Accounting Changes Under CGAAP Balance + Return Component[9]	1576																				
	The following is not included in the total claim but are included on a memo basis:																					
42	Deferred PILs Contra Account [5]	1563					$0					$0	$0				$0	$0				$0
43	PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592					$0					$0	$0				$0	$0				$0
44	Disposition and Recovery of Regulatory Balances[7]	1595					$0					$0	$0				$0	$0				$0



Account Descriptions	Account Number	2007									2008									
		Opening Principal Amounts as of Jan-1-07	Transactions Debit / (Credit) during 2007 excluding interest and adjustments [3]	Board-Approved Disposition during 2007	Adjustments during 2007 - other [2]	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 [2]	Closing Interest Amounts as of Dec-31-07	Opening Principal Amounts as of Jan-1-08	Transactions Debit / (Credit) during 2008 excluding interest and adjustments [3]	Board-Approved Disposition during 2008	Adjustments during 2008 - other [2]	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 [2]	Closing Interest Amounts as of Dec-31-08
Group 1 Accounts																				
LV Variance Account	1550	$0				$0	$0				$0	$0				$0	$0				$0
RSVA - Wholesale Market Service Charge	1580	$0				$0	$0				$0	$0				$0	$0				$0
RSVA - Retail Transmission Network Charge	1584	$0				$0	$0				$0	$0				$0	$0				$0
RSVA - Retail Transmission Connection Charge	1586	$0				$0	$0				$0	$0				$0	$0				$0
RSVA - Power (excluding Global Adjustment)	1588	$0				$0	$0				$0	$0				$0	$0				$0
RSVA - Global Adjustment	1589	$0				$0	$0				$0	$0				$0	$0				$0
Recovery of Regulatory Asset Balances	1590	$0				$0	$0				$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$0				$0	$0				$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$0				$0	$0				$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$0				$0	$0				$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595	$0				$0	$0				$0	$0				$0	$0				$0
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
RSVA - Global Adjustment	**1589**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Group 2 Accounts																				
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$0				$0	$0				$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$0				$0	$0				$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0				$0	$0				$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508																			
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508																			
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508																			
Other Regulatory Assets - Sub-Account - Other [4]	1508	$0				$0	$0				$0	$0				$0	$0				$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0	$0				$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0	$0				$0	$0				$0
Renewable Generation Connection Capital Deferral Account	1531																			
Renewable Generation Connection OM&A Deferral Account	1532																			
Renewable Generation Connection Funding Adder Deferral Account	1533																			
Smart Grid Capital Deferral Account	1534																			
Smart Grid OM&A Deferral Account	1535																			
Smart Grid Funding Adder Deferral Account	1536																			
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567																			
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0	$0				$0	$0				$0
Group 2 Sub-Total		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Deferred Payments in Lieu of Taxes	1562	$0				$0	$0				$0	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0				$0	$0				$0	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0				$0	$0				$0	$0				$0	$0				$0
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LRAM Variance Account	**1568**																			
Total including Account 1568		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[10]	1555	$0				$0	$0				$0	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[10]	1555	$0				$0	$0				$0	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[10]	1555	$0				$0	$0				$0	$0				$0	$0				$0
Smart Meter OM&A Variance[10]	1556	$0				$0	$0				$0	$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[9]	1575																			
Accounting Changes Under CGAAP Balance + Return Component[9]	1576																			
The following is not included in the total claim but are included on a memo basis:																				
Deferred PILs Contra Account [5]	1563	$0				$0	$0				$0	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$0				$0	$0				$0	$0				$0	$0				$0
Disposition and Recovery of Regulatory Balances[7]	1595	$0				$0	$0				$0	$0				$0	$0				$0



Account Descriptions	Account Number	2009									2010									
		Opening Principal Amounts as of Jan-1-09	Transactions Debit / (Credit) during 2009 excluding interest and adjustments [3]	Board-Approved Disposition during 2009	Adjustments during 2009 - other [2]	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 [2]	Closing Interest Amounts as of Dec-31-09	Opening Principal Amounts as of Jan-1-10	Transactions Debit / (Credit) during 2010 excluding interest and adjustments [3]	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	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				$0	$0				$0	$0				$0	$0				$0
RSVA - Wholesale Market Service Charge	1580	$0				$0	$0				$0	$0				$0	$0				$0
RSVA - Retail Transmission Network Charge	1584	$0				$0	$0				$0	$0				$0	$0				$0
RSVA - Retail Transmission Connection Charge	1586	$0				$0	$0				$0	$0				$0	$0				$0
RSVA - Power (excluding Global Adjustment)	1588	$0				$0	$0				$0	$0				$0	$0				$0
RSVA - Global Adjustment	1589	$0				$0	$0				$0	$0				$0	$0				$0
Recovery of Regulatory Asset Balances	1590	$0				$0	$0				$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$0				$0	$0				$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$0				$0	$0				$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$0				$0	$0				$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595	$0				$0	$0				$0	$0				$0	$0				$0
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
RSVA - Global Adjustment	**1589**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Group 2 Accounts																					
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$0				$0	$0				$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$0				$0	$0				$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0				$0	$0				$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508																				
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508																				
Other Regulatory Assets - Sub-Account - Other [4]	1508	$0				$0	$0				$0	$0				$0	$0				$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0	$0				$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0	$0				$0	$0				$0
Renewable Generation Connection Capital Deferral Account	1531					$0	$0				$0	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account	1532					$0	$0				$0	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533					$0	$0				$0	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534					$0	$0				$0	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535					$0	$0				$0	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536					$0	$0				$0	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567										$0					$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0	$0				$0	$0				$0
Group 2 Sub-Total		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Deferred Payments in Lieu of Taxes	1562	$0				$0	$0				$0	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0				$0	$0				$0	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0				$0	$0				$0	$0				$0	$0				$0
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LRAM Variance Account	**1568**															$0					$0
Total including Account 1568		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[10]	1555	$0				$0	$0				$0	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[10]	1555	$0				$0	$0				$0	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[10]	1555	$0				$0	$0				$0	$0				$0	$0				$0
Smart Meter OM&A Variance[10]	1556	$0				$0	$0				$0	$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[9]	1575																				
Accounting Changes Under CGAAP Balance + Return Component[9]	1576																				
The following is not included in the total claim but are included on a memo basis:																					
Deferred PILs Contra Account [5]	1563	$0				$0	$0				$0	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$0				$0	$0				$0	$0				$0	$0				$0
Disposition and Recovery of Regulatory Balances[7]	1595	$0				$0	$0				$0	$0				$0	$0				$0



Account Descriptions	Account Number	2011									2012											
		Opening Principal Amounts as of Jan-1-11	Transactions Debit / (Credit) during 2011 excluding interest and adjustments [3]	Board-Approved Disposition during 2011	Adjustments during 2010 - other [2]	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 [2]	Closing Interest Amounts as of Dec-31-11	Opening Principal Amounts as of Jan-1-12	Transactions Debit / (Credit) during 2012 excluding interest and adjustments [3]	Board-Approved Disposition during 2012	Other [2] Adjustments during Q1 2012	Other [2] Adjustments during Q2 2012	Other [2] Adjustments during Q3 2012	Other [2] Adjustments during Q4 2012	Closing Principal Balance as of Dec-31-12	Opening Interest Amounts as of Jan-1-12	Interest Jan-1 to Dec-31-12	Board-Approved Disposition during 2012	Adjustments during 2012 - other [2]	Closing Interest Amounts as of Dec-31-12
Group 1 Accounts																							
LV Variance Account	1550	$0				$0	$0				$0	$0							$0	$0				$0
RSVA - Wholesale Market Service Charge	1580	$0			-$176,253	-$176,253	$0			-$2,577	-$2,577	-$176,253	-$119,184	-$91,228					-$204,209	-$2,577	-$2,587	-$2,265		-$2,900
RSVA - Retail Transmission Network Charge	1584	$0			$31,277	$31,277	$0			$1,645	$1,645	$31,277	$137,804	$55,949					$113,133	$1,645	$681	$1,956		$369
RSVA - Retail Transmission Connection Charge	1586	$0			$206	$206	$0			$789	$789	$206	$89,520	$22,651					$67,075	$789	$241	$1,017		$13
RSVA - Power (excluding Global Adjustment)	1588	$0			-$112,207	-$112,207	$0			-$2,211	-$2,211	-$112,207	-$16,483	-$66,692					-$61,999	-$2,211	-$1,200	-$1,847		-$1,564
RSVA - Global Adjustment	1589	$0			-$63,869	-$63,869	$0			-$1,557	-$1,557	-$63,869	-$9,509	-$101,441					$28,063	-$1,557	-$156	-$2,644		$930
Recovery of Regulatory Asset Balances	1590	$0				$0	$0				$0	$0							$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2008) [7]	1595	$0				$0	$0				$0	$0							$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2009) [7]	1595	$0				$0	$0				$0	$0							$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2010) [7]	1595	$0				$0	$0				$0	$0							$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2011) [7]	1595	$0	$133,224			$133,224	$0	$7,337			$7,337	$133,224	-$105,681						$27,543	$7,337	$792			$8,129
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$133,224	$0	-$320,847	-$187,623	$0	$7,337	$0	-$3,912	$3,424	-$187,623	-$23,532	-$180,761	$0	$0	$0	$0	-$30,394	$3,424	-$2,229	-$3,782	$0	$4,978
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$133,224	$0	-$256,978	-$123,754	$0	$7,337	$0	-$2,355	$4,982	-$123,754	-$14,023	-$79,320	$0	$0	$0	$0	-$58,458	$4,982	-$2,073	-$1,139	$0	$4,048
RSVA - Global Adjustment	**1589**	$0	$0	$0	-$63,869	-$63,869	$0	$0	$0	-$1,557	-$1,557	-$63,869	-$9,509	-$101,441	$0	$0	$0	$0	$28,063	-$1,557	-$156	-$2,644	$0	$930
Group 2 Accounts																								
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$0				$0	$0				$0	$0							$0	$0				$0
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$0				$0	$0				$0	$0							$0	$0				$0
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0				$0	$0				$0	$0							$0	$0				$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0	$0							$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act [8]	1508	$0				$0	$0				$0	$0							$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	$0				$0	$0				$0	$0							$0	$0				$0
Other Regulatory Assets - Sub-Account - Other [4]	1508	$0				$0	$0				$0	$0							$0	$0				$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0	$0							$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0	$0							$0	$0				$0
Renewable Generation Connection Capital Deferral Account	1531	$0				$0	$0				$0	$0							$0	$0				$0
Renewable Generation Connection OM&A Deferral Account	1532	$0				$0	$0				$0	$0							$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	$0				$0	$0				$0	$0							$0	$0				$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0	$0							$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0	$0							$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0	$0							$0	$0				$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0	$0							$0	$0				$0
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0	$0							$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0	$0							$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0	$0							$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0	$0							$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0	$0							$0	$0				$0
Group 2 Sub-Total		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Deferred Payments in Lieu of Taxes	1562	$0				$0	$0				$0	$0							$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0				$0	$0				$0	$0							$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0				$0	$0				$0	$0							$0	$0				$0
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$0	$133,224	$0	-$320,847	-$187,623	$0	$7,337	$0	-$3,912	$3,424	-$187,623	-$23,532	-$180,761	$0	$0	$0	$0	-$30,394	$3,424	-$2,229	-$3,782	$0	$4,978
LRAM Variance Account	**1568**	$0				$0	$0				$0	$0							$0	$0				$0
Total including Account 1568		$0	$133,224	$0	-$320,847	-$187,623	$0	$7,337	$0	-$3,912	$3,424	-$187,623	-$23,532	-$180,761	$0	$0	$0	$0	-$30,394	$3,424	-$2,229	-$3,782	$0	$4,978
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital [10]	1555	$0				$0	$0				$0	$0							$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries [10]	1555	$0				$0	$0				$0	$0							$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs [10]	1555	$0				$0	$0				$0	$0							$0	$0				$0
Smart Meter OM&A Variance [10]	1556	$0				$0	$0				$0	$0							$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component [9]	1575																		$0	$0				$0
Accounting Changes Under CGAAP Balance + Return Component [9]	1576																		$0	$0				$0
The following is not included in the total claim but are included on a memo basis:																								
Deferred PILs Contra Account [5]	1563	$0				$0	$0				$0	$0							$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$0				$0	$0				$0	$0							$0	$0				$0
Disposition and Recovery of Regulatory Balances [7]	1595	$0				$0	$0				$0	$0	-$71,415						-$71,415	$0	-$5,129			-$5,129



Account Descriptions	Account Number	2013 Principal Disposition during 2013 - instructed by Board	2013 Interest Disposition during 2013 - instructed by Board	2013 Closing Principal Balances as of Dec 31-12 Adjusted for Dispositions during 2013	2013 Closing Interest Balances as of Dec 31-12 Adjusted for Dispositions during 2013	Projected Interest on Dec-31-12 Balances: Projected Interest from Jan 1, 2013 to December 31, 2013 on Dec 31 -12 balance adjusted for disposition during 2013 [6]	Projected Interest on Dec-31-12 Balances: Projected Interest from January 1, 2014 to April 30, 2014 on Dec 31 -12 balance adjusted for disposition during 2013 [6]	Total Claim	2.1.7 RRR As of Dec 31-12	Variance RRR vs. 2012 Balance *(Principal + Interest)*
Group 1 Accounts										
LV Variance Account	1550			$0	$0			$0		$0
RSVA - Wholesale Market Service Charge	1580	-$85,025	-$1,979	-$119,184	-$920	-$1,752	-$584	-$122,441	-$207,109	$0
RSVA - Retail Transmission Network Charge	1584	-$24,761	-$797	$137,894	$1,166	$2,027	$676	$141,763	$113,502	$0
RSVA - Retail Transmission Connection Charge	1586	-$22,517	-$669	$89,591	$682	$1,317	$439	$92,030	$67,088	$0
RSVA - Power (excluding Global Adjustment)	1588	-$45,516	-$1,256	-$16,483	-$308	-$242	-$81	-$17,114	-$63,563	$0
RSVA - Global Adjustment	1589	$37,572	$1,823	-$9,509	-$893	-$140	-$47	-$10,588	$28,994	$0
Recovery of Regulatory Asset Balances	1590			$0	$0			$0		$0
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595			$0	$0			$0		$0
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595			$0	$0			$0		$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595			$0	$0			$0		$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595			$27,543	$8,129	$405	$135	$36,212	$35,672	$0
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$140,247	-$2,879	$109,853	$7,857	$1,615	$538	$119,862	-$25,416	$0
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$177,819	-$4,701	$119,361	$8,749	$1,755	$585	$130,450	-$54,410	$0
RSVA - Global Adjustment	**1589**	$37,572	$1,823	-$9,509	-$893	-$140	-$47	-$10,588	$28,994	$0
Group 2 Accounts										
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508			$0	$0			$0		$0
Other Regulatory Assets - Sub-Account - Pension Contributions	1508			$0	$0			$0		$0
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508			$0	$0			$0		$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508			$0	$0			$0		$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508			$0	$0			$0		$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508			$0	$0			$0		$0
Other Regulatory Assets - Sub-Account - Other [4]	1508			$0	$0			$0		$0
Retail Cost Variance Account - Retail	1518			$0	$0			$0		$0
Misc. Deferred Debits	1525			$0	$0			$0		$0
Renewable Generation Connection Capital Deferral Account	1531			$0	$0			$0		$0
Renewable Generation Connection OM&A Deferral Account	1532			$0	$0			$0		$0
Renewable Generation Connection Funding Adder Deferral Account	1533			$0	$0			$0		$0
Smart Grid Capital Deferral Account	1534			$0	$0			$0		$0
Smart Grid OM&A Deferral Account	1535			$0	$0			$0		$0
Smart Grid Funding Adder Deferral Account	1536			$0	$0			$0		$0
Retail Cost Variance Account - STR	1548			$0	$0			$0		$0
Board-Approved CDM Variance Account	1567			$0	$0			$0		$0
Extra-Ordinary Event Costs	1572			$0	$0			$0		$0
Deferred Rate Impact Amounts	1574			$0	$0			$0		$0
RSVA - One-time	1582			$0	$0			$0		$0
Other Deferred Credits	2425			$0	$0			$0		$0
Group 2 Sub-Total		$0	$0	$0	$0	$0	$0	$0	$0	$0
Deferred Payments in Lieu of Taxes	1562			$0	$0			$0		$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592			$0	$0			$0		$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592			$0	$0			$0		$0
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		-$140,247	-$2,879	$109,853	$7,857	$1,615	$538	$119,862	-$25,416	$0
LRAM Variance Account	**1568**			$0	$0			$0		$0
Total including Account 1568		-$140,247	-$2,879	$109,853	$7,857	$1,615	$538	$119,862	-$25,416	$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[10]	1555			$0	$0			$0		$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[10]	1555			$0	$0			$0		$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[10]	1555			$0	$0			$0		$0
Smart Meter OM&A Variance[10]	1556			$0	$0			$0		$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[9]	1575			$0	$0			$0		$0
Accounting Changes Under CGAAP Balance + Return Component[9]	1576			$0	$0			$0		$0
The following is not included in the total claim but are included on a memo basis:										
Deferred PILs Contra Account [5]	1563			$0	$0			$0		$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592			$0	$0			$0		$0
Disposition and Recovery of Regulatory Balances[7]	1595			-$71,415	-$5,129			-$76,544	-$76,544	$0

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Appendix 2-FB

Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Enabling Improvement Investments

This table will calculate the distributor/provincial shares of the investments entered in Part A of Appendix 2-FA.
Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage.
Rate Riders are not calculated for Test Year as these assets and costs are already in the distributor's rate base/revenue requirement.

		2014 Test Year			2015			2016			2017			2018		
			Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
		Total	6%	94%	Total	6%	94%	Total	6%	94%	Total	6%	94%	Total	6%	94%
Net Fixed Assets (average)		$ 110,700	$ 6,642	$ 104,058	$ 196,800	$ 11,808	$ 184,992	$ 147,600	$ 8,856	$ 138,744	$ 98,400	$ 5,904	$ 92,496	$ 49,200	$ 2,952	$ 46,248
Incremental OM&A (on-going, N/A for Provincial Recovery)		$0	$ -		$0	$ -		$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recovery)		$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA	13%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base			$ 6,642	$ 104,058		$ 11,808	$ 184,992		$ 8,856	$ 138,744		$ 5,904	$ 92,496		$ 2,952	$ 46,248
Deemed ST Debt	4%		$ 266	$ 4,162		$ 472	$ 7,400		$ 354	$ 5,550		$ 236	$ 3,700		$ 118	$ 1,850
Deemed LT Debt	56%		$ 3,720	$ 58,272		$ 6,612	$ 103,596		$ 4,959	$ 77,697		$ 3,306	$ 51,798		$ 1,653	$ 25,899
Deemed Equity	60%		$ 3,985	$ 62,435		$ 7,085	$ 110,995		$ 5,314	$ 83,246		$ 3,542	$ 55,498		$ 1,771	$ 27,749
ST Interest	2.07%		$ 5	$ 86		$ 10	$ 153		$ 7	$ 115		$ 5	$ 77		$ 2	$ 38
LT Interest	3.70%		$ 138	$ 2,156		$ 245	$ 3,833		$ 183	$ 2,875		$ 122	$ 1,917		$ 61	$ 958
ROE	8.98%		$ 358	$ 5,607		$ 636	$ 9,967		$ 477	$ 7,476		$ 318	$ 4,984		$ 159	$ 2,492
Cost of Capital Total			$ 501	$ 7,849		$ 891	$ 13,954		$ 668	$ 10,465		$ 445	$ 6,977		$ 223	$ 3,488
OM&A			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Amortization		$ 24,600	$ 1,476	$ 23,124	$ 49,200	$ 2,952	$ 46,248	$ 49,200	$ 2,952	$ 46,248	$ 49,200	$ 2,952	$ 46,248	$ 49,200	$ 2,952	$ 46,248
Grossed-up PILs			-$ 802	-$ 12,569		-$ 828	-$ 12,977		$ 281	$ 4,410		$ 749	$ 11,739		$ 928	$ 14,543
Revenue Requirement			$ 1,175	$ 18,404		$ 3,014	$ 47,225		$ 3,901	$ 61,123		$ 4,147	$ 64,964		$ 4,103	$ 64,280
Provincial Rate Protection				$ 18,404			$ 47,225			$ 61,123			$ 64,964			$ 64,280
Monthly Amount Paid by IESO				$ 1,534			$ 3,935			$ 5,094			$ 5,414			$ 5,357

Note 1: The difference between the actual costs of approved eligible investments and revenue received from the IESO should be recorded in a variance account. The Board may provide regulatory accounting guidance regarding a variance account either in an individual proceeding or on a generic basis.

Note 2: For the 2014 Test Year, Costs and Revenues of the Direct Benefit are to be included in the test year applicant Rate Base and Revenues.

PILs Calculation

	2014		2015		2016		2017			2018	
Income Tax	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial	Total	Direct Benefit	Provincial	Total	Direct Benefit	Provincial
Net Income - ROE on Rate Base	$ 358	$ 5,607	$ 636	$ 9,967	$ 477	$ 7,476		$ 318	$ 4,984		$ 159	$ 2,492
Amortization (6% DB and 94% P)	$ 1,476	$ 23,124	$ 2,952	$ 46,248	$ 2,952	$ 46,248		$ 2,952	$ 46,248		$ 2,952	$ 46,248
CCA (6% DB and 94% P)	-$ 4,059	-$ 63,591	-$ 5,886	-$ 92,207	-$ 2,648	-$ 41,493		-$ 1,192	-$ 18,672		-$ 536	-$ 8,402
Taxable income	-$ 2,225	-$ 34,860	-$ 2,297	-$ 35,992	$ 781	$ 12,230		$ 2,078	$ 32,560		$ 2,575	$ 40,337
Tax Rate (to be entered)	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%		26.50%	26.50%		26.50%	26.50%
Income Taxes Payable	-$ 589.66	-$ 9,237.99	-$ 608.79	-$ 9,537.77	$ 206.88	$ 3,241.06		$ 550.75	$ 8,628.34		$ 682.30	$ 10,689.43
Gross Up												
Income Taxes Payable	-$ 802.26	-$ 12,568.70	-$ 828.29	-$ 12,976.56	$ 281.46	$ 4,409.60		$ 749.31	$ 11,739.24		$ 928.31	$ 14,543.45
Grossed Up PILs	**-$ 802**	**-$ 12,569**	**-$ 828**	**-$ 12,977**	**$ 281**	**$ 4,410**		**$ 749**	**$ 11,739**		**$ 928**	**$ 14,543**

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Appendix 2-FB

Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Enabling Improvement Investments

This table will calculate the distributor/provincial shares of the investments entered in Part A of Appendix 2-FA.
Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage.
Rate Riders are not calculated for Test Year as these assets and costs are already in the distributor's rate base/revenue requirement.

		2014	2015	2016	2017	2018
Net Fixed Assets						
Enter applicable amortization in years:	5					
Opening Gross Fixed Assets			$ 246,000	$ 246,000	$ 246,000	$ 246,000
Gross Capital Additions		$ 246,000	$ -	$ -	$ -	$ -
Closing Gross Fixed Assets		$ 246,000	$ 246,000	$ 246,000	$ 246,000	$ 246,000
Opening Accumulated Amortization			$ 24,600	$ 73,800	$ 123,000	$ 172,200
Current Year Amortization (before additions)			$ 49,200	$ 49,200	$ 49,200	$ 49,200
Additions (half year)		$ 24,600	$ -	$ -	$ -	$ -
Closing Accumulated Amortization		$ 24,600	$ 73,800	$ 123,000	$ 172,200	$ 221,400
Opening Net Fixed Assets		$ -	$ 221,400	$ 172,200	$ 123,000	$ 73,800
Closing Net Fixed Assets		$ 221,400	$ 172,200	$ 123,000	$ 73,800	$ 24,600
Average Net Fixed Assets		$ 110,700	$ 196,800	$ 147,600	$ 98,400	$ 49,200

		2014	2015	2016	2017	2018
UCC for PILs Calculation						
Opening UCC			$ 178,350	$ 80,258	$ 36,116	$ 16,252
Capital Additions (from Appendix 2-FA)		$ 246,000	$ -	$ -	$ -	$ -
UCC Before Half Year Rule		$ 246,000	$ 178,350	$ 80,258	$ 36,116	$ 16,252
Half Year Rule (1/2 Additions - Disposals)		$ 123,000	$ -	$ -	$ -	$ -
Reduced UCC		$ 123,000	$ 178,350	$ 80,258	$ 36,116	$ 16,252
CCA Rate Class (to be entered)	50	50	50	50	50	50
CCA Rate (to be entered)	55%	55%	55%	55%	55%	55%
CCA		$ 67,650	$ 98,093	$ 44,142	$ 19,864	$ 8,939
Closing UCC		$ 178,350	$ 80,258	$ 36,116	$ 16,252	$ 7,313

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Appendix 2-FC

Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Expansion Investments

This table will calculate the distributor/provincial shares of the investments entered in Part B of Appendix 2-FA.

Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage.

Rate Riders are not calculated for Test Year as these assets and costs are already in the distributors rate base.

		2014 Test Year			2015			2016			2017			2018		
			Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
		Total	17%	83%	Total	17%	83%	Total	17%	83%	Total	17%	83%	Total	17%	83%
Net Fixed Assets (average)		$ 649,495	$ 110,414	$ 539,081	$ 1,840,880	$ 312,950	$ 1,527,930	$ 2,774,060	$ 471,590	$ 2,302,470	$ 3,538,640	$ 601,569	$ 2,937,071	$ 4,267,220	$ 725,427	$ 3,541,793
Incremental OM&A (on-going, N/A for Provincial Recovery)		$0	$ -		$0	$ -		$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recovery)		$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA	13%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base			$ 110,414	$ 539,081		$ 312,950	$ 1,527,930		$ 471,590	$ 2,302,470		$ 601,569	$ 2,937,071		$ 725,427	$ 3,541,793
Deemed ST Debt	4%		$ 4,417	$ 21,563		$ 12,518	$ 61,117		$ 18,864	$ 92,099		$ 24,063	$ 117,483		$ 29,017	$ 141,672
Deemed LT Debt	56%		$ 61,832	$ 301,885		$ 175,252	$ 855,641		$ 264,091	$ 1,289,383		$ 336,879	$ 1,644,760		$ 406,239	$ 1,983,404
Deemed Equity	60%		$ 66,248	$ 323,449		$ 187,770	$ 916,758		$ 282,954	$ 1,381,482		$ 360,941	$ 1,762,243		$ 435,256	$ 2,125,076
ST Interest	2.07%		$ 91	$ 446		$ 259	$ 1,265		$ 390	$ 1,906		$ 498	$ 2,432		$ 601	$ 2,933
LT Interest	3.70%		$ 2,288	$ 11,170		$ 6,484	$ 31,659		$ 9,771	$ 47,707		$ 12,465	$ 60,856		$ 15,031	$ 73,386
ROE	8.98%		$ 5,949	$ 29,046		$ 16,862	$ 82,325		$ 25,409	$ 124,057		$ 32,413	$ 158,249		$ 39,086	$ 190,832
Cost of Capital Total			$ 8,328	$ 40,662		$ 23,605	$ 115,249		$ 35,571	$ 173,671		$ 45,375	$ 221,537		$ 54,718	$ 267,150
OM&A			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Amortization		$ 26,510	$ 4,507	$ 22,003	$ 76,220	$ 12,957	$ 63,263	$ 117,420	$ 19,961	$ 97,459	$ 153,420	$ 26,081	$ 127,339	$ 189,420	$ 32,201	$ 157,219
Grossed-up PILs			$ 520	$ 2,539		$ 1,668	$ 8,142		$ 2,951	$ 14,407		$ 4,342	$ 21,199		$ 5,881	$ 28,714
Revenue Requirement			$ 13,355	$ 65,204		$ 38,230	$ 186,653		$ 58,483	$ 285,536		$ 75,798	$ 370,075		$ 92,800	$ 453,083
Provincial Rate Protection				$ 65,204			$ 186,653			$ 285,536			$ 370,075			$ 453,083
Monthly Amount Paid by IESO				$ 5,434			$ 15,554			$ 23,795			$ 30,840			$ 37,757

Note 1: The difference between the actual costs of approved eligible investments and revenue received from the IESO should be recorded in a variance account. The Board may provide regulatory accounting guidance regarding a variance account either in an individual proceeding or on a generic basis.

Note 2: For the 2014 Test Year, Costs and Revenues of the Direct Benefit are to be included in the test year applicant Rate Base and Revenues.

PILs Calculation

Income Tax	2014 Direct Benefit	2014 Provincial	2015 Direct Benefit	2015 Provincial	2016 Direct Benefit	2016 Provincial	2017 Total	2017 Direct Benefit	2017 Provincial	2018 Total	2018 Direct Benefit	2018 Provincial
Net Income - ROE on Rate Base	$ 5,949	$ 29,046	$ 16,862	$ 82,325	$ 25,409	$ 124,057		$ 32,413	$ 158,249		$ 39,086	$ 190,832
Amortization (17% DB and 83% P)	$ 4,507	$ 22,003	$ 12,957	$ 63,263	$ 19,961	$ 97,459		$ 26,081	$ 127,339		$ 32,201	$ 157,219
CCA (17% DB and 83% P)	-$ 9,013	-$ 44,007	-$ 25,194	-$ 123,005	-$ 37,186	-$ 181,556		-$ 46,451	-$ 226,792		-$ 54,975	-$ 268,408
Taxable income	$ 1,442	$ 7,042	$ 4,625	$ 22,583	$ 8,184	$ 39,959		$ 12,043	$ 58,796		$ 16,312	$ 79,642
Tax Rate (to be entered)	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%		26.50%	26.50%		26.50%	26.50%
Income Taxes Payable	$ 382.24	$ 1,866.23	$ 1,225.73	$ 5,984.45	$ 2,168.88	$ 10,589.23		$ 3,191.29	$ 15,580.99		$ 4,322.73	$ 21,105.11
Gross Up												
Income Taxes Payable	$ 520.05	$ 2,539.09	$ 1,667.66	$ 8,142.10	$ 2,950.86	$ 14,407.12		$ 4,341.89	$ 21,198.63		$ 5,881.27	$ 28,714.44
Grossed Up PILs	**$ 520**	**$ 2,539**	**$ 1,668**	**$ 8,142**	**$ 2,951**	**$ 14,407**		**$ 4,342**	**$ 21,199**		**$ 5,881**	**$ 28,714**

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Appendix 2-FC

Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Expansion Investments

This table will calculate the distributor/provincial shares of the investments entered in Part B of Appendix 2-FA.

Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage.

Rate Riders are not calculated for Test Year as these assets and costs are already in the distributors rate base.

Net Fixed Assets		**2014**	**2015**	**2016**	**2017**	**2018**
Enter applicable amortization in years:	25					
Opening Gross Fixed Assets			$ 1,325,500	$ 2,485,500	$ 3,385,500	$ 4,285,500
Gross Capital Additions	Note: Includes 2013 and 2014 REG Expansion Capital Assets	$ 1,325,500	$ 1,160,000	$ 900,000	$ 900,000	$ 900,000
Closing Gross Fixed Assets		$ 1,325,500	$ 2,485,500	$ 3,385,500	$ 4,285,500	$ 5,185,500
Opening Accumulated Amortization			$ 26,510	$ 102,730	$ 220,150	$ 373,570
Current Year Amortization (before additions)			$ 53,020	$ 99,420	$ 135,420	$ 171,420
Additions (half year)		$ 26,510	$ 23,200	$ 18,000	$ 18,000	$ 18,000
Closing Accumulated Amortization		$ 26,510	$ 102,730	$ 220,150	$ 373,570	$ 562,990
Opening Net Fixed Assets		$ -	$ 1,298,990	$ 2,382,770	$ 3,165,350	$ 3,911,930
Closing Net Fixed Assets		$ 1,298,990	$ 2,382,770	$ 3,165,350	$ 3,911,930	$ 4,622,510
Average Net Fixed Assets		$ 649,495	$ 1,840,880	$ 2,774,060	$ 3,538,640	$ 4,267,220

UCC for PILs Calculation		**2014**	**2015**	**2016**	**2017**	**2018**
Opening UCC			$ 1,272,480	$ 2,284,282	$ 2,965,539	$ 3,592,296
Capital Additions (from Appendix 2-FA)		$ 1,325,500	$ 1,160,000	$ 900,000	$ 900,000	$ 900,000
UCC Before Half Year Rule		$ 1,325,500	$ 2,432,480	$ 3,184,282	$ 3,865,539	$ 4,492,296
Half Year Rule (1/2 Additions - Disposals)		$ 662,750	$ 580,000	$ 450,000	$ 450,000	$ 450,000
Reduced UCC		$ 662,750	$ 1,852,480	$ 2,734,282	$ 3,415,539	$ 4,042,296
CCA Rate Class (to be entered)	47	47	47	47	47	47
CCA Rate (to be entered)	8%	8%	8%	8%	8%	8%
CCA		$ 53,020	$ 148,198	$ 218,743	$ 273,243	$ 323,384
Closing UCC		$ 1,272,480	$ 2,284,282	$ 2,965,539	$ 3,592,296	$ 4,168,912

OPA Conservation & Demand Management Programs

Annual Results at the End-User Level

For: Haldimand County Hydro Inc.

Net Summer Peak Demand Savings (MW)

#	Program Year	Results Status	2006	2007	2008	2009	2010	2011	2012	2013	2014
1	2006 Programs	Final	0.7391	0.0782	0.0782	0.0782	0.0782	0.0782	0.0728	0.0728	0.0569
2	2007 Programs	Final	0.0000	1.3136	0.2723	0.2118	0.2118	0.1564	0.1516	0.1516	0.1516
3	2008 Programs	Final	0.0000	0.0000	1.6594	0.3684	0.3684	0.3684	0.3650	0.3650	0.3596
4	2009 Programs	Final	0.0000	0.0000	0.0000	1.7581	0.6930	0.6930	0.6917	0.6835	0.6649
5	2010 Programs	Final	0.0000	0.0000	0.0000	0.0000	1.3624	0.4655	0.4653	0.4643	0.4547
Total			**0.7391**	**1.3918**	**2.0099**	**2.4165**	**2.7137**	**1.7614**	**1.7464**	**1.7373**	**1.6877**

Net Energy Savings (MWh)

#	Program Year	Results Status	2006	2007	2008	2009	2010	2011	2012	2013	2014
1	2006 Programs	Final	1,615	1,615	1,615	1,615	281	281	257	257	241
2	2007 Programs	Final	0	2,604	2,016	1,943	1,943	838	815	815	815
3	2008 Programs	Final	0	0	1,599	1,151	1,151	1,151	1,074	1,074	995
4	2009 Programs	Final	0	0	0	3,158	2,971	2,971	2,970	2,915	2,773
5	2010 Programs	Final	0	0	0	0	1,703	1,370	1,368	1,367	1,311
Total			**1,615**	**4,219**	**5,231**	**7,867**	**8,048**	**6,611**	**6,483**	**6,427**	**6,135**

Gross Summer Peak Demand Savings (MW)

#	Program Year	Results Status	2006	2007	2008	2009	2010	2011	2012	2013	2014
1	2006 Programs	Final	0.7535	0.0926	0.0926	0.0926	0.0926	0.0926	0.0866	0.0866	0.0690
2	2007 Programs	Final	0.0000	4.2791	1.2238	0.7199	0.7199	0.6610	0.6306	0.6306	0.6306
3	2008 Programs	Final	0.0000	0.0000	1.8363	0.5213	0.5213	0.5213	0.5125	0.5125	0.5006
4	2009 Programs	Final	0.0000	0.0000	0.0000	2.0519	0.9848	0.9848	0.9818	0.9656	0.9312
5	2010 Programs	Final	0.0000	0.0000	0.0000	0.0000	1.6429	0.7463	0.7463	0.7436	0.7231
Total			**0.7535**	**4.3717**	**3.1528**	**3.3858**	**3.9616**	**3.0060**	**2.9578**	**2.9389**	**2.8545**

Gross Energy Savings (MWh)

#	Program Year	Results Status	2006	2007	2008	2009	2010	2011	2012	2013	2014
1	2006 Programs	Final	1,804	1,804	1,804	1,804	321	321	294	294	277
2	2007 Programs	Final	0	8,171	3,319	2,709	2,709	1,604	1,532	1,532	1,532
3	2008 Programs	Final	0	0	2,841	2,260	2,260	2,260	2,062	2,061	1,885
4	2009 Programs	Final	0.0000	0.0000	0.0000	4,608.0835	4,374.7758	4,374.7758	4,371.7466	4,265.4859	3,999.3119
5	2010 Programs	Final	0	0	0	0	2,867	2,544	2,543	2,541	2,431
Total			**1,804**	**9,975**	**7,964**	**11,381**	**12,532**	**11,103**	**10,804**	**10,693**	**10,125**

OPA-Contracted Province-Wide CDM Programs FINAL 2011 Results

LDC: Haldimand County Hydro Inc.

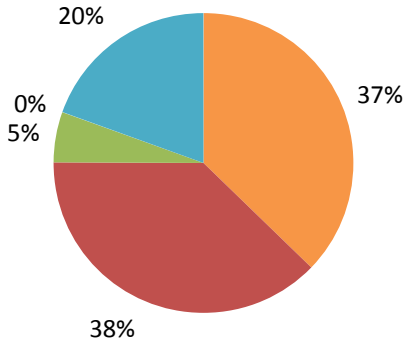
FINAL 2011 Progress to Targets	Incremental 2011	Scenario 1: % of Target Achieved	Scenario 2: % of Target Achieved
Net Annual Peak Demand Savings (MW)	0.4	**11.9%**	**13.6%**
Net Cumulative Energy Savings (GWh)	1.6	**46.7%**	**46.7%**

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

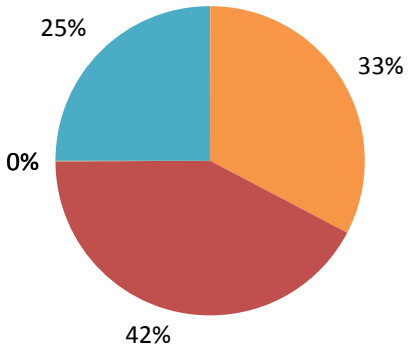
Scenario 2 = Assumes that demand response resources remain in your territory until 2014

Achievement by Sector

2011 Incremental Peak Demand Savings (MW)



2011 Incremental Energy Savings (GWh)

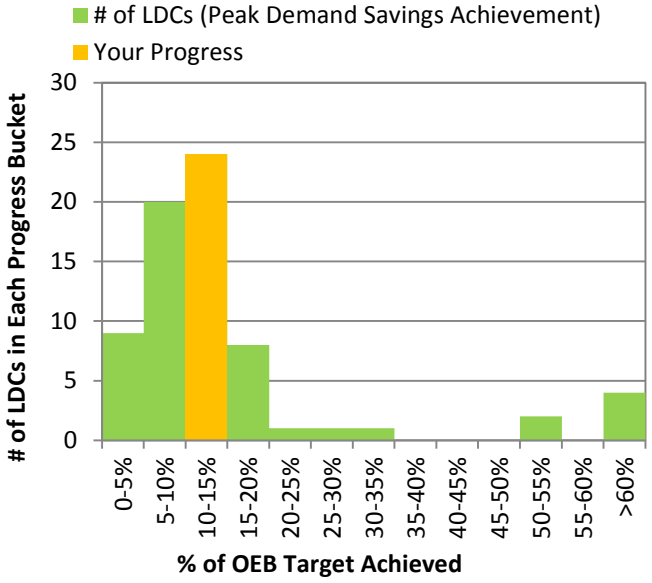


Consumer Program Total
Business Program Total
Industrial Program Total
Home Assistance Program Total
Pre-2011 Programs completed in 2011 Total

Comparison: Your Achievement vs. LDC Community Achievement

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

% of OEB Peak Demand Savings Target Achieved



% of OEB Energy Savings Target Achieved

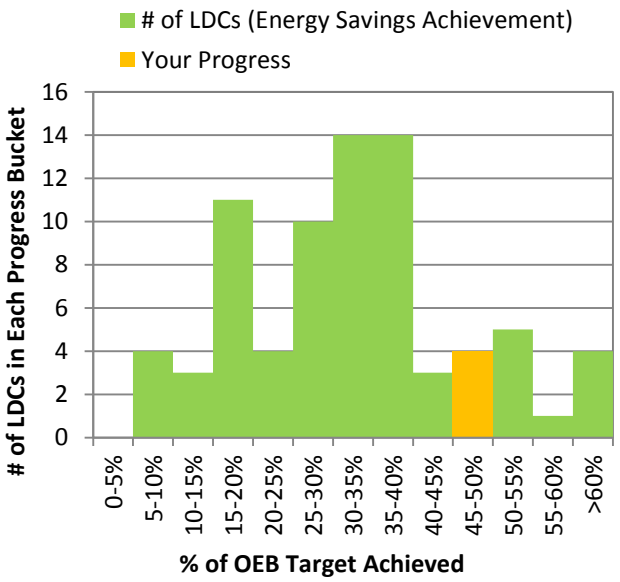


Table 1: Participation[1]

#	Initiative	Unit	Uptake/ Participation Units
Consumer Program			
1	Appliance Retirement	Appliances	270
2	Appliance Exchange	Appliances	22
3	HVAC Incentives	Equipment	375
4	Conservation Instant Coupon Booklet	Products	2,155
5	Bi-Annual Retailer Event	Products	3,694
6	Retailer Co-op	Products	0
7	Residential Demand Response	Devices	19
8	Residential New Construction	Houses	0
Business Program			
9	Efficiency: Equipment Replacement	Projects	4
10	Direct Install Lighting	Projects	44
11	Existing Building Commissioning Incentive	Buildings	0
12	New Construction and Major Renovation Incentive	Buildings	1
13	Energy Audit	Audits	0
14	Commercial Demand Response (part of the Residential program schedule)	Devices	0
15	Demand Response 3 (part of the Industrial program schedule)	Facilities	0
Industrial Program			
16	Process & System Upgrades	Projects[2]	0
17	Monitoring & Targeting	Projects[3]	0
18	Energy Manager	Managers[2 3]	0
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Projects	0
20	Demand Response 3	Facilities	1
Home Assistance Program			
21	Home Assistance Program	Homes	0
Pre 2011 Programs Completed in 2011			
22	Electricity Retrofit Incentive Program	Projects	3
23	High Performance New Construction	Projects	2
24	Toronto Comprehensive	Projects	0
25	Multifamily Energy Efficiency Rebates	Projects	0
26	Data Centre Incentive Program	Projects	0
27	EnWin Green Suites	Projects	0

[1] *Please see "Methodology" tab for more information regarding attributing savings to LDCs*

[2] *Results are based on completed incentive projects (see "Methodology" tab for more information)*

[3] *Includes: Roving Energy Managers, Key Account Managers and Embedded Energy Managers if projects are completed in 2011*

Table 5: Summarized Program Results

Program	Gross Savings			Net Savings		Contribution to Targets	
	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)		Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program Total	228	730,141		144	511,385	132	2,044,221
Business Program Total	188	917,729		147	660,315	132	2,600,803
Industrial Program Total	25	1,237		21	1,237	0	1,237
Home Assistance Program Total	0	0		0	0	0	0
Pre-2011 Programs completed in 2011 Total	151	779,717		76	390,806	76	1,563,224
Total OPA Contracted Province-Wide CDM Programs	**591**	**2,428,824**		**387**	**1,563,743**	**340**	**6,209,485**

#	Initiative	Realization Rate		Gross Savings		Net-to-Gross Ratio		Net Savings		Contribution to Targets	
		Peak Demand Savings	Energy Savings	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Peak Demand Savings	Energy Savings	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program											
1	Appliance Retirement	100%	100%	31	225,490	52%	52%	16	115,815	16	463,260
2	Appliance Exchange	100%	100%	4	5,080	52%	52%	2	2,618	1	9,156
3	HVAC Incentives	100%	100%	171	311,736	61%	60%	103	186,931	103	747,724
4	Conservation Instant Coupon Booklet	100%	100%	4	73,672	114%	111%	5	81,297	5	325,189
5	Bi-Annual Retailer Event	100%	100%	6	114,163	113%	110%	7	124,723	7	498,892
6	Retailer Co-op	-	-	0	0	-	-	0	0	0	0
7	Residential Demand Response	0%	0%	11	0	-	-	11	0	0	0
8	Residential New Construction	-	-	0	0	-	-	0	0	0	0
Business Program											
9	Efficiency: Equipment Replacement	101%	116%	101	613,568	70%	72%	70	435,855	70	1,743,418
10	Direct Install Lighting	108%	90%	57	168,900	93%	93%	61	156,830	47	586,862
11	Existing Building Commissioning Incentive	-	-	0	0	-	-	0	0	0	0
12	New Construction and Major Renovation Incentive	-	-	30	135,262	50%	50%	15	67,631	15	270,523
13	Energy Audit	-	-	0	0	-	-	0	0	0	0
14	Commercial Demand Response (part of the Residential program schedule)	0%	0%	0	0	-	-	0	0	0	0
15	Demand Response 3 (part of the Industrial program schedule)	76%	100%	0	0	n/a	n/a	0	0	0	0
Industrial Program											
16	Process & System Upgrades	-	-	0	0	-	-	0	0	0	0
17	Monitoring & Targeting	-	-	0	0	-	-	0	0	0	0
18	Energy Manager	-	-	0	0	-	-	0	0	0	0
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	-	-	0	0	-	-	0	0	0	0
20	Demand Response 3	84%	100%	25	1,237	n/a	n/a	21	1,237	0	1,237
Home Assistance Program											
21	Home Assistance Program	-	-	0	0	-	-	0	0	0	0
Pre-2011 Programs completed in 2011											
22	Electricity Retrofit Incentive Program	77%	77%	8	47,364	52%	52%	4	24,629	4	98,518
23	High Performance New Construction	100%	100%	143	732,353	50%	50%	71	366,177	71	1,464,706
24	Toronto Comprehensive	-	-	0	0	-	-	0	0	0	0
25	Multifamily Energy Efficiency Rebates	-	-	0	0	-	-	0	0	0	0
26	Data Centre Incentive Program	-	-	0	0	-	-	0	0	0	0
27	EnWin Green Suites	-	-	0	0	-	-	0	0	0	0

Assumes demand response resources have a persistence of 1 year

Progress Towards CDM Targets

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

Yellow cells are intended for the LDC to input information to complete their OEB Reporting Template.

Table 6: Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	0.39	0.36	0.36	0.34
2012				
2013				
2014				0.00
Verified Net Annual Peak Demand Savings Persisting in 2014:				0.34
Haldimand County Hydro Inc. 2014 Annual CDM Capacity Target:				2.85
Verified Portion of Peak Demand Savings Target Achieved in 2014(%):				11.92%
LDC Milestone submitted for 2011				-%
Variance				

Table 7: Net Energy Savings at the End User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	1.56	1.56	1.56	1.52	6.21
2012					
2013					
2014					
Verified Net Cumulative Energy Savings 2011-2014:					6.21
Haldimand County Hydro Inc. 2011-2014 Cumulative CDM Energy Target:					13.3
Verified Portion of Cumulative Energy Target Achieved (%):					46.69%
LDC Milestone submitted for 2011					-%
Variance					

OPA-Contracted Province-Wide CDM Programs FINAL 2012 Results

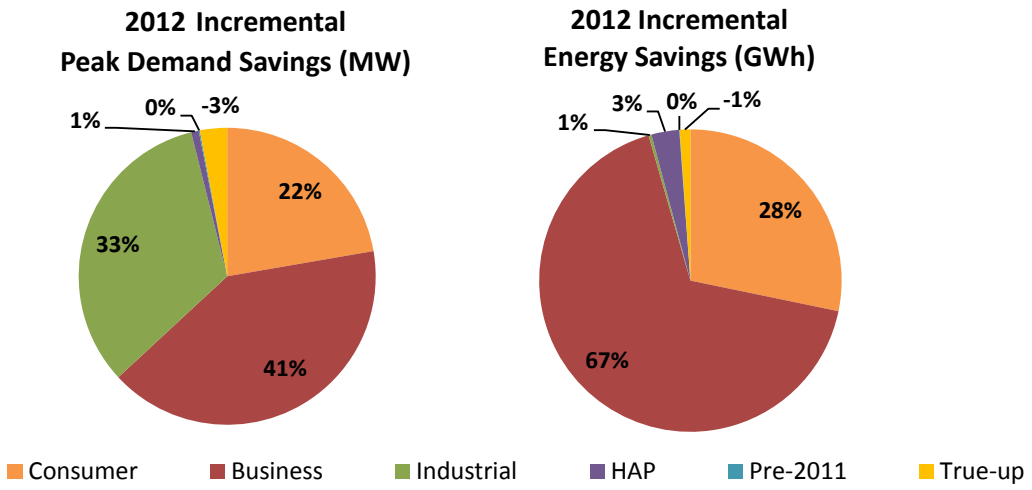
LDC: Haldimand County Hydro Inc.

FINAL 2012 Progress to Targets	2012 Incremental	Program-to-Date Progress to Target (Scenario 1)	Scenario 1: % of Target Achieved	Scenario 2: % of Target Achieved
Net Annual Peak Demand Savings (MW)	0.4	0.6	**20.0%**	**24.8%**
Net Energy Savings (GWh)	1.0	9.2	**69.3%**	**69.4%**

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

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

Achievement by Sector



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

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

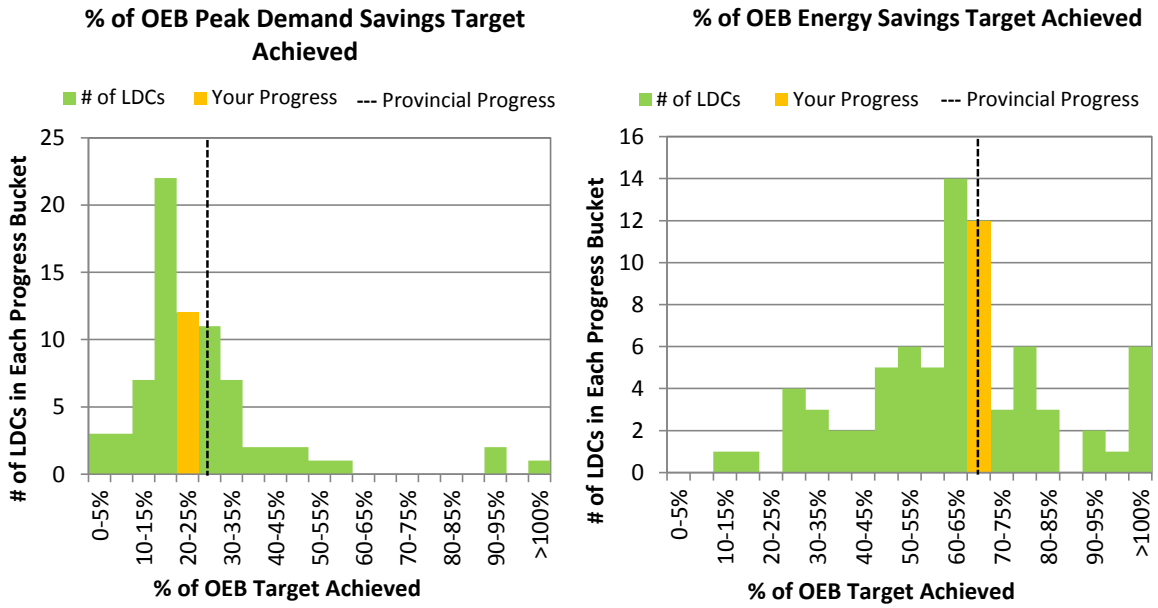


Table 1: **Haldimand County Hydro Inc.** Initiative and Program Level Savings by Year (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
														2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	270	154			16	9			115,815	61,427			25	647,542
Appliance Exchange	Appliances	22	36			2	5			2,618	9,228			6	36,839
HVAC Incentives	Equipment	375	251			103	57			186,931	98,468			161	1,043,128
Conservation Instant Coupon Booklet	Items	2,155	131			5	1			81,297	5,934			6	342,992
Bi-Annual Retailer Event	Items	3,694	4,503			7	6			124,723	113,664			13	839,883
Retailer Co-op	Items	0	0			0	0			0	0			0	0
Residential Demand Response (switch/pstat)	Devices	19	19			11	9			0	55			0	55
Residential Demand Response (IHD)	Devices	0	0			0				0					
Residential New Construction	Homes	0	1			0	0			0	415			0	1,245
Consumer Program Total						**144**	**87**			**511,385**	**289,191**			**211**	**2,911,684**
Business Program															
Retrofit	Projects	4	20			70	109			435,855	503,091			179	3,252,692
Direct Install Lighting	Projects	44	50			61	40			156,830	149,154			87	1,034,324
Building Commissioning	Buildings	0	0			0	0			0	0			0	0
New Construction	Buildings	1	2			15	11			67,631	36,709			26	380,650
Energy Audit	Audits	0	0			0	0			0	0			0	0
Small Commercial Demand Response	Devices	0	0			0	0			0	0			0	0
Small Commercial Demand Response (IHD)	Devices	0	0			0				0				0	0
Demand Response 3	Facilities	0	0			0	0			0	0			0	0
Business Program Total						**147**	**160**			**660,315**	**688,954**			**292**	**4,667,667**
Industrial Program															
Process & System Upgrades	Projects	0	0			0	0			0	0			0	0
Monitoring & Targeting	Projects	0	0			0	0			0	0			0	0
Energy Manager	Projects	0	0			0	0			0	0			0	0
Retrofit	Projects	0				0				0				0	0
Demand Response 3	Facilities	1	2			21	129			1,237	3,114			0	4,351
Industrial Program Total						**21**	**129**			**1,237**	**3,114**			**0**	**4,351**
Home Assistance Program															
Home Assistance Program	Homes	0	33			0	3			0	30,560			3	91,679
Home Assistance Program Total						**0**	**3**			**0**	**30,560**			**3**	**91,679**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	3	0			4	0			24,629	0			4	98,518
High Performance New Construction	Projects	2	0			71	0			366,177	465			72	1,466,100
Toronto Comprehensive	Projects	0	0			0	0			0	0			0	0
Multifamily Energy Efficiency Rebates	Projects	0	0			0	0			0	0			0	0
LDC Custom Programs	Projects	0	0			0	0			0	0			0	0
Pre-2011 Programs completed in 2011 Total						**76**	**0**			**390,806**	**465**			**76**	**1,564,618**
Other															
Program Enabled Savings	Projects	0	0			0	0			0	0			0	0
Time-of-Use Savings	Homes														
Other Total							**0**				**0**			**0**	**0**
Adjustments to Previous Year's Verified Results							**-12**				**-5,042**			**-12**	**-20,168**
Energy Efficiency Total						**356**	**242**			**1,562,506**	**1,009,115**			**582**	**9,235,592**
Demand Response Total (Scenario 1)						**32**	**138**			**1,237**	**3,169**			**0**	**4,406**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**387**	**368**			**1,563,743**	**1,007,242**			**570**	**9,219,830**
													Full OEB Target:	**2,850**	**13,300,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**20.0%**	**69.3%**

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

Due to the limited timeframe of data, which didn't include the summer months, 2012 IHD results have been deemed inconclusive. The IHD line item on the 2012 annual report will be left blank. Once a full year of data is available (2013 evaluation), and the savings are quantified, 2012 results will be updated to reflect the quantified savings.

Table 2: Adjustments to **Haldimand County Hydro Inc.** Verified Results due to Errors or Omissions (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program															
Appliance Retirement	Appliances	0				0				0				0	0
Appliance Exchange	Appliances	0				0				0				0	0
HVAC Incentives	Equipment	-52				-14				-25,122				-14	-100,489
Conservation Instant Coupon Booklet	Items	35				0				1,170				0	4,680
Bi-Annual Retailer Event	Items	347				0				9,266				0	37,066
Retailer Co-op	Items	0				0				0				0	0
Residential Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Residential Demand Response (IHD)	Devices	0				0				0				0	0
Residential New Construction	Homes	0				0				0				0	0
Consumer Program Total						**-14**				**-14,686**				**-14**	**-58,744**
Business Program															
Retrofit	Projects	2				6				31,596				6	126,384
Direct Install Lighting	Projects	0				0				0				0	0
Building Commissioning	Buildings	0				0				0				0	0
New Construction	Buildings	2				-4				-21,210				-4	-84,839
Energy Audit	Audits	0				0				0				0	0
Small Commercial Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Small Commercial Demand Response (IHD)	Devices	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Business Program Total						**2**				**10,386**				**2**	**41,545**
Industrial Program															
Process & System Upgrades	Projects	0				0				0				0	0
Monitoring & Targeting	Projects	0				0				0				0	0
Energy Manager	Projects	0				0				0				0	0
Retrofit	Projects	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Industrial Program Total						**0**				**0**				**0**	**0**
Home Assistance Program															
Home Assistance Program	Homes	0				0				0				0	0
Home Assistance Program Total						**0**				**0**				**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	0				0				0				0	0
High Performance New Construction	Projects	0				0				-742				0	-2,970
Toronto Comprehensive	Projects	0				0				0				0	0
Multifamily Energy Efficiency Rebates	Projects	0				0				0				0	0
LDC Custom Programs	Projects	0				0				0				0	0
Pre-2011 Programs completed in 2011 Total						**0**				**-742**				**0**	**-2,970**
Other															
Program Enabled Savings	Projects	0				0				0				0	0
Time-of-Use Savings	Homes														
Other Total						**0**				**0**				**0**	**0**
Adjustments to Previous Year's Verified Results						**-12**				**-5,042**				**-12**	**-20,168**

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

Table 3: Haldimand County Hydro Inc. Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement		1.00				0.46				1.00				0.47		
Appliance Exchange		1.00				0.52				1.00				0.52		
HVAC Incentives		1.00				0.50				1.00				0.49		
Conservation Instant Coupon Booklet		1.00				1.00				1.00				1.05		
Bi-Annual Retailer Event		1.00				0.91				1.00				0.92		
Retailer Co-op		n/a				n/a				n/a				n/a		
Residential Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Residential Demand Response (IHD)		n/a				n/a				n/a				n/a		
Residential New Construction		3.83				0.49				2.81				0.49		
Business Program																
Retrofit		0.98				0.77				1.15				0.79		
Direct Install Lighting		0.69				0.94				0.85				0.94		
Building Commissioning		n/a				n/a				n/a				n/a		
New Construction		1.00				0.49				1.00				0.49		
Energy Audit		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (IHD)		n/a				n/a				n/a				n/a		
Demand Response 3*		n/a				n/a				n/a				n/a		
Industrial Program																
Process & System Upgrades		n/a				n/a				n/a				n/a		
Monitoring & Targeting		n/a				n/a				n/a				n/a		
Energy Manager		n/a				n/a				n/a				n/a		
Retrofit																
Demand Response 3*		n/a				n/a				n/a				n/a		
Home Assistance Program																
Home Assistance Program		0.06				1.00				1.00				1.00		
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program		n/a				n/a				n/a				n/a		
High Performance New Construction		1.00				0.50				1.00				0.50		
Toronto Comprehensive		n/a				n/a				n/a				n/a		
Multifamily Energy Efficiency Rebates		n/a				n/a				n/a				n/a		
LDC Custom Programs		n/a				n/a				n/a				n/a		
Other																
Program Enabled Savings		n/a				n/a				n/a				n/a		
Time-of-Use Savings		n/a				n/a				n/a				n/a		

Progress Towards CDM Targets

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

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

Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	0.4	0.4	0.4	0.3
2012 - Verified		0.4	0.2	0.2
2013				
2014				
Verified Net Annual Peak Demand Savings Persisting in 2014:				0.6
Haldimand County Hydro Inc. 2014 Annual CDM Capacity Target				2.9
Verified Portion of Peak Demand Savings Target Achieved in 2014(%):				20.0%

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

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	1.6	1.6	1.6	1.5	6.2
2012 - Verified		1.0	1.0	1.0	3.0
2013					
2014					
Verified Net Cumulative Energy Savings 2011-2014:					9.2
Haldimand County Hydro Inc. 2011-2014 Annual CDM Energy Target					13.3
Verified Portion of Cumulative Energy Target Achieved (%):					69.3%

*2011 energy adjustments included in cumulative energy savings.

INDECO
Strategic Solutions for a Changing World™

Haldimand County Hydro 2011-2012 LRAMVA



Haldimand County Hydro Inc. lost revenue related to Conservation and Demand Management

2011-2012



This document was prepared for Haldimand County Hydro Inc. by IndEco Strategic Consulting Inc.

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27 September 2013

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Introduction

The Lost Revenue Adjustment Mechanism (LRAM) was developed to remove the disincentive to electricity local distribution companies (LDCs) from conservation and demand management (CDM) programs. CDM programs are designed to provide energy savings and peak demand reductions for the customers of LDCs, which would directly impact the LDC's revenue. The LRAM allows LDCs to be compensated for any lost revenue that may occur due to CDM programs in the LDC's service territory.

For the 2011-2014 CDM period, the Ontario Energy Board (OEB) has authorized LDCs to establish an LRAM variance account (LRAMVA) to capture the impact of CDM programs on the revenue of LDCs. The variance in the LRAMVA is between the lost revenue due to independently verified load impacts of CDM and the lost revenue from any CDM impacts an LDC may have included in the LDC's load forecast.[1]

Haldimand County Hydro has contracted with the Ontario Power Authority (OPA) to offer a suite of CDM programs to customers in a variety of rate classes for the 2011-2014 period. The CDM Guidelines (Appendix A) show that LDCs with a cost of service application in 2010 were entitled to claim lost revenues from 2011 programs as part of their 2013 IRM applications, and lost revenues from 2012 programs and persisting losses from 2011 programs in 2012 as part of their 2014 IRM application..

Haldimand County Hydro did not submit a claim for lost revenues from 2011 programs in its 2013 IRM application. This report involves a determination of the variance account balance for the following revenue losses:

- Lost revenues in 2011 related to programs offered in 2011
- Lost revenues in 2012 related to programs offered in 2011
- Lost revenues in 2012 related to programs offered in 2012.

The carrying charges on the above lost revenues through December 2012 are also reported.

[1] *Guidelines for Electricity Distributor Conservation and Demand Management*. Ontario Energy Board. April 26, 2012 (EB-2012-0003).

Methodology

In principle, the determination of lost revenues is a simple calculation:

LR = (CDM savings – CDM savings in the load forecast) * rate

In practice, it is somewhat more complicated than that because of the limitations of the information available to calculate CDM savings, the different time periods of savings data and the rate year, and the need to determine carrying charges on the lost revenues.

CDM savings

In 2011 and 2012, Haldimand County Hydro offered provincial programs that were offered in partnership with the Ontario Power Authority (OPA). Haldimand County Hydro did not offer custom programs beyond the OPA programs.

OPA evaluation results

The OPA performs evaluations of all of its programs, which examine gross energy savings from the programs, and the net-to-gross ratio (NTGR), and then from those calculates net energy savings by initiative within program group (residential, business, industrial and low-income). Peak load reductions are also calculated, and reported in the same way.

Provincial results are allocated to individual LDCs based on their individual performance where possible, or through an allocation process.

The OPA reports energy savings and peak demand reductions, by initiative in the current year, adjustments to the previous year, based on updated validation, and contribution to total savings or reductions to the end of the 2011 to 2014 period. The savings and demand reductions for a particular year for a number of programs persist in the following years up to and including 2014. The savings and demand reductions for demand response programs do not persist beyond the year in which those particular savings and demand reductions occur.

For some programs, savings or demand reductions in a particular year persist into subsequent years, but do not persist fully through 2014. In these cases, the OPA was requested to provide estimates by year of the persistence of savings or reductions in each year.

These are the best, most definitive and defensible estimates of savings associated with these programs, and incorporate the most appropriate estimates of savings from the measures installed.

However, these data have some limitations, and require some adjustments for use in lost revenue calculations.

Allocating savings to rate classes

The OPA reports results by 'program', within four main programs: residential, business, industrial and low-income. These only partially map onto rate classes. For initiatives that apply to more than one rate class, Haldimand County Hydro staff estimated the split by rate class, drawing on participant-specific information where available.

Adjustments for savings that do not affect revenues

As previously mentioned, the OPA reports both energy savings and reductions in [system] peak demand. Depending on the rate class, distribution revenue is based on either kilowatt-hours used, or the customer's monthly peak kilowatt use. For rate classes where the customer is charged for distribution by energy use (kWh), the OPA-reported energy savings are directly relevant.

For customer classes where the LDC charges for distribution based on the customer's peak monthly demand (kW in the month), the system peak reductions are only partially relevant. For initiatives like lighting upgrades in businesses operating during normal business hours, the peak demand reductions are likely to be maintained throughout the year, including during the customer's monthly peaks, and so may be used to estimate lost revenue. For other programs, in particular demand response programs, the customer's monthly peak may not correspond to the system's peak. Further, even if they are coincident, if a demand response event is called, and the customer's monthly peak is shaved, it is likely that the customer's second highest peak in the month is only slightly less than their highest peak. Thus, the impact on distribution revenues of the demand response program is likely to be minimal, and is assumed to have zero impact on lost load.

Thus, no distribution revenues are estimated to be lost from large general service customers' participation in demand response programs.

Load reductions accounted for in the load forecast

In recent years, LDCs have tried to account for load losses due to CDM programs in their load forecasts, submitted as part of their Cost of Service applications. These forecasted reductions need to be deducted from load losses attributable to CDM programs, to determine the final impact of CDM on revenues. That is, the impact is the *variance* between the savings accounted for in the load forecast and the savings attributable to the programs.

Overall impact of CDM on load, by rate class

The overall impact of CDM energy savings and demand reductions on load is calculated from the OPA energy savings and peak demand reductions, allocated by rate class, and adjusted for differences between system peak reductions and customer monthly peak reduction. Finally the difference is calculated between the overall estimated

impact on loads and the load reductions attributable to CDM that were captured in the most recent load forecast.

Distribution rates

Lost revenues for the LDC associated with CDM arise from reductions in the volumetric distribution rate. Most other rate components (e.g. service charges, global adjustment, transmission charges) are either fixed charges, or are just pass-throughs for the utility, so do not affect the LDC's revenues. An exception is for certain rate riders related to taxes, and these are added to the volumetric distribution charges, where applicable.

For most electricity distribution utilities in Ontario, including Haldimand County Hydro, distribution rates are set for the period from 1 May to 30 April of the next year. CDM results are reported for the calendar year, so average rates for the calendar year need to be calculated. For simplicity, the average rate is estimated based on the rate being four twelfths of the previous year's rate (for January through April), and eight twelfths of the current year's rate (for May through December).

Lost revenues

Lost revenues in a particular rate class are the product of the savings or demand reductions in that class, less what was accounted for in the load forecast, multiplied by the average rate for that class in the calendar year for which the energy savings or demand reductions were reported.[2]

These lost revenues are reported by the LDC in their financial statements in Account 1568, and the associated rate class-specific sub-accounts.

Carrying charges

Because these revenues are lost throughout the year, and are only recovered through rate riders in subsequent years, the Ontario Energy Board has permitted the LDCs to claim carrying charges on these lost revenues at a rate prescribed by the OEB, and published on the Board's website. The carrying charges are simple interest, not compounded and are calculated on the monthly lost revenue balance. Because OPA final savings estimated are reported annually, and monthly estimates are not available, the incremental savings are assumed to be equally distributed across the months. So 1/12 of the annual savings are allocated to January, and 12/12 of the annual savings to December.

Carrying charges accrue from the time of the savings, until disposition.

---

[2] Where distribution rates are monthly rates for the peak kW in that month, the annual loss of revenue is the monthly rate times the number of months it applies to – usually twelve.

Results

Following the methodology described above, lost revenues were calculated for Haldimand County Hydro.

CDM savings

OPA evaluation results

CDM savings reported by the OPA are in Appendix A. The Appendix consists of the following tables:

- The verified final 2011 and 2012 results for Haldimand County Hydro are shown in Table 1
- The adjustments to verified final 2011 results for Haldimand County Hydro are shown in Table 2[3]

The gross savings were not provided by the OPA in the 2012 final verified results. For the purposes of estimating lost revenues, only net savings are relevant.

Table A-1 in Appendix A shows the estimated persistence of 2011 savings into future years. Table A-2 in Appendix A shows the estimated persistence of 2012 savings into future years. Table A-3 in Appendix A shows the estimated persistence of 2011 adjustments into future years. For programs that have persistence into future years and persistence is not equal to the savings or adjustments in the first year, the savings or adjustments are assumed to persist until the end of 2013. Any drop in persistence that is indicated by the cumulative totals provided by the OPA is assumed to occur in 2014. Actual persistence numbers for these programs have been requested from the OPA, but have not been received as yet.

Allocating savings to rate classes

Haldimand County Hydro provided information on the allocation of savings to rate classes. In most cases, the allocation is straightforward. Initiatives that can span multiple rate classes include Retrofit, Building Commissioning, New Construction, Energy Audit, Demand Response 3, Process & Systems Upgrades, Monitoring & Targeting, Energy Manager, Electricity Retrofit Incentive Program and High Performance New Construction. No allocation was provided for programs for which Haldimand County Hydro has no program savings.

[3] *Haldimand County Hydro Inc. OPA Annual CDM Report 2012 - Final Verified Results*. Ontario Power Authority. August 30, 2013.

Haldimand County Hydro bills customers in different rate classes using different volumetric units, either kilowatt hours, or customer peak monthly kilowatts. The rate classes and billing unit for Haldimand County Hydro are:

- Residential (kWh)
- GS <50 kW (kWh)
- GS 50 to 4999 kW (kW)
- Unmetered Scattered Load (kWh)
- Sentinel Lighting (kW)
- Street Lighting (kW)
- Microfit generator (kW)
- Embedded distributor (kW)

Table B-1 in Appendix B shows the percentage allocation by rate class for initiatives in 2011. Table B-2 in Appendix B shows the percentage allocation by rate class for initiatives in 2012.

Adjustments for savings that do not affect revenues

The only adjustments relate to rate classes that are billed by customer peak kilowatt in the month. The only initiative that is affected is the Demand Response 3 program, for which no lost revenues are attributed to the reported demand reductions.

Load reductions accounted for in the load forecast

Haldimand County Hydro's last cost of service application was filed in 2010. The load forecast associated with that application did not account for load losses from 2011 – 2014 CDM programs.

Overall impact of CDM on load, by rate class

Multiplying the energy savings or demand reduction reported for Haldimand County Hydro for each program by the allocation by rate class provides the impact on load of that CDM program within the appropriate rate class. The sum of the energy savings and demand reductions for all of the programs for each rate class, with adjustments for savings that do not affect revenue provides the overall impact of CDM on load by rate class.

Table B-3 in Appendix B shows the overall impact of CDM on load, by rate class for 2011.

Table B-4 in Appendix B shows the overall impact of CDM on load, by rate class for 2012.

Distribution rates

The distribution rates that impact lost revenue for each rate class for Haldimand County Hydro are shown in Table C-1 in Appendix C. The

distribution rates for the period from 1 May of each year to 30 April of the next year are pro-rated by number of months to each calendar year in the 2011 to 2014 time period.

Lost revenues

The lost revenues for each year by rate class for Haldimand County Hydro calculated from final CDM program results are shown in Table C-2 in Appendix C. The lost revenue for 2011 is based on the CDM program savings and the adjustments to the 2011 results allocated by rate class and multiplied by the 2011 rate for that rate class. The lost revenue for 2012 is based on the 2012 CDM program savings and persistence of the 2011 program savings in 2012 allocated by rate class and multiplied by the 2012 rate for that rate class.

The lost revenue for 2011 and 2012 are based on final verified results provided by the OPA.

Carrying charges

The monthly carrying charges by rate class on Haldimand County Hydro's lost revenue are shown in Table C-3 in Appendix C. The carrying charges are reported monthly, from the time the lost revenues resulted, through to December 31, 2012.

Conclusions

The LRAMVA balance at the end of December 2012 for Haldimand County Hydro that includes results from 2011 and 2012 CDM programs is $82,208.17. The total carrying charges on this LRAMVA balance accumulated to December 31, 2012 are $1,013.56. These balances are attributable to individual rate classes according to the following table:

Rate class	LRAMVA	Carrying charges	Total
Residential	$39,804.54	$500.86	$40,305.40
GS < 50 kW	$24,415.84	$284.86	$24,700.70
GS 50 to 4999 kW	$17,987.79	$227.85	$18,215.64
Total	**$82,208.17**	**$1,013.56**	**$83,221.74**

NOTE: There is no LRAMVA or carrying charge associated with rate classes not included in this table.

Appendix A. CDM savings reported by the OPA

Table 1: **Haldimand County Hydro Inc.** Initiative and Program Level Savings by Year (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
														2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	270	154			16	9			115,815	61,427			25	647,542
Appliance Exchange	Appliances	22	36			2	5			2,618	9,228			6	36,839
HVAC Incentives	Equipment	375	251			103	57			186,931	98,468			161	1,043,128
Conservation Instant Coupon Booklet	Items	2,155	131			5	1			81,297	5,934			6	342,992
Bi-Annual Retailer Event	Items	3,694	4,503			7	6			124,723	113,664			13	839,883
Retailer Co-op	Items	0	0			0	0			0	0			0	0
Residential Demand Response (switch/pstat)	Devices	19	19			11	9			0	55			0	55
Residential Demand Response (IHD)	Devices	0	0			0				0					
Residential New Construction	Homes	0	1			0	0			0	415			0	1,245
Consumer Program Total						**144**	**87**			**511,385**	**289,191**			**211**	**2,911,684**
Business Program															
Retrofit	Projects	4	20			70	109			435,855	503,091			179	3,252,692
Direct Install Lighting	Projects	44	50			61	40			156,830	149,154			87	1,034,324
Building Commissioning	Buildings	0	0			0	0			0	0			0	0
New Construction	Buildings	1	2			15	11			67,631	36,709			26	380,650
Energy Audit	Audits	0	0			0	0			0	0			0	0
Small Commercial Demand Response	Devices	0	0			0	0			0	0			0	0
Small Commercial Demand Response (IHD)	Devices	0	0			0				0				0	0
Demand Response 3	Facilities	0	0			0	0			0	0			0	0
Business Program Total						**147**	**160**			**660,315**	**688,954**			**292**	**4,667,667**
Industrial Program															
Process & System Upgrades	Projects	0	0			0	0			0	0			0	0
Monitoring & Targeting	Projects	0	0			0	0			0	0			0	0
Energy Manager	Projects	0	0			0	0			0	0			0	0
Retrofit	Projects	0				0				0				0	0
Demand Response 3	Facilities	1	2			21	129			1,237	3,114			0	4,351
Industrial Program Total						**21**	**129**			**1,237**	**3,114**			**0**	**4,351**
Home Assistance Program															
Home Assistance Program	Homes	0	33			0	3			0	30,560			3	91,679
Home Assistance Program Total						**0**	**3**			**0**	**30,560**			**3**	**91,679**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	3	0			4	0			24,629	0			4	98,518
High Performance New Construction	Projects	2	0			71	0			366,177	465			72	1,466,100
Toronto Comprehensive	Projects	0	0			0	0			0	0			0	0
Multifamily Energy Efficiency Rebates	Projects	0	0			0	0			0	0			0	0
LDC Custom Programs	Projects	0	0			0	0			0	0			0	0
Pre-2011 Programs completed in 2011 Total						**76**	**0**			**390,806**	**465**			**76**	**1,564,618**
Other															
Program Enabled Savings	Projects	0	0			0	0			0	0			0	0
Time-of-Use Savings	Homes														
Other Total							**0**				**0**			**0**	**0**
Adjustments to Previous Year's Verified Results							**-12**				**-5,042**			**-12**	**-20,168**
Energy Efficiency Total						**356**	**242**			**1,562,506**	**1,009,115**			**582**	**9,235,592**
Demand Response Total (Scenario 1)						**32**	**138**			**1,237**	**3,169**			**0**	**4,406**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**387**	**368**			**1,563,743**	**1,007,242**			**570**	**9,219,830**
													Full OEB Target:	**2,850**	**13,300,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**20.0%**	**69.3%**

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

Due to the limited timeframe of data, which didn't include the summer months, 2012 IHD results have been deemed inconclusive. The IHD line item on the 2012 annual report will be left blank. Once a full year of data is available (2013 evaluation), and the savings are quantified, 2012 results will be updated to reflect the quantified savings.

Table 2: Adjustments to **Haldimand County Hydro Inc.** Verified Results due to Errors or Omissions (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program															
Appliance Retirement	Appliances	0				0				0				0	0
Appliance Exchange	Appliances	0				0				0				0	0
HVAC Incentives	Equipment	-52				-14				-25,122				-14	-100,489
Conservation Instant Coupon Booklet	Items	35				0				1,170				0	4,680
Bi-Annual Retailer Event	Items	347				0				9,266				0	37,066
Retailer Co-op	Items	0				0				0				0	0
Residential Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Residential Demand Response (IHD)	Devices	0				0				0				0	0
Residential New Construction	Homes	0				0				0				0	0
Consumer Program Total						**-14**				**-14,686**				**-14**	**-58,744**
Business Program															
Retrofit	Projects	2				6				31,596				6	126,384
Direct Install Lighting	Projects	0				0				0				0	0
Building Commissioning	Buildings	0				0				0				0	0
New Construction	Buildings	2				-4				-21,210				-4	-84,839
Energy Audit	Audits	0				0				0				0	0
Small Commercial Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Small Commercial Demand Response (IHD)	Devices	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Business Program Total						**2**				**10,386**				**2**	**41,545**
Industrial Program															
Process & System Upgrades	Projects	0				0				0				0	0
Monitoring & Targeting	Projects	0				0				0				0	0
Energy Manager	Projects	0				0				0				0	0
Retrofit	Projects	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Industrial Program Total						**0**				**0**				**0**	**0**
Home Assistance Program															
Home Assistance Program	Homes	0				0				0				0	0
Home Assistance Program Total						**0**				**0**				**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	0				0				0				0	0
High Performance New Construction	Projects	0				0				-742				0	-2,970
Toronto Comprehensive	Projects	0				0				0				0	0
Multifamily Energy Efficiency Rebates	Projects	0				0				0				0	0
LDC Custom Programs	Projects	0				0				0				0	0
Pre-2011 Programs completed in 2011 Total						**0**				**-742**				**0**	**-2,970**
Other															
Program Enabled Savings	Projects	0				0				0				0	0
Time-of-Use Savings	Homes														
Other Total						**0**				**0**				**0**	**0**
Adjustments to Previous Year's Verified Results						**-12**				**-5,042**				**-12**	**-20,168**

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

Table A-1: Estimated persistence of 2011 savings into future years

		Persistence of 2011 savings					
		2012		2013		2014	
#	Initiative	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)
Consumer Program							
1	Appliance	16	115,815	16	115,815	16	115,814
2	Appliance Exchange	2	2,618	2	2,618	1	1,301
3	HVAC Incentives	103	186,931	103	186,931	103	186,931
4	Conservation Instant Coupon Booklet	5	81,297	5	81,297	5	81,297
5	Bi-Annual Retailer Event	7	124,723	7	124,723	7	124,723
6	Retailer Co-Op						
7	Residential Demand Response						
8	Residential Demand Response (IHD)						
9	Residential New Construction						
Business Program							
10	Retrofit	70	435,855	70	435,855	70	435,855
11	Direct Install Lighting	61	156,830	61	156,830	47	116,372
12	Building Commissioning						
13	New Construction	15	67,631	15	67,631	15	67,631
14	Energy Audit						
15	Small Commercial Demand Response (switch/pstat)						
16	Small Commercial Demand Response (IHD)						
17	Demand Response 3						
Industrial Program							
18	Process & System Upgrades						
19	Monitoring & Targeting						
20	Energy Manager						
21	Retrofit						
22	Demand Response 3						
Home Assistance Program							
23	Home Assistance Program						
Pre-2011 Programs completed in 2011							
24	Electricity Retrofit Incentive Program	4	24,629	4	24,629	4	24,629
25	High Performance New Construction	71	366,177	71	366,177	71	366,177

Note: Persistence is based on net incremental and program-to-date contributions to 2014 targets reported by the OPA. Some program results do not persist into future years and others persist equally into future years. For programs that have persistence into future years and persistence is not equal to the saving in the first year, the savings are assumed to persist until the end of 2013 and any drop in persistence is assumed to occur in 2014.

Table A-2: Estimated persistence of 2012 savings into future years

		Persistence of 2012 savings			
		2013		2014	
#	Initiative	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)
Consumer Program					
1	Appliance Replacement	9	61,427	9	61,428
2	Appliance Exchange	5	9,228	5	9,227
3	HVAC Incentives	57	98,468	57	98,468
4	Conservation Instant Coupon Booklet	1	5,934	1	5,934
5	Bi-Annual Retailer Event	6	113,664	6	113,664
6	Retailer Co-Op				
7	Residential Demand Response (switch/pstat)				
8	Residential Demand Response (IHD)				
9	Residential New Construction		415		415
Business Program					
10	Retrofit	109	503,091	109	503,092
11	Direct Install Lighting	40	149,154	40	149,154
12	Building Commissioning				
13	New Construction	11	36,709	11	36,709
14	Energy Audit				
15	Small Commercial Demand Response (switch/pstat)				
16	Small Commercial Demand Response (IHD)				
17	Demand Response 3				
Industrial Program					
18	Process & System Upgrades				
19	Monitoring & Targeting				
20	Energy Manager				
21	Retrofit				
22	Demand Response 3				
Home Assistance Program					
23	Home Assistance Program	3	30,560	3	30,560
Pre-2011 Programs completed in 2011					
24	Electricity Retrofit Incentive Program				
25	High Performance New Construction		465		465

Note: Persistence is based on net incremental and program-to-date contributions to 2014 targets reported by the OPA. Some program results do not persist into future years and others persist equally into future years. For programs that have persistence into future years and persistence is not equal to the saving in the first year, the savings are assumed to persist until the end of 2013 and any drop in persistence is assumed to occur in 2014.

Table A-3: Estimated persistence of 2011 adjustments into future years

		Persistence of 2011 adjustments					
		2012		2013		2014	
#	Initiative	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)
Consumer Program							
1	Appliance						
2	Appliance Exchange						
3	HVAC Incentives	-14	-25,122	-14	-25,122	-14	-25,122
4	Conservation Instant Coupon Booklet		1,170		1,170		1,170
5	Bi-Annual Retailer Event		9,266		9,266		9,266
6	Retailer Co-Op						
7	Residential Demand Response						
8	Residential Demand Response (IHD)						
9	Residential New Construction						
Business Program							
10	Retrofit	6	31,596	6	31,596	6	31,596
11	Direct Install Lighting						
12	Building Commissioning						
13	New Construction	-4	-21,210	-4	-21,210	-4	-21,210
14	Energy Audit						
15	Small Commercial Demand Response (switch/pstat)						
16	Small Commercial Demand Response (IHD)						
17	Demand Response 3						
Industrial Program							
18	Process & System Upgrades						
19	Monitoring & Targeting						
20	Energy Manager						
21	Retrofit						
22	Demand Response 3						
Home Assistance Program							
23	Home Assistance Program						
Pre-2011 Programs completed in 2011							
24	Electricity Retrofit Incentive Program						
25	High Performance New Construction		-742		-742		-742

Note: Persistence is based on net incremental and program-to-date contributions to 2014 targets reported by the OPA. Some program results do not persist into future years and others persist equally into future years. For programs that have persistence into future years and persistence is not equal to the adjusments in the first year, the adjustments are assumed to persist until the end of 2013 and any drop in persistence is assumed to occur in 2014.

Appendix B. CDM savings breakdown by rate class

Table B-1: Percentage allocation by rate class for initiatives in 2011

#	Initiative	Residential	GS < 50 kW	GS 50 to 4999 kW	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Microfit generator	Embedded distributor
Consumer Program									
1	Appliance Retirement	100%							
2	Appliance Exchange	100%							
3	HVAC Incentives	100%							
4	Conservation Instant Coupon Booklet	100%							
5	Bi-Annual Retailer Event	100%							
6	Retailer Co-op	100%							
7	Residential Demand Response	100%							
8	Residential New Construction	100%							
Business Program									
9	Efficiency: Equipment Replacement		50%	50%					
10	Direct Install Lighting		100%						
11	Existing Building Commissioning Incentive								
12	New Construction and Major Renovation Incentive			100%					
13	Energy Audit								
14	Commercial Demand Response (part of the Residential program schedule)		100%						
15	Demand Response 3 (part of the Industrial program schedule)								
Industrial Program									
16	Process & System Upgrades								
17	Monitoring & Targeting								
18	Energy Manager								
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)		50%	50%					
20	Demand Response 3			100%					
Home Assistance Program									
21	Home Assistance Program	100%							
Pre-2011 Programs completed in 2011									
22	Electricity Retrofit Incentive Program		60%	40%					
23	High Performance New Construction			100%					

Source: Haldimand County Hydro

Table B-2: Percentage allocation by rate class for initiatives in 2012

#	Initiative	Residential	GS < 50 kW	GS 50 to 4999 kW	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Microfit generator	Embedded distributor
Consumer Program									
1	Appliance Replacement	100%							
2	Appliance Exchange	100%							
3	HVAC Incentives	100%							
4	Conservation Instant Coupon Booklet	100%							
5	Bi-Annual Retailer Event	100%							
6	Retailer Co-Op	100%							
7	Residential Demand Response (switch/pstat)	100%							
8	Residential Demand Response (IHD)	100%							
9	Residential New Construction	100%							
Business Program									
10	Retrofit		50%	50%					
11	Direct Install Lighting		100%						
12	Building Commissioning								
13	New Construction			100%					
14	Energy Audit								
15	Small Commercial Demand Response (switch/pstat)		100%						
16	Small Commercial Demand Response (IHD)		100%						
17	Demand Response 3								
Industrial Program									
18	Process & System Upgrades								
19	Monitoring & Targeting								
20	Energy Manager								
21	Retrofit		50%	50%					
22	Demand Response 3			100%					
Home Assistance Program									
23	Home Assistance Program	100%							
Pre-2011 Programs completed in 2011									
24	Electricity Retrofit Incentive Program								
25	High Performance New Construction			100%					
26	Toronto Comprehensive								
27	Multifamily Energy Efficiency Rebates								
28	LDC Custom Programs								

Source: Haldimand County Hydro

Table B-3: Impact of CDM on load, by rate class for 2011

#	Initiative	Residential	GS < 50 kW	GS 50 to 4999 kW	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Microfit generator	Embedded distributor
	Units	**kWh**	**kWh**	**kW**	**kWh**	**kW**	**kW**	**kW**	**kW**
Consumer Program									
1	Appliance Retirement	115,815							
2	Appliance Exchange	2,618							
3	HVAC Incentives	161,809							
4	Conservation Instant Coupon Booklet	82,467							
5	Bi-Annual Retailer Event	133,989							
6	Retailer Co-op								
7	Residential Demand Response								
8	Residential New Construction								
Business Program									
9	Efficiency: Equipment Replacement		233,725	458					
10	Direct Install Lighting		156,830						
11	Existing Building Commissioning Incentive								
12	New Construction and Major Renovation Incentive			133					
13	Energy Audit								
14	Commercial Demand Response (part of the Residential program schedule)								
15	Demand Response 3 (part of the Industrial program schedule)								
Industrial Program									
16	Process & System Upgrades								
17	Monitoring & Targeting								
18	Energy Manager								
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)								
20	Demand Response 3			253					
Home Assistance Program									
21	Home Assistance Program								
Pre-2011 Programs completed in 2011									
22	Electricity Retrofit Incentive Program		14,778	20					
23	High Performance New Construction			856					
	Total	**496,699**	**405,333**	**1,467**					

Note: impact on load is calculated from net incremental peak demand or net incremental savings on Table 1 from the OPA (Appendix A), depending on how that rate class is billed for distribution service, and the allocation of savings by rate class in Table B-1. Where billing is by monthly demand (kW), the annual demand is multiplied by 12.

Table B-4: Impact of CDM on load, by rate class for 2012

#	Initiative	Residential	GS < 50 kW	GS 50 to 4999 kW	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Microfit generator	Embedded distributor
	Units	**kWh**	**kWh**	**kW**	**kWh**	**kW**	**kW**	**kW**	**kW**
Consumer Program									
1	Appliance Replacement	61,427							
2	Appliance Exchange	9,228							
3	HVAC Incentives	98,468							
4	Conservation Instant Coupon Booklet	5,934							
5	Bi-Annual Retailer Event	113,664							
6	Retailer Co-Op								
7	Residential Demand Response (switch/pstat)	55							
8	Residential Demand Response (IHD)								
9	Residential New Construction	415							
Business Program									
10	Retrofit		251,546	654					
11	Direct Install Lighting		149,154						
12	Building Commissioning								
13	New Construction			132					
14	Energy Audit								
15	Small Commercial Demand Response (switch/pstat)								
16	Small Commercial Demand Response (IHD)								
17	Demand Response 3								
Industrial Program									
18	Process & System Upgrades								
19	Monitoring & Targeting								
20	Energy Manager								
21	Retrofit								
22	Demand Response 3			1,548					
Home Assistance Program									
23	Home Assistance Program	30,560							
Pre-2011 Programs completed in 2011									
24	Electricity Retrofit Incentive Program								
25	High Performance New Construction								
26	Toronto Comprehensive								
27	Multifamily Energy Efficiency Rebates								
28	LDC Custom Programs								
	Total	**319,751**	**400,700**	**786**					

Note: impact on load is calculated from net incremental peak demand or net incremental savings on Table 1 from the OPA (Appendix A), depending on how that rate class is billed for distribution service, and the allocation of savings by rate class in Table B-2. Where billing is by monthly demand (kW), the annual demand is multiplied by 12.

Appendix C. Lost revenue

Table C-1: Distribution rates that impact lost revenue for each rate class

Rate class	Billing unit	2011	2012	2013	2014
Residential	kWh	0.0319	0.0294	0.0270	0.0262
GS < 50 kW	kWh	0.0202	0.0201	0.0202	0.0203
GS 50 to 4999 kW	kW	4.9462	4.7639	4.7890	4.8015
Unmetered Scattered Load	kWh	0.0027	0.0024	0.0024	0.0025
Sentinel Lighting	kW	28.3637	32.7018	32.8166	32.9681
Street Lighting	kW	13.5168	15.2213	15.2779	15.3448
Microfit generator	kW				
Embedded distributor	kW	0.5601	0.5637	0.5671	0.5680

Notes: Distribution rates are from OEB approved rate schedules averaged from the rate year to the calendar year. Only the Distribution Volumetric Rate and the Rate Rider for Application of Tax Change are used.

Table C-2: Lost revenues for each year by rate class

Description	Residential	GS < 50 kW	GS 50 to 4999 kW	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Microfit generator	Embedded distributor	Total
2011 actuals	$15,828.13	$8,187.72	$7,255.33						$31,271.18
2012 actuals	$23,976.41	$16,228.12	$10,732.47						$50,936.99
Balance	**$39,804.54**	**$24,415.84**	**$17,987.79**						**$82,208.17**

Note: Values are the product of the lost loads (Tables B-3 and B-4), and the rates (Table C-1) for each rate class.

Table C-3: Monthly carrying charges by rate class

Month	Residential	GS < 50 kW	GS 50 to 4999 kW	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Microfit generator	Embedded distributor	Total
Jan-11									
Feb-11	$1.62	$0.84	$0.74						$3.19
Mar-11	$3.23	$1.67	$1.48						$6.38
Apr-11	$4.85	$2.51	$2.22						$9.58
Total for Rate year 2010	**$9.69**	**$5.01**	**$4.44**						**$19.15**
May-11	$6.46	$3.34	$2.96						$12.77
Jun-11	$8.08	$4.18	$3.70						$15.96
Jul-11	$9.69	$5.01	$4.44						$19.15
Aug-11	$11.31	$5.85	$5.18						$22.35
Sep-11	$12.93	$6.69	$5.93						$25.54
Oct-11	$14.54	$7.52	$6.67						$28.73
Nov-11	$16.16	$8.36	$7.41						$31.92
Dec-11	$17.77	$9.19	$8.15						$35.11
Jan-12	$19.39	$10.03	$8.89						$38.31
Feb-12	$21.84	$11.69	$9.98						$43.51
Mar-12	$24.28	$13.34	$11.08						$48.71
Apr-12	$26.73	$15.00	$12.17						$53.91
Total for Rate year 2011	**$198.89**	**$105.22**	**$91.01**						**$395.12**
May-12	$29.18	$16.66	$13.27						$59.11
Jun-12	$31.63	$18.31	$14.37						$64.31
Jul-12	$34.08	$19.97	$15.46						$69.51
Aug-12	$36.52	$21.63	$16.56						$74.71
Sep-12	$38.97	$23.28	$17.65						$79.91
Oct-12	$41.42	$24.94	$18.75						$85.11
Nov-12	$43.87	$26.60	$19.84						$90.31
Dec-12	$46.31	$28.25	$20.94						$95.51
Total to December 31, 2012	**$500.86**	**$284.86**	**$227.85**						**$1,013.56**

Note: Carrying charges are simple interest (not compound) calculated using rates specified by the OEB at:
http://www.ontarioenergyboard.ca/OEB/Industry/Rules+and+Requirements/Rules+Codes+Guidelines+and+Forms/Prescribed+Interest+Rates
Annual savings are assumed to be distributed equally over the year and carrying charges are applied to the balance in the account each month.

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