2.12 EXHIBIT 9: DEFERRAL AND VARIANCE ACCOUNTS

INDEX

Exhibit 9 Filing Requirements: Cross Reference List

OEB Chapter 2 Filing Requirements- Heading/Sub-heading		Guelph Hydro Application Heading/Sub-heading	
2.12	**Exhibit 9: Deferral and Variance Accounts**	**2.12**	**Exhibit 9: Deferral and Variance Accounts**
2.12.1	PILs and Tax Variances for 2006 and Subsequent Years - Account 1592	2.12.1	PILs and Tax Variances for 2006 and Subsequent Years - Account 1592
2.12.2	Harmonized Sales Tax Deferral Account	2.12.2	Harmonized Sales Tax Deferral Account
2.12.3	One-time Incremental IFRS Costs	2.12.3	One-time Incremental IFRS Costs
2.12.4	Account 1575, IFRS-CGAAP Transitional PP&E Amounts	2.12.4	Account 1575, IFRS-CGAAP Transitional PP&E Amounts
2.12.5	Account 1576, Accounting Changes Under CGAAP	2.12.5	Account 1576, Accounting Changes Under CGAAP
2.12.6	Retail Service Charges	2.12.6	Retail Service Charges
2.12.7	Disposition of Deferral and Variance Accounts	2.12.7	Disposition of Deferral and Variance Accounts

2.12 EXHIBIT 9: DEFERRAL AND VARIANCE ACCOUNTS

Guelph Hydro has included in this Application a request for approval for the disposition of deferral and variance account balances at December 31, 2014 and the forecasted interest through December 31, 2015 for the deferral and Regulatory Settlement Variance Accounts (RSVAs) listed below. The total amount of the variance requested for disposition, including the interest, is $2,919,074.

Guelph Hydro proposes a 1-year disposition period.

Guelph Hydro has not used any account differently than as described in the APH.

List of all outstanding deferral and variance accounts and sub-accounts:

- 1508 – Other Regulatory Assets – Deferred IFRS Transition Costs
- 1518 – $RCVA_{Retail}$
- 1532 – Renewable Connection OM&A Deferral Account
- 1533 – Renewable Generation Connection Funding Adder Deferral Account
- 1548 – $RCVA_{STR}$
- 1550 – Low Voltage Variance Account
- 1551 – Smart Metering Entity Charge Variance
- 1555 - Smart Meter Capital and Recovery Offset Variance – Sub-account Zigbee Chip Initiative – requested to be included in the 2016 rate base
- 1556 - Smart Meter OM&A Variance – depreciation Zigbee Chip
- 1580 – Retail Settlement Variance Account - Wholesale Market Service Charges
- 1584 – Retail Transmission Network Charges
- 1586 – Retail Transmission Connection Charges

- 1588 – Retail Settlement Variance Account – Power
- 1589 – Retail Settlement Variance Account - Global Adjustment
- 1592 - PILs and Tax Variance
- 1595 – Sub-account Disposition of Account Balances Approved in 2010 IRM
- 1595- Sub-account Disposition of Account Balances Approved in 2012 COS
- 1568 – LRAM Variance Account – detailed in Exhibit 4, Tab 6, Schedule 3, 2.7.6.3 LRAM Variance Account (LRAMVA).

Continuity Schedule:

The Continuity Schedule covers the period from January 1, 2010 to December 31, 2014. The 2014 end principal and interest dispositions in 2015 as instructed by the Board and calculated carrying charges to the end of the 2015 bridge year is presented in this Exhibit, Appendix 9-A: DVA Continuity Schedule for COS Applications. A completed version of the Continuity Schedule has been submitted in working Microsoft Excel format. Guelph Hydro has used the 2015 DVA Continuity Schedule available on the OEB's web site. The Board's staff made an unlocked version available to Guelph Hydro in order to adapt the model for this 2016 Cost of Service application. Guelph Hydro has developed an additional model in the Board's EDDVAR Continuity Schedule model (Tab 8. Guelph RSVA Model) to calculate the Rate Riders for RSVAs balances disposition for Wholesale Market Participants ("WMPs") and Class A customers (please see this Exhibit, Tab 7, 2.12.7 Disposition of Deferral and Variance Accounts for further details).

Interest rates applied to calculate the carrying charges:

The interest rates applied to calculate the carrying charges for all regulatory deferral and variance accounts are the OEB's prescribed interest rates (i.e. 1.47% from January 2012 to December 2014).

Actual interest has been calculated based on the Board's prescribed rates. Forecasted interest for the period January 1, 2015 to December 31, 2015 is based upon a weighted average of the 2015 Board prescribed rates, by applying the Q1 2015 Board Approved rate of 1.47% for three months and the Q2 2015 Board Approved 1.10% for 9 months, divided by 12 to achieve a weighted average interest rate of 1.1925% ((3 x 1.47%) + (9 x 1.10%)/12).

Table 9-1 presents the historical Board prescribed interest rates from 2012 to 2015.

Table 9-1

Quarter by Year	Approved Deferral and Variance Accounts Prescribed Interest Rate (per the Bankers' Acceptances-3 months Plus 0.25 Spread)
Q4 2015 Forecast	1.10
Q3 2015 Forecast	1.10
Q2 2015	1.10
Q1 2015	1.47
Q4 2014	1.47
Q3 2014	1.47
Q2 2014	1.47
Q1 2014	1.47
Q4 2013	1.47
Q3 2013	1.47
Q2 2013	1.47
Q1 2013	1.47
Q4 2012	1.47
Q3 2012	1.47
Q2 2012	1.47
Q1 2012	1.47

Account Balances

The account balances in the Continuity Schedule do not differ from the account balances in the trial balance reported through the *Electricity Reporting and Record-keeping Requirements*. The account balances in the Continuity Schedule are not recognized in Guelph Hydro's audited financial statements since they are prepared in accordance with International Financial Reporting Standards (IFRS), which upon adoption of IFRS effective January 1, 2010 did not permit the recognition of regulatory deferral balances in the financial statements.

Identification of Group 2 accounts Guelph Hydro will continue and discontinue

Table 9-2 below lists all Group 2 accounts which Guelph Hydro will continue and discontinue on a going-forward basis. Guelph Hydro has only included those Group 2 accounts that have balances as of the 2015 Bridge Year.

Table 9-2 – Group 2 Accounts – Continue & Discontinue

Account Description	USoA #	Continue/ Discontinue	Explanation
Group 2 Accounts - Continue:			
Retail Cost Variance Account - Retail	1518	continue	on-going use
Retail Cost Variance Account - STR	1548	continue	on-going use
LRAM Variance Account	1568	continue	Guelph Hydro will use it to track 2015 to 2020 CDM programs savings
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	continue	on-going use
Group 2 Accounts - Discontinue:			
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	discontinue	asked for disposition in 2016 COS proceedings
Renewable Generation Connection Capital Deferral Account	1531	discontinue	asked for disposition in 2016 COS proceedings
Renewable Generation Connection OM&A Deferral Account	1532	discontinue	asked for disposition in 2016 COS proceedings
Renewable Generation Connection Funding Adder Deferral Account	1533	discontinue	asked for disposition in 2016 COS proceedings
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	discontinue	asked for disposition in 2016 COS proceedings
Smart Meter OM&A Variance	1556	discontinue	asked for disposition in 2016 COS proceedings

1518 RCVA - Retail

This account is used to record the net of:

i. Revenues derived, from the following services:

a) Establishing Service Agreements;

b) Distributor-Consolidated Billing; and

c) Retailer-Consolidated Billing

AND

ii. The costs of entering into Service Agreements, and related contract administration, monitoring, and other expenses necessary to maintain the contract, as well as the incremental costs incurred to provide the services in (b), and (c) above, as applicable, and the avoided costs credit arising from Retailer-Consolidated Billing as applicable.

Carrying charges are applied to this account are calculated using simple interest at the rate prescribed by the Board applied to the monthly opening balances in the account (exclusive of accumulated interest).

1548 RCVA - STR

This account is used monthly to record the net of:

i. Revenues derived from the Service Transaction Request services and charged by Guelph Hydro, as prescribed, in the form of a:

   a) Request fee;

   b) Processing fee;

   c) Information Request fee;

   d) Default fee; and

   e) Other Associated Costs fee;

AND

ii. The incremental cost of labour, internal information system maintenance costs, and delivery costs related to the provision of the services associated with the above items.

Carrying charges are applied to this account are calculated using simple interest at the rate prescribed by the Board applied to the monthly opening balances in the account (exclusive of accumulated interest).

1568 LRAM Variance Account

This account includes the lost revenue adjustment mechanism (“LRAM”) variances in relation to the conservation and demand management (“CDM”) programs or activities undertaken by Guelph Hydro in accordance with Board-prescribed requirements (e.g.

licence, codes and guidelines). The LRAM variance recorded in this account, at the customer rate-class level, is the difference between:

i. The results of the actual verified impacts of authorized CDM activities undertaken by the electricity distributor for Board-approved CDM programs and/or OPA-Contracted Province-Wide CDM programs in relation to activities undertaken by the distributor and/or delivered for the distributor by a third party under contract (in the distributor's franchise area), and

ii. The level of CDM program activities included in the distributor's load forecast (i.e. the level embedded into rates).

The variance recorded is the calculated result of the lost revenues by customer class based on the volumetric impact of the load reductions arising from the CDM measures implemented, multiplied by the distributor's Board-approved variable distribution charges applicable to the customer rate class in which the volumetric variance occurred.

Carrying charges applied to this account are calculated using simple interest at the rate prescribed by the Board, and are applied to the monthly opening balances in the account (exclusive of accumulated interest).

1592 PILs and Tax Variances for 2006 and Subsequent Years, Sub-account HST / OVAT Input Tax Credits (ITCs)

Effective on July 1, 2010, this account includes the incremental ITCs that Guelph Hydro received on distribution revenue requirement items that were previously subject to PST and had since become subject to HST. In its 2012 Cost of Service decision, Guelph Hydro received approval for the disposition of $564,143 (excluding carrying charges) representing the balance of Account 1592 *PILs and Tax Variances for 2006 and Subsequent Years* as at December 31, 2010. This amount included $29,711 representing the company's HST/OVAT ITCs sub-account balance as at December 31, 2010. The tracking of these amounts in this sub-account continued until December 31, 2011, after which point the impact of the HST and associated ITCs on capital and operating costs was reflected in the applied for revenue requirement i.e. for 2012 and subsequent years. The $53,379 payable balance in this account as at December 31, 2014 represents the incremental ITCs received by Guelph Hydro for the period from January 1, 2011 to December 31, 2011 plus associated carrying charges projected to December 31, 2015.

These amounts were not approved for disposal in Guelph Hydro's 2012 Cost of Service decision. The carrying charges applied to this account are calculated using simple interest at the rate prescribed by the Board applied to the monthly opening balances in the account (exclusive of accumulated interest).

Guelph Hydro is seeking disposition of Account 1592 – subaccount PILs and Tax Variances, and has completed Appendix 2-TA below.

Appendix 2-TA
Account 1592, PILs and Tax Variances for 2006 and Subsequent Years

The following table should be completed based on the information requested below, in accordance with the notes following the table. An explanation should be provided for any blank entries.

Tax Item	Principal as of December 31, 2014
Large Corporation Tax grossed-up proxy from 2006 EDR application PILs model for the period from May 1, 2006 to April 30, 2007	-$ 27,810
Large Corporation Tax grossed-up proxy from 2006 EDR application PILs model for the period from January 1, 2006 to April 30, 2006 (4/12ths of the approved grossed-up proxy), if not recorded in PILs account 1562	
Ontario Capital Tax rate decrease and increase in capital deduction for 2007	-$ 66,808
Ontario Capital Tax rate decrease and increase in capital deduction for 2008	-$ 47,797
Ontario Capital Tax rate decrease and increase in capital deduction for 2009	
Ontario Capital Tax rate decrease and increase in capital deduction for 2010	
Ontario Capital Tax rate decrease and increase in capital deduction for 2011	
Ontario Capital Tax rate decrease and increase in capital deduction for 2012	
Ontario Capital Tax rate decrease and increase in capital deduction for 2013	
Capital Cost Allowance class changes from 2006 EDR application for 2006	-$ 3,571
Capital Cost Allowance class changes from 2006 EDR application for 2007	-$ 5,357
Capital Cost Allowance class changes from 2006 EDR application for 2008	-$ 3,571
Capital Cost Allowance class changes from 2006 EDR application for 2009	
Capital Cost Allowance class changes from 2006 EDR application for 2010	
Capital Cost Allowance class changes from 2006 EDR application for 2011	
Capital Cost Allowance class changes from 2006 EDR application for 2012	
Capital Cost Allowance class changes from 2006 EDR application for 2013	
Capital Cost Allowance class changes from any prior application not recorded above. Please provide details and explanation separately.	
Estimate of PILs overprovision as per 2008 Rate Decision	-$ 200,000
Income tax changes from 2006 Rate application for 2008	-$ 179,517
HST/OVAT input tax credits	-$ 80,508
Approved Recovery per 2012 Rate Decision	$ 564,143
LTD Carrying charges	-$ 2,582
Insert description of additional item(s) and new rows if needed.	
Total	-$ 53,379

Notes:

1 Revise the deferral and variance account continuity schedule to include account 1592 as a group 2 account and enter all relevant information for transactions, adjustments, etc., for all relevant years.

2 Describe each type of tax item that has been recorded in account 1592.

3 Provide the calculations that show how each item was determined and provide any pertinent supporting evidence and documentation.

4 Please state whether or not the applicant followed the guidance provided in the FAQ of July 2007. If not, please provide an explanation.

1508 Other Regulatory Assets, sub-account Deferred IFRS Transition

Guelph Hydro uses this account to record one-time administrative incremental IFRS transition costs, which are not already approved and included for recovery in distribution rates. The costs recorded in this account are incremental one-time administrative costs caused by the transition of accounting policies, procedures, systems and processes to IFRS. The incremental costs include professional accounting and legal fees, salaries, wages and benefits of staff added to support the transition to IFRS and associated staff training and development costs. The incremental transition costs do not include ongoing IFRS compliance costs, the financial impacts arising from adopting accounting policy changes that reflect changes in the timing of the recognition of income, or costs related to system upgrades, replacements or changes where IFRS was not the major reason for conversion. In addition, incremental IFRS transition costs do not include capital assets or expenditures.

In its 2012 Cost of Service submission, Guelph Hydro received approval for the recovery of $439,579 representing the Company's Deferred IFRS Transition balance as at December 31, 2010. In 2011, Guelph Hydro incurred additional incremental IFRS transitions costs. The $48,341 receivable balance in this account as at December 31, 2014 represents incremental IFRS transition costs incurred by Guelph Hydro for the period from January 1, 2011 to June 30, 2011 plus associated carrying charges projected to December 31, 2015. These amounts were not approved for disposal in Guelph Hydro's 2012 Cost of Service submission.

The carrying charges applied to this account are calculated using simple interest at the rate prescribed by the Board applied to the monthly opening balances in the account (exclusive of accumulated interest).

Guelph Hydro is seeking disposition of Account 1508 – subaccount Deferred IFRS Transition Costs, and has completed Appendix 2-U below.

One-Time Incremental IFRS Transition Costs

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include one-time incremental IFRS transition costs that are currently included in Account 1508, Other Regulatory Assets, sub-account Deferred IFRS Transition Costs Account, or Account 1508, Other Regulatory Assets, sub-account IFRS Transition Costs Variance Account.

Nature of One-Time Incremental IFRS Transition Costs [1]	Audited Actual Costs Incurred 2011	Audited Actual Costs Incurred 2012	Audited Actual Costs Incurred 2013	Audited Carrying Charges to Dec 31, 2013	Forecasted Costs 2014	Forecasted Costs 2015	Total Costs Excluding Carrying Charges	Carrying Charges January 1, 2014 to April 30, 2015	Total Costs and Carrying Charges	Reasons why the costs recorded meet the criteria of one-time IFRS administrative incremental costs
professional accounting fees	$ 54,050						$ 54,050	-$ 5,709	$ 48,341	Temporary costs incurred to backfill accounting positions seconded to IFRS implementation project
professional legal fees							$ -		$ -	
salaries, wages and benefits of staff added to support the transition to IFRS							$ -		$ -	
associated staff training and development costs							$ -		$ -	
costs related to system upgrades, or replacements or changes where IFRS was the major reason for conversion							$ -		$ -	
							$ -		$ -	
							$ -		$ -	
							$ -		$ -	
							$ -		$ -	
Amounts, if any, included in previous Board approved rates (amounts should be negative) [3]							$ -		$ -	
							$ -		$ -	
Insert description of additional item(s) and new rows if needed.							$ -		$ -	
Total	$ 54,050	$ -	$ -	$ -	$ -	$ -	$ 54,050		$ 48,341	

Note:

1 The Deferred IFRS Transition Costs Account and the IFRS Transition Costs Variance Account are exclusively for necessary, incremental transition costs and shall not include ongoing IFRS compliance costs or impacts arising from adopting accounting policy changes that reflect changes in the timing of the recognition of income. The incremental costs in these accounts shall not include costs related to system upgrades, or replacements or changes where IFRS was not the major reason for conversion. In addition, incremental IFRS costs shall not include capital assets or expenditures.

2 If there were any amounts approved in previous Board approved rates,

1531 Renewable Connection Capital Deferral Account

Investments associated with expansions to connect renewable generation facilities and renewable enabling improvements, both as defined in the Distribution System Code, are recorded in this capital deferral account. In addition, the capital cost of changes to a distributor's Customer Information System to enable the automated settlement of FIT ("Feed-in Tariff") or microFIT contracts may be included in this account.

The carrying charges applied to this account are calculated using simple interest at the rate prescribed by the Board, and are applied to the monthly opening balances in the account (exclusive of accumulated interest).

Guelph Hydro does not have any investments of this type to report and is asking for the discontinuation of this deferral and variance account.

1532 Renewable Connection OM&A Deferral Account

Incremental operating, maintenance, amortization and administrative expenses directly related to expansions to connect renewable generation facilities, and renewable enabling improvements, both as defined in the Distribution System Code, should be recorded in this operating deferral account. In addition, costs that can be recorded in this account include expenses associated with preparing a "GEA Plan" and expenses associated with changes to a distributor's Customer Information System to enable the automated settlement of FIT ("Feed-in Tariff") or microFIT contracts.

Distributors should not record in this account any allocation of general expenses that are not specifically related to the investments that can be recorded in Account 1531.

The carrying charges applied to this account are calculated using simple interest at the rate prescribed by the Board, and are applied to the monthly opening balances in the account (exclusive of accumulated interest).

1533 Renewable Generation Connection Funding Adder Deferral Account

This account records the revenues collected through the GEA funding adder approved by the Board in Guelph Hydro's 2012 Cost of Service proceedings (EB-2011-0123), subject to a prudence review at the time of Guelph Hydro's next Cost of Service application. The GEA funding adder was effective April 1, 2012, with a sunset date of March 31, 2015. Separate sub-accounts are used to record any amounts collected from Guelph Hydro's ratepayers and any amounts received from the Independent Electricity System Operator (pursuant to the provincial pooling mechanism set out in section 79.1 of the Ontario Energy Board Act, 1998) in respect of the projects.

The carrying charges applied to this account are calculated using simple interest at the rate prescribed by the Board, and are applied to the monthly opening balances in the account (exclusive of accumulated interest).

1555 Smart Meter Capital and Recovery Offset Variance Account

Guelph Hydro's procured and deployed smart meters all have an additional communications chip which uses the Zigbee communications technology to allow the smart meter to communicate with Zigbee-enabled devices in the customer's home or business. In its Decision and Rate Order dated February 22, 2012 resulting from Guelph Hydro's 2012 CoS proceedings (EB-2011-0123), the Board would not approve the recovery of the cost of the Zigbee Chips in rates. Instead, the Board directed Guelph Hydro to record the amounts associated with the Zigbee technology in a sub-account of Account 1555, to be called "Sub-account – Zigbee Chip Initiative". The Board stated that if, at a future point in time, Guelph Hydro determined that there was the potential for the Zigbee chip to provide any ratepayer benefit, Guelph had the option of requesting a prudence review to seek the recovery of its Zigbee chip investment on the basis that it acted prudently in making its investment in the Zigbee chip.

The carrying charges applied to this account are calculated using simple interest at the rate prescribed by the Board, and are applied to the monthly opening balances in the account (exclusive of accumulated interest).

1556 Smart Meter OM&A Variance Account

This account is used to record the incremental amortization related to the Zigbee Chip investment recorded in account 1555 Smart Meter Capital and Recovery Offset Variance Account.

The carrying charges applied to this account are calculated using simple interest at the rate prescribed by the Board, and are applied to the monthly opening balances in the account (exclusive of accumulated interest).

New Accounts/Sub-accounts

Guelph Hydro is not requesting any new deferral/variance accounts or sub-accounts.

Adjustments to Deferral and Variance Accounts ("DVA")

In accordance with the Filing Requirements to provide a supporting statement indicating whether any adjustments were made to deferral and variance account balances that were previously approved by the Board on a final basis, Guelph Hydro states that all deferral and variance account balances were only adjusted by the approved amounts for disposition.

Guelph Hydro has presented a summary of the disposition decisions and the sunset dates below:

Table 9-4 Deferral and Variance Accounts approved for Disposition [decisions & sunset dates]

	2012 COS	2012 COS	2014 IRM	2015 IRM
Sunset Date	**March 31, 2013**	**March 31, 2016**	**December 31, 2014**	**December 31, 2015**
Board's Decision	**EB-2011-0123**	**EB-2011-0123**	**EB-2013-0133**	**EB-2014-0077**
Group 1				
WSM	1580		1580	1580
RTNC	1584		1584	1584
RTCC	1586		1586	1586
Power	1588		1588	1588
Power-GA	1588-GA		1589	1589
Low Voltage	1550		1550	1550
Smart Metering Charge Variance				1551
Disposition of Account Balances Approved in 2008 COS	1595-(2008 COS)		1595-(2008 COS remaining)	1595-(2008 COS remaining)
Disposition of Account Balances Approved in 2010 IRM	1595 - (2010 IRM)		1595- (2010 IRM)	1595-(2010 IRM remaining)
Disposition of Account Balances Approved in 2012 COS	1595 - (2012 COS)			1595 - (2012 COS)
Group 2	Other Reg. Assets			
Other Reg. Assets	1508-IFRS			
RCVA-Retail	1518			
RCVA-STR	1548			
Smart Meter Capital	1555-included in the rate base			
Smart Meter OMA	1556-included in the rate base			
Deferred PILs Account		1562		
PILs & Tax Variance	1592			
Special Purpose Charge Assesment Variance Account	1521			

Table 9-5 Deferral and Variance Accounts approved for Disposition [$]

	2012 COS		2014 IRM		2015 IRM	
Sunset Date	**EB-2011-0123**		**EB-2013-0133**		**EB-2014-0077**	
Board's Decision	**Principal**	**Interest**	**Principal**	**Interest**	**Principal**	**Interest**
Group 1	RSVA					
1580-WMS	($1,922,324)	($38,863)	($3,989,563)	($127,785)	($961,981)	$6,615
1584-RTNC	$667,902	$14,641	$1,345,249	$27,626	$517,305	($11,516)
1586-RTCC	($373,043)	($9,060)	$515,947	$4,930	($112,262)	($8,634)
1588-Power	($739,604)	($17,838)	$1,579,299	($159,858)	$861,186	($1,463)
1589-Power-GA	($1,146,068)	($24,464)	($2,285,823)	$33,672	$4,829,630	$87,698
1550-Low Voltage	($115,802)	($2,925)	($9,894)	($1,217)	$17,489	$168
1551 - Smart Metering Charge Variance					$62,203	$1,616
1595-Disposition of Account Balances Approved in 2008 COS	$14,174	$10,549	($3,004)	($2,443)	$13	($1,177)
1595-Disposition of Account Balances Approved in 2010 IRM	($2,416,490)	($53,338)	$25,686	($126,025)	($1,175)	$254
1595-Disposition of Account Balances Approved in 2012 COS					$1,135,286	$544,624
Group 2						
1508-IFRS-Other Reg. Assets	$436,933	$18,882				
1518-RCVA-Retail	($83,312)	($3,789)				
1548-RCVA-STR	($211,458)	($13,488)				
1555-Smart Meter Capital	1555-included in the rate base					
1556-Smart Meter OMA	1556-included in the rate base					
1562-Deferred PILs Account	$1,151,767	$628,391				
1592-PILs & Tax Variance	($564,143)	($22,383)				
1521-.Special Purpose Charge Assesment Variance Account	($37,397)	$2,194				
TOTAL	**($5,338,866)**	**$488,509**	**($2,822,103)**	**($351,100)**	**$6,347,694**	**$618,186**

Breakdown of energy sales and Cost of Power expenses balances reconciled to the Audited Financial statements

The following Table 9-6 provides a breakdown of energy sales and cost of power expense balances as reported in the audited financial statements and mapped to the appropriate USoA account numbers.

Table 9-6

Guelph Hydro Electric Systems Inc.				
Energy Sales and Cost of Power Expenses Mapped to USoA account				
		2012	**2013**	**2014**
Energy Sales				
Account Description	**Account No**			
Residential Energy Sales	4006	$ 7,183,052	$ 28,767,259	$ 32,919,198
Energy Sales to Large Users	4020	19,995,273	14,193,104	13,812,603
Street Lighting Energy Sales	4025	151,621	186,792	322,554
Sentinel Lighting Energy Sales	4030	4,730	3,091	1,780
General Energy Sales	4035	60,170,713	91,493,673	101,817,185
Energy Sales For Retailers/Others	4055	4,376,833	5,389,905	6,633,717
Billed WMS	4062	10,930,106	10,082,985	9,953,554
Billed NW	4066	10,380,125	10,971,289	11,627,831
Billed CN	4068	8,048,714	8,290,852	8,365,845
Energy Sales before Adjustments Noted Below		$ 121,241,168	$ 169,378,950	$ 185,454,267
	Add(Deduct):			
Retailer Service Charges Activity		139,422	174,386	(106,728)
Reg Asset Disposition Activity		(2,997,650)	(838,169)	-
Smart Meter Rate Rider		193,503	-	-
Total Energy Sales per Audited Financial Statements		$ 118,576,443	$ 168,715,167	$ 185,347,539
Cost of Power				
Account Description	**Account No**			
Power Purchased	4705	91,381,562.75	46,191,259.52	62,444,001.53
Charges - Global Adjustment	4707	-	99,838,066.77	95,980,020.69
Charges-WMS	4708	8,869,473.92	9,076,761.50	9,734,911.45
Cost of Power Adjustments	4710	-	-	-
Charges-One-Time	4712	43,994.89	42,314.19	55,223.27
Charges-NW	4714	11,227,930.55	11,552,107.08	11,917,082.41
System Control and Load Dispatching	4715	-	-	-
Charges-CN	4716	8,348,904.69	8,170,261.29	8,665,205.47
Cost of Power before Adjustments Noted Below		$ 119,871,867	$ 174,870,770	$ 188,796,445
	Add:			
Reg Asset Disposition Activity		-	-	2,047,793.94
Total Cost of Power per Audited Financial Statements		$ 119,871,867	$ 174,870,770	$ 190,844,239
	Loss	$ (1,295,424)	$ (6,155,603)	$ (5,496,700)

As noted in the "Account Balances" section of this Exhibit, regulatory deferral balances are not recognized in Guelph Hydro's audited financial statements, since they are prepared in accordance with International Financial Reporting Standards (IFRS), which upon adoption by Guelph Hydro effective January 1, 2010, did not permit the recognition of regulatory deferral balances in the financial statements. The losses shown from 2012 to 2014 represent the net result each year of the current period transactions being recorded to the regulatory deferral balances. Under IFRS these transactions are recognized in the company's Statements of Comprehensive Income in the year that they are billed or charged.

Statement regarding the IESO Global Adjustment Charge proration

Guelph Hydro confirms that it prorates the IESO Global Adjustment into RPP and Non-RPP portions.

2.12.1 PILs AND TAX VARIANCES FOR 2006 AND SUBSEQUENT YEARS – ACCOUNT 1592

Please see the preceding section entitled "Identification of Group 2 accounts Guelph Hydro will continue and discontinue" for a detailed discussion of the balance in this account.

2.12.2 HARMONIZED SALES TAX DEFERRAL ACCOUNT

Please see the preceding section entitled “Identification of Group 2 accounts Guelph Hydro will continue and discontinue” for a detailed discussion of the balance in 1592 (PILs and Tax Variances for 2006 and subsequent years, Sub-account HST/OVAT ITCs).

2.12.3 ONE-TIME INCREMENTAL IFRS COSTS

Please see the preceding section entitled “Identification of Group 2 accounts Guelph Hydro will continue and discontinue” for a detailed discussion of the balance in 1508 Other Regulatory Assets, sub-account IFRS Transition Costs Variance Account.

2.12.4 ACCOUNT 1575, IFRS-CGAAP TRANSITIONAL PP&E AMOUNTS

Guelph Hydro adopted IFRS in 2011 and submitted its 2012 CoS application (EB-2011-0123) on the basis of MIFRS. The account 1575, IFRS-CGAAP TRANSITIONAL PP&E AMOUNTS is not applicable to Guelph Hydro. Guelph Hydro has not completed Appendix 2-EA_1575.

2.12.5 ACCOUNT 1576, ACCOUNTING CHANGES UNDER CGAAP

Guelph Hydro adopted IFRS in 2011 and submitted its 2012 CoS application (EB-2011-0123) on the basis of MIFRS. The account 1576, Accounting Changes under CGAAP is not applicable to Guelph Hydro. Guelph Hydro has not completed Appendix 2-EB_Account 1576.

2.12.6 RETAIL SERVICE CHARGES

Confirmation on costs incorporated into Account 1518 and Account 1548

Guelph Hydro confirms that all costs incorporated into the variances reported in Accounts 1518 and 1548 are incremental costs of providing retail services.

Table 9-7 provides the account balances of Account 1518 Retail Cost Variance Account ("RCVA") Retail and Account 1548 RCVA STR.

Drivers for the balances in Account 1518 and Account 1548

The drivers of the balances in Accounts 1518 and 1548 are the costs of providing retail services and revenue collected from retailers, the latter being influenced by the number of customers signed up with retailers.

Schedule revenues and expenses incorporated in 1518 and 1548 accounts

In Table 9-8, Guelph Hydro has provided a schedule identifying all revenues and expenses listed by USoA account number, that are incorporated into the variances recorded in Account 1518 and 1548 for 2014. Guelph Hydro does not typically budget for Retail Services Revenue or Service Transaction Requests Revenue due to materiality. The assumption made for Account 1518 and 1548 for the 2015 Bridge Year and the 2016 Test Year is that there is no change in the principal balances of the accounts. The changes in the balances from 2014 to 2016 are the result of the application of carrying charges each year.

1 **Table 9-7: Account Balances - Account 1518 and Account 1548**

Description	USoA #	Pricipal, December 31, 2014	Interest, December 31, 2014	Total Principal and Interest	2.1.7 RRR Balances as at December 31, 2014	Variance to 2.1.7 RRR	Total Claim
Retail Cost Variances, Retail	1518	$ 23,714.80	-$ 1,299.10	$ 22,415.70	$ 22,415.70	0.00	$ 22,415.70
Retail Cost Variances, STR	1548	-$ 21,167.70	-$ 3,254.09	-$ 24,421.79	-$ 24,421.79	0.00	-$ 24,421.79
Total Retail Cost Variance Accounts		**$ 2,547.10**	**-$ 4,553.18**	**-$ 2,006.08**	**-$ 2,006.09**	**$ 0.01**	**-$ 2,006.08**

2

3 **Table 9-8: Accounts 1518 and 1548 - Schedule of Revenues and Expenses: 2014**

Description	2014	Total Principal - 2015 Claim
<u>RCVA, Retail - Account 1518</u>		
Revenues - USoA 4082 - Retail Services Revenue:		
Establishing Service Agreements - Fixed Charge	$ 4,120.00	
Establishing Service Agreements - One-Time Set-up	$ -	
Establishing Service Agreements - Variable Charge	$ 17,408.52	
Distributor Consolidated Billing	$ 10,445.11	
Total Revenues	$ 31,973.63	$ -
<u>Expenses - USoA 5305 - Supervision:</u>		
Labour-related settlement costs	$ 42,186.93	
<u>Expenses - USoA 5315 - Customer Billing:</u>		
Legal Fees - Retailer Complaints	$ -	
EBT Hub	$ 5,200.59	
Total Expenses	$ 47,387.52	
Difference - Account 1518 Adjustment	$ (15,413.89)	$ -
<u>RCVA, STR - Account 1548</u>		
Revenues - USoA 4084 - Service Transaction Requests (STR):		
Request Fee	$ 264.75	
Processing Fee	$ 455.50	
Total Revenues	$ 720.25	$ -
<u>Expenses - USoA 5305 - Supervision:</u>		
Labour-related settlement costs	$ 37,111.81	$ -
<u>Expenses - USoA 5315 - Customer Billing:</u>		
EBT Hub	$ 4,574.95	
Total Expenses	$ 41,686.76	$ -
Difference - Account 1548 Adjustment	$ (40,966.51)	$ -
Total Adjustments to Accounts 1518 & 1548	$ (56,380.40)	**$ -**

4

Statement of Conformity to Article 490

Guelph Hydro confirms that it has followed Article 490, Retail Services and Settlement Variances of the Accounting Procedure Handbook for Accounts 1518 and 1548.

2.12.7 DISPOSITION OF DEFERRAL AND VARIANCE ACCOUNTS

Account balances requested for disposition:

Guelph Hydro is requesting for disposition the following deferral and variance accounts:

- 1508 – Other Regulatory Assets- Deferred IFRS Transition Costs
- 1518 – $RCVA_{Retail}$
- 1548 – $RCVA_{STR}$
- 1532 – Renewable Connection OM&A Deferral Account
- 1533 – Renewable Generation Connection Funding Adder Deferral Account
- 1550 – Low Voltage Variance Account
- 1551 – Smart Metering Entity Charge Variance
- 1555 - Smart Meters Capital – sub-account Zigbee Chip – requested to be included in the 2016 rate base
- 1556 - Smart Meters expenses – sub-account Zigbee chip – depreciation expenses
- 1568 – LRAM Variance Account
- 1580 – Retail Settlement Variance Account - Wholesale Market Service Charges
- 1584 – Retail Transmission Network Charges
- 1586 – Retail Transmission Connection Charges
- 1588 – Retail Settlement Variance Account – Power
- 1589 – Retail Settlement Variance Account - Global Adjustments
- 1595 – Disposition and Recovery of Regulatory Balances Control Account – excluding Subaccount Disposition of Account Balances in 2014

- 1592 - PILs and Tax Variances for 2006 and Subsequent Years, Sub-account HST / OVAT Input Tax Credits (ITCs)

Accounts for which Guelph Hydro is not proposing disposition

Guelph Hydro is proposing all the above accounts for disposition.

Statement of consistency with Audited Financial Statements

The deferral and variance account balances proposed for disposition before forecasted interest are consistent with the 2014 Audited Financial Statements except for the items noted in the next section.

Variance Greater than 5% between amounts proposed for disposition before forecasted interest and applicant's RRR filings:

1532 Renewable Connection OM&A Deferral Account

A total of $9,215 has been added to the December 31, 2014 balance of this account, representing incremental operating expenses directly related to expansions connecting renewable generation facilities, and renewable enabling improvements. The period applicable to these additional expenses is from January 1, 2015 to March 31, 2015. The expenses have been added so that the balances proposed for disposition are consistent with the March 31, 2015 sunset date of the funding adder related to these expenditures which is tracked in Account 1533 Renewable Generation Connection Funding Adder Deferral Account.

1533 Renewable Generation Connection Funding Adder Deferral Account

A total of $30,714 has been added to the December 31, 2014 balance of this account, representing funding adder revenue for the period from January 1, 2015 to March 31,

2015. This revenue has been added so that the balance proposed for disposition is consistent with the March 31, 2015 sunset date of this funding adder.

The following Table 9-9 contains account balances as per the 2014 Audited Financial Statements as of December 31, 2014 and paragraph 2.1.7 of the Electricity Reporting and Record Keeping Requirements version dated March 7, 2014. The interest rates used to record carrying charges are consistent with the Board's prescribed rates.

Table 9-9

Account Description		Principal Amounts as of December 31, 2014	Interest to December 31, 2014	Interest Jan.1 to Dec.31, 2015	
LV Variance Account	1550	$74,826	$504	$892	$76,222
Smart Metering Entity Charge Variance Account	1551	-$18,216	-$37	-$217	-$18,469
RSVA - Wholesale Market Service Charge	1580	-$112,601	$7,928	-$1,343	-$106,016
RSVA - Retail Transmission Network Charge	1584	$197,800	$3,299	$2,359	$203,457
RSVA - Retail Transmission Connection Charge	1586	$290,300	$2,748	$3,462	$296,510
RSVA - Power (excluding Global Adjustment)	1588	-$659,091	$1,602	-$7,860	-$665,350
RSVA - Global Adjustment	1589	$3,283,591	-$8,072	$39,157	$3,314,676
Disposition and Recovery/Refund of Regulatory Balances (2008)	1595	$0	-$1,181	$0	-$1,181
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	$0	$0	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	$89	-$57	$1	$34
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	$0	$0	$0	-$73,465
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	$0	-$0	$0	-$0
Total of Group 1 Accounts (excluding 1589)					**-$288,257**
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition	1508	$54,050	-$6,354	$645	$48,341
Retail Cost Variance Account - Retail	1518	$23,714	-$1,299	$283	$22,698
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	$85,771	$1,714	$1,023	$98,049
Renewable Generation Connection Funding Adder Deferral	1533	-$343,832	-$5,519	-$4,100	-$384,617
Retail Cost Variance Account - STR	1548	-$21,168	-$3,254	-$252	-$24,675
RSVA - One-time	1582	$0	$0	$0	$0
Other Deferred Credits	2425	$0	$0	$0	$0
Total of Group 2 Accounts					**-$240,205**
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)	1592	-$50,797	-$2,582	-$606	-$53,984
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0	$0	$0	$0
Total of Account 1592					**-$53,984**
Smart Meter OM&A Variance[10]	1556				$186,845
LRAM Variance Account	1568	$467,345	$11,437	$5,573	$484,355
Total Balance Allocated to each class (excluding 1589)		-$11,810	$8,948	-$141	**-$395,601**
Total Balance Allocated to each class from Account 1589		$3,283,591	-$8,072	$39,157	**$3,314,676**
Total Balance Allocated to each class (including 1589)		$3,271,781	$876	$39,016	**$2,919,075**

Proposal for 1555- Smart Meter capital – Sub-account Zigbee Chip and 1556- Smart Meter OM&A

Guelph Hydro is requesting for approval to include the 1555 – Smart Meter Capital – Sub-account Zigbee Chip initiative balance of $381,705 (Net Book Value) in the 2016 rate base.

Guelph Hydro is also seeking for approval to recover the 1556 – Smart Meter OM&A – Sub-account Zigbee Chip depreciation balance of $186,845. Guelph Hydro has included the 1556 amount in the EDDVAR Continuity Schedule model, tab 8.Guelph RSVA Model (cells C20 to C32).

As method of recovery, the amount has been only allocated to Residential and General Service below 50 kW on the basis of forecast kWh.

The Zigbee Chip and the Board's findings in Guelph Hydro's 2012 Cost of Service ("COS") proceedings (EB-2011-0123)

Guelph Hydro's procured and deployed smart meters that all have an additional communications chip which uses the Zigbee communications technology to allow the smart meter to communicate with Zigbee-enabled devices in the customer's home or business. The Zigbee chip was an incremental cost of approximately $12 per smart meter. In its evidence presented in the 2012 COS proceedings, Guelph Hydro documented the purpose of the Zigbee chip and technology:

> *Guelph Hydro's smart meters and associated back-office systems meet the minimum specifications set out by O. Reg. 425/06. The meters exceed the specification in one specific area with respect to the inclusion of a communications chip based on the Zigbee technology. This communication chip will enable Guelph Hydro, through the smart meter, to communicate with in-home devices such as displays, thermostats, and Zigbee-equipped smart appliances. There are several advanced applications that can be enabled with this wireless technology including real time price signaling, home area automation, and demand response capability. Inclusion of this technology in the meter will*

> *provide a tool to customers to better educate customers on efficient energy use, and better manage their energy consumption, which in turn will help Guelph Hydro achieve its mandated conservation targets.*
>
> *Guelph Hydro believed that it was prudent to include the communication chip in the smart meters on the basis that the incremental cost to do so was minor ($12.25/meter) in comparison to the alternative of having to replace large volumes of meters before their end of useful life (15 years). In addition, Guelph Hydro believes that substantial customer and electric system benefits would be missed if the chip was not included[1] .*

Board staff noted that Guelph Hydro is the only Ontario distributor that has adopted the Zigbee communication technology. Board staff stated that in principle, the Zigbee chip should be considered as part of smart grid costs in that the Zigbee chip itself has no benefit other than enabling smart grid technologies. However, Board staff did not oppose the inclusion of the incremental capital cost under Guelph Hydro's smart meter program.

Board staff noted that in a previous decision[2] the Board found prudence should be determined in a retrospective factual inquiry, in that evidence must be concerned with the time the decision was made and must be based on facts about the elements that could or did enter into the decision at the time. Board staff argued that Guelph Hydro has been an innovator in adopting the technology notwithstanding that the distributor's use of this technology may have been, in hindsight, premature. Board staff argued that it was not unreasonable to plan for the enabling of smart grid technology in the near future.

In its submission, School Energy Coalition ("SEC") quoted the following Board policy on the cost of technical capabilities in excess of minimum functionality as stated in the *Guideline G-2011-0001: Smart Meter Funding and Cost Recovery – Final Disposition*:

---

[1] E9/T3/S1/p.6

[2] Decision with Reasons, [RP-2001-0032/EB-2001-0367], Enbridge Gas Distribution Inc. issued

December 13, 2002

> *A. Costs for technical capabilities in the smart meters or related communications infrastructure that exceeds those specified in O.Reg. 425/06.* *O.Reg 425/06 specifies that costs that exceed minimum functionality may be approved by the Board for recovery. In deciding whether technical capabilities of installed smart meters or associated communications or other infrastructure that exceed minimum functionality are recoverable, the Board will consider the benefits of the added technical features and the prudence of those costs. Any distributor seeking recovery for these additional capabilities should provide documentation of the additional technical capabilities, the reasons for them and a detailed cost/benefit analysis.*

SEC noted that the Applicant provided sufficient evidence on the technical capabilities and the reasons for them, but failed to provide a business case or provide a cost/benefit analysis. SEC submitted that the costs for the Zigbee chip was small, amounting to 6.4% of the overall cost and agreed with the Applicant that the costs for adding similar functionality at a later point would be significantly higher. SEC noted that although Guelph Hydro was not able to identify specific projects, the Applicant had a general vision of the programs that would benefit from the Zigbee technology. SEC further noted Guelph Hydro's commitment to share what was learned by using the chip with other distributors for the benefit of ratepayers throughout the province.

SEC also noted that now that the technology is in place, the Applicant is in a position to explore the benefits of the technology for a relatively small amount of incremental capital for a potentially large benefit to the ratepayer. SEC submitted that the absence of a business case should not prevent the Applicant from recovering the small incremental cost from ratepayers.

Energy Probe Research Foundation (EP) agreed with Board staff and SEC that the Board should allow the recovery of these costs as part of smart meter costs. EP added that Guelph Hydro should be required to report on the actual use of the functionality provided by the Zigbee chip at various intervals and that this information should be publically available to parties that may wish to utilize some of the functionality provided by the Zigbee chip.

Vulnerable Energy Consumers Coalition ("VECC") generally agreed with Board staff and SEC and added that the environment under which Guelph Hydro was required to make Smart Meter investments was not ideal and did not provide guidance as to what form of investment might be considered prudent. VECC also agreed with SEC that it would have been difficult to provide a business case prior to the purchase of this emerging technology and added that the inherent riskiness of such projects argues for more, rather than less investment planning. VECC submitted that while understandable, generally investments made in the absence of a cost/benefit or business case are indicative of reckless behaviour.

In its reply submission, Guelph Hydro argued that the Zigbee chip costs should be classified as smart meter related cost. Guelph Hydro argued that the concept of "smart grid" as embodied in the *Green Energy and Economy Act* did not exist at the time when it made the decision to include the chip in the smart meter purchased. Guelph Hydro submitted that the chip adds functionality to the meter that enables additional features and potential future services at a reasonable cost.

BOARD FINDINGS

In its Decision and Order on Guelph Hydro's 2012 COS proceeding (EB-2011-0123), the Board found that Guelph Hydro procured and implemented its Smart Meter program in a reasonable and prudent manner and noted that no party took issue with the costs it sought to recover as they relate to the smart meters. The Board therefore approved the recovery of the costs of Guelph Hydro's smart meters, with the exception of the Zigbee chip, and associated back-office systems in the 2012 revenue requirement.

The Board acknowledged that the cost of the Zigbee chip, at approximately $12 per meter is about 6.4% of Guelph's smart meter costs and that Guelph Hydro's average all-in cost per meter of $190.28, inclusive of the Zigbee chip, is comparable to the cost per meter of other similar utilities.

The Board was of the view that this analysis adds little to the assessment of whether the cost of the Zigbee chip is recoverable as a smart meter cost for functionality that is above minimum functionality. In absolute terms the capital investment in the Zigbee chip is $600,000 with an additional estimate of $479,000 yet to be spent to bring the chips into use and is not included in the analysis above. The Board considered this investment to be material in both size and nature and therefore warrants stand-alone scrutiny.

The Board did not accept the submission that supports the recovery of the cost of the Zigbee chip as a smart meter cost on the basis that the amount that Guelph Hydro has spent is comparable to the costs of other utilities and therefore acceptable.

There was no dispute that the potential functionality related to the chip exceeds the functionality that was intended in the establishment of the minimum smart meter functionality requirement. Guelph Hydro was forthright in providing evidence that the Zigbee chip is not needed for smart meter operation and in accordance with O. Reg, 425/06, exceeds minimum functionality.

Guelph Hydro acknowledged that, at the time the decision was made to proceed with the Zigbee chip procurement, there was no cost benefit analysis performed for the Zigbee chip itself and no downstream application was in place to take advantage of it.

It was clear to the Board that Guelph's primary motivation in making the Zigbee chip procurement was to take advantage of the timing of the rollout of the smart meters and to potentially avoid higher cost retrofit installations at a later date, if a potential use for the technology was then identified.

The Board was therefore of the view that the cost of the Zigbee chip is not recoverable as a Smart Meter cost for above minimum functionality.

Zigbee Chip as CDM or Smart Grid Investment

The Board noted that the possible uses for the Zigbee chip, in relation to Conservation and Demand Management (CDM) or Smart Grid initiatives, have not yet fully emerged. As such, the Board was of the view that it needed not make a finding on the prudence of the Zigbee chip investment in Guelph Hydro's 2012 COS proceeding.

The Board was of the view that it is preferable to consider the costs associated with the Zigbee chip, both the capital investment to date and the expected future costs required to fully put the chips into use in the context of the Board's Smart Grid consultation on the development of a Smart Grid and/or CDM. The Board invited Guelph Hydro to avail itself of either of the existing or developing processes related to these areas such that the value proposition of the installed Zigbee chip technology can be more readily defined.

The Board also stated that if, at a future point in time, Guelph Hydro determines that there is potential for the Zigbee chip to provide any ratepayer benefit, Guelph has the option of requesting a prudence review to seek the recovery of its Zigbee chip investment on the basis that it acted prudently in making its investment in the Zigbee chip.

The Board directed Guelph Hydro to record the amounts associated with the Zigbee technology in a sub-account of Account 1555, to be called "Sub-account – Zigbee Chip Initiative". The Board's prescribed short term interest rate has been applied.

Proposal for disposition of deferral accounts for renewable generation connection and smart grid as set out in Filing Requirements "Distribution System Plans - Filing Under Deemed Conditions of Licence"

Guelph Hydro proposes to dispose the balances of the following deferral accounts (please see in this Exhibit, Appendix 9-A DVA Continuity Schedule for year-over-year details of expenditures and collected GEA funding adder)**:**

- 1532 – Renewable Connection OM&A Deferral Account

Guelph Hydro in its 2011 GEA Plan identified a need for additional technical resources in the form of "SmartGrid Technicians" to support the connection of renewable generation projects as well as the further development of "Smart Grid" and related smart grid projects. In the Board's Decision and Order issued on February 22, 2012, one of the 2 additional technical resources identified to facilitate the connection of renewable generation connection projects was approved.

Since then, Guelph Hydro has actively supported these projects through Guelph Hydro's Engineering, Metering and related support departments such as Billing, Settlement, Customer Inquiry, and Finance. As of December 31, 2014, Guelph Hydro had facilitated the connection of 281 microFIT and 28 FIT projects with a total nameplate capacity of 8.537 MW. Direct costs were incurred in 2012, 2013 and 2014 through an Engineering Technician hired and trained to service these renewable generation project customers. Approximately 50% of the Technician's costs, or a total of $85,771 plus an interest of $1,714, were identified and reported in the 1532 deferral account for 2012-2014, although the total cost of providing this service to Guelph Hydro customers is approximately a full time equivalent resource. The calculated interest for 2015 is $1,023.

For 2015 Q1 an additional cost of $9,541 ($9,215 principal and $326 interest) has been estimated.

Guelph Hydro is requesting disposition in the amount of $98,049 for deferral account 1532 through this rate filing.

Based on an analysis completed October 2014, Guelph Hydro expects to connect an additional 360 renewable generation facilities by 2020, with a total additional nameplate capacity of 8.00 MW. While Guelph Hydro does not expect any capital expenditures related to renewable energy generation in its Distribution System Plan, Guelph Hydro does recognize that the Operating, Maintenance and Administrative ("OM&A") costs associated with the existing Engineering Technician are required to service the forecast new renewable generation connections, Guelph Hydro does not anticipate the addition of any new employee resources beyond the Engineering Technician currently trained and supporting these FIT and microFIT applications and connections. Guelph Hydro intends to retain and include the cost of the existing employee to continue providing this service to its customers.

- 1533 – Renewable Generation Connection Funding Adder Deferral Account – effective until March 31, 2015

Following Guelph Hydro's 2012 Cost of Service proceedings (EB-2011-0123), the Board approved Guelph Hydro's GEA plan, subject to a prudence review at the time of Guelph Hydro's next Cost of Service application, and also approved a GEA Funding Adder.

The Board's Decision and Order issued on February 22, 2012, approved the following:

The GEA Funding Adder was implemented with an effective date of April 1, 2012, and a sunset date of March 31, 2015. Since its implementation, Guelph Hydro has collected $343,832 plus $5,519 in interest through to December 31, 2014. The calculated interest for 2015 is $4,100.

Guelph Hydro has also forecast an additional $30,714 to be collected in the January 1 - March 31, 2015 timeframe, with an additional $451.50 of interest expense calculated at the 2015 Q1 interest rate of 1.47%. Guelph Hydro has projected total 2015 interest to be $4,100. The actual 2015 Q1 funding adder collected will not be known until after this rate filing submission, due to the nature and timing of customer invoicing and payment processes. Details of the Board-approved recovery and GEA Funding Adder are included in the following Table 9-10.

Guelph Hydro is requesting disposition in the amount of ($384,617) for deferral account 1533 through this rate filing.

Table 9-10 GEA Renewable Connections - Funding Rate Adder Calculation

	2011		2012		2013		2014		2015	
Net Fixed Assets		$ -		$ -		$ 245,000		$504,500		$532,500
OM&A	$ -		$ 65,250		$ 87,000		$ 87,000		$ 87,000	
WCA	15.0%	$ -	15.0%	$ 9,788	15.0%	$ 13,050	15.0%	$ 13,050	15.0%	$ 13,050
Rate Base		$ -		$ 9,788		$ 258,050		$517,550		$545,550
Deemed ST Debt	4%	$ -	4%	$ 392	4%	$ 10,322	4%	$ 20,702	4%	$ 21,822
Deemed LT Debt	56%	$ -	56%	$ 5,481	56%	$ 144,508	56%	$289,828	56%	$305,508
Deemed Equity	40%	$ -	40%	$ 3,915	40%	$ 103,220	40%	$207,020	40%	$218,220
ST Interest	5.26%	$ -	2.08%	$ 8	2.08%	$ 215	2.08%	$ 431	2.08%	$ 454
LT Interest	4.47%	$ -	5.26%	$ 289	5.26%	$ 7,607	5.26%	$ 15,257	5.26%	$ 16,082
ROE	8.57%	$ -	9.42%	$ 369	9.42%	$ 9,723	9.42%	$ 19,501	9.42%	$ 20,556
		$ -		$ 665		$ 17,545		$ 35,188		$ 37,092
OM&A				**$ 65,250**		**$ 87,000**		**$ 87,000**		**$ 87,000**
Amortization		$ -		$ -		$ 10,000		$ 21,000		$ 23,000
Grossed-up PILs		$ -		$ 131		-$ 95		-$ 6,966		$ 13,852
Revenue Requirement		$ -		$ 66,047		$ 114,450		$136,222		$160,944

Direct Benefit	2011	2012	2013		2014	2015
OM&A	$ -	$ 65,250	**2011 + 2012**	$ 87,000	$ 87,000	$ 87,000
Capital	$ -	$ 797		$ 27,450	$ 49,222	$ 73,944
Direct Benefit % on capital	0.00%	6.00%		6.00%	6.00%	6.00%
Direct Benefit on capital	$ -	$ 48		$ 1,647	$ 2,953	$ 4,437
Total GEA Recovery	$ -	$ 65,298	$ 65,298	$ 88,647	$ 89,953	$ 91,437
Total # of Customers (excl connections)	52,253	52,253	52,253	52,253	52,253	52,253
GEA Rate Adder	$ -	$ 0.10	$ 0.10	$ 0.14	$ 0.14	$ 0.15
Provincial Rate Protection	$ -	$ 749	$ 749	$ 25,803	$ 46,269	$ 69,508
Monthly Adder Amount Paid by IESO	$ -	$ 62	$ 62.41	$ 2,150	$ 3,856	$ 5,792

RSVA Rate Riders for Wholesale Market Participants ("WMP") and Class A customers

In accordance with the Chapter 2 Filing Requirements updated on July 18, 2014, distributors must establish separate rate riders to recover the balances in the RSVAs from WMPs who must not be allocated the RSVA account balances related to charges which WMPs settle directly with the IESO.

In addition, the Filing Requirements require that the distributors who serve Class A customers per O. Reg. 429/04 (i.e. customers greater than 5 MW) must propose an appropriate allocation for the recovery of the global adjustment variance balance based on their settlement process with the IESO.

<u>Wholesale Market Participants ("WMP") Rate Rider for Disposition of Deferral/Variance Accounts</u>

Wholesale energy, Wholesale Market Services, and Global Adjustment for WMPs are charged by the IESO, and therefore WMPs have not contributed to the 1580 RSVA Wholesale Market Service Charge Account, 1588 RSVA Power Account, and 1589 RSVA Global Adjustment Account balances. Guelph Hydro's WMP customers belong to the General Service 50 to 999 kW class.

The WMPs settle the Global Adjustment charge directly with the IESO. Therefore, Guelph Hydro is proposing not to charge a Rate Rider for the Disposition of Global Adjustment Account to the WMP customers.

<u>Class A customers Rate Rider for Disposition of the Global Adjustment Account Balance</u>

Guelph Hydro's settlement process with the IESO offsets to zero the Class A contribution to the 1589 Global Adjustment balance. Therefore, Guelph Hydro is proposing not to charge a Rate Rider for Disposition of Global Adjustment Account balance to Class A customers. Class A customers belong to General Service 1,000 to 4,999 kW and Large Use classes. For details, please see the EDDVAR Continuity Schedule model – Tab. 8. Guelph RSVA model.

Guelph Hydro has developed an additional model in the Board's EDDVAR Continuity Schedule model (Tab 8. Guelph RSVA Model) to calculate the Rate Riders for RSVAs balances disposition for WMPs and Class A customers. By comparison with the Board's EDDVAR model, Guelph Hydro's model does the following:

- Account 1551 -Smart Metering Entity Charge Variance - is allocated to Residential and GS < 50 kW only, based on number of customers,
- Accounts 1580 -RSVA- Wholesale Market Service Charge, and 1588 – RSVA-Power are allocated to all classes based on kWh with WMPs kWh excluded,
- Accounts 1584 –RSVA-Retail Transmission Network Charge and 1586-RSVA-Retail Transmission Connection Charge are allocated to all classes based on kWh - no exclusions,
- Account 1589-RSVA-Global Adjustment is allocated to all classes based on non-RPP kWh with WMP and Class A excluded

All amounts allocated as above are divided by class specific kWh/kW to determine the rate riders.

Guelph Hydro used the WMPs 2014 consumption as the best estimate for 2016 consumption. The allocator is the metered kW.

All other accounts requested for disposition and not mentioned above follow the same allocation methodology as reflected in the OEB's model.

Table 9-11 Guelph Hydro's RSVA Model

Rate Class	Unit	Metered kWh	Metered kW	Billed kWh for Non-RPP Customers	Estimated kW for Non-RPP Customers	No of Customers with Smart Meters (as per 2012 Year Book - IESO 9980 charge is calculated based on these numbers)	1590 Recovery Share Proportion*	1595 Recovery Share Proportion (2008) [1]	1595 Recovery Share Proportion (2009) [1]	1595 Recovery Share Proportion (2010) [1]	1595 Recovery Share Proportion (2012) [1]	1595 Recovery Share Proportion (2014) [1]	1568 LRAM Variance Account Class Allocation ($ amounts)	2012 Board Approved Distribution Revenue	2012 Board Approved Distribution Revenue percentages
RESIDENTIAL	$/kWh	381,586,775		23,070,133	0	50,242		38.08%		38.08%	38.08%	38.08%	6,721	14,475,925	56.18%
GENERAL SERVICE LESS THAN 50 KW	$/kWh	150,174,015		24,853,196	0	4,101		10.15%		10.15%	10.15%	10.15%	34,719	2,552,492	9.91%
GENERAL SERVICE 50 TO 999 KW	$/kW	390,784,407	1,024,992	358,456,143	940,198			26.48%		26.48%	26.48%	26.48%	77,697	3,473,896	13.48%
GENERAL SERVICE 50 TO 999 KW - Wholesale Market Participant	$/kW	6,894,343	12,315	7,201,235	12,863			0.34%		0.34%	0.34%	0.34%		3,640,321	14.13%
GENERAL SERVICE 1,000 TO 4,999 KW	$/kW	563,100,354	1,194,282	563,100,354	1,194,282			14.35%		14.35%	14.35%	14.35%	60,909	49,805	0.19%
LARGE USE - Class A	$/kW	276,633,108	496,250	276,633,108	496,250			10.01%		10.01%	10.01%	10.01%	306,030	1,156,045	4.49%
UNMETERED SCATTERED LOAD	$/kWh	1,700,939		11,440	0			0.21%		0.21%	0.21%	0.21%	-$1,722	3,983	0.02%
SENTINEL LIGHTING	$/kW	21,457	60	2,157	6			0.02%		0.02%	0.02%	0.02%	0	97,865	0.38%
STREET LIGHTING	$/kW	9,628,070	26,693	9,628,070	26,693			0.37%		0.37%	0.37%	0.37%	0	314,980	1.22%
	Total	**1,780,523,469**	**2,754,593**	**1,262,955,835**	**2,670,293**	54,343	**0.00%**	**100.00%**	**0.00%**	**100.00%**	**100.00%**	**100.00%**	**484,355**	25,765,312	100.00%
Total excluding WMP		**1,773,629,126**													
Total excluding WMP and Class A		**1,496,996,017**		**979,121,493**											

1

Allocation of Group 1 Accounts (including Account 1568)

Rate Class	1556	1550	1551	1580	1584	1586	1588	1589	1595 (2008)	1595 (2009)	1595 (2010)	1595 (2012)	1595 (2014)	1568	Total of Group 1 Accounts (excluding 1589 GA and 1568 LRAMVA)	1589 GA for Non-RPP customers
RESIDENTIAL	172,745	16,335	(17,076)	(22,809)	43,603	63,546	(143,146)	78,101	(450)	0	13	(0)	(27,973)	6,721	84,789	78,101
GENERAL SERVICE LESS THAN 50 KW	14,100	6,429	(1,394)	(8,976)	17,160	25,008	(56,335)	84,137	(120)	0	3	(0)	(7,455)	34,719	(11,580)	84,137
GENERAL SERVICE 50 TO 999 KW		16,729		(23,359)	44,654	65,077	(146,597)	1,213,502	(313)	0	9	(0)	(19,453)	77,697	(63,251)	1,213,502
GENERAL SERVICE 50 TO 999 KW - Wholesale Market Participant		295			788	1,148			(4)	0	0	(0)	(250)		1,977	0
GENERAL SERVICE 1,000 TO 4,999 KW		24,106		(33,658)	64,344	93,773	(211,238)	1,906,296	(169)	0	5	(0)	(10,542)	60,909	(73,380)	1,906,296
LARGE USE - Class A		11,842		(16,535)	31,610	46,068	(103,775)		(118)	0	3	(0)	(7,354)	306,030	(38,258)	0
UNMETERED SCATTERED LOAD		73		(102)	194	283	(638)	39	(2)	0	0	(0)	(154)	(1,722)	(346)	39
SENTINEL LIGHTING		1		(1)	2	4	(8)	7	(0)	0	0	(0)	(12)	0	(15)	7
STREET LIGHTING		412		(576)	1,100	1,603	(3,612)	32,594	(4)	0	0	(0)	(273)	0	(1,349)	32,594
																0
TOTAL	186,845	**76,222**	**(18,469)**	**(106,016)**	**203,457**	**296,510**	**(665,350)**	**3,314,676**	**(1,181)**	**0**	**34**	**(0)**	**-$73,465**	**484,355**	**(101,412)**	**3,314,676**

Allocation of Group 2 Accounts (including 1592)

Rate Class	1508 - Deferred IFRS Transition Costs	1518	1531	1532	1533	1548	1592	Total Group 2 including 1592
RESIDENTIAL	27,160	16,366	0	21,013	(82,428)	(17,792)	(30,330)	**(66,011)**
GENERAL SERVICE LESS THAN 50 KW	4,789	1,336	0	8,270	(32,440)	(1,452)	(5,348)	**(24,845)**
GENERAL SERVICE 50 TO 999 KW	6,518	184	0	21,519	(84,415)	(200)	(7,279)	**(63,672)**
GENERAL SERVICE 50 TO 999 KW - Wholesale Market Participant	6,830	1	0	380	(1,489)	(1)	(7,627)	**(1,907)**
GENERAL SERVICE 1,000 TO 4,999 KW	93	14	0	31,008	(121,637)	(15)	(104)	**(90,641)**
LARGE USE - Class A	2,169	1	0	15,233	(59,756)	(2)	(2,422)	**(44,776)**
UNMETERED SCATTERED LOAD	7	178	0	94	(367)	(193)	(8)	**(290)**
SENTINEL LIGHTING	184	2	0	1	(5)	(2)	(205)	**(25)**
STREET LIGHTING	591	4,617	0	530	(2,080)	(5,019)	(660)	**(2,021)**
TOTAL	**48,341**	**22,698**	**0**	**98,049**	**(384,617)**	**(24,675)**	**(53,984)**	**(294,189)**

Rate Class	Units	Total of Group 1 Accounts (excluding 1589 GA and 1568 LRAMVA)	Total Group 2 including 1592	Allocated Balance Excluding 1589 and 1568	Deferral/Variance Account Rate Rider	1589 GA for Non-RPP customers	Global Adjustment Rate Rider
RESIDENTIAL	kWh	$84,789	-$66,011	$18,778	$0.0000	$78,101	$0.0034
GENERAL SERVICE LESS THAN 50 KW	kWh	-$11,580	-$24,845	-$36,426	-$0.0002	$84,137	$0.0034
GENERAL SERVICE 50 TO 999 KW	kW	-$63,251	-$63,672	-$126,924	-$0.1238	$1,213,502	$1.2907
GENERAL SERVICE 50 TO 999 KW - Wholesale Market Participant	kW	$1,977	-$1,907	$70	$0.0057		$0.0000
GENERAL SERVICE 1,000 TO 4,999 KW	kW	-$73,380	-$90,641	-$164,021	-$0.1373	$1,906,296	$1.5962
LARGE USE - Class A	kW	-$38,258	-$44,776	-$83,034	-$0.1673		$0.0000
UNMETERED SCATTERED LOAD	kWh	-$346	-$290	-$636	-$0.0004	$39	$0.0034
SENTINEL LIGHTING	kW	-$15	-$25	-$40	-$0.6588	$7	$1.2067
STREET LIGHTING	kW	-$1,349	-$2,021	-$3,369	-$0.1262	$32,594	$1.2211
		-$101,412	**-$294,189**	**-$395,601**		**$3,314,676**	
TOTAL AMOUNT REQUESTED FOR DISPOSITION						**$2,919,074**	

2

Deferral and Variance Account Disposition Period

Guelph Hydro proposes the disposition of its variance and deferral account balances over a 1-year period.

Allocation of Deferral and Variance Accounts Balances Requested for Disposition

Guelph Hydro has allocated the balances requested for disposition to the rate classes based on the default cost allocation methodology as set out in the Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative, July 31, 2009.

METHOD OF DISPOSITION

Guelph Hydro has allocated all balances to the rate classes based on the default cost allocation methodology as set out in the Report of the Board on Electricity Distributors; Deferral and Variance Account Review Initiative and as expected to be set out in the Board's Guidelines resulting from this proceeding (EB-2008-0046).

1580 Retail Settlement Variance Account - Wholesale Market Service Charges

Disposal of audited balances as of December 31, 2014 and the interest calculated as of December 31, 2015, over a one-year period is requested.

Method of Recovery: Allocation to rate classes on the basis of last Board approved forecasted kWh consumption

1588 Retail Settlement Variance Account – Power

Disposal of audited balances as of December 31, 2014 and the interest calculated as of December 31, 2015, over a one-year period is requested.

Method of Recovery: Allocation to rate classes on the basis of forecasted kWh consumption.

1589 Retail Settlement Variance Account - Global Adjustment

Disposal of audited balances as of December 31, 2014 and the interest calculated as of December 31, 2015, over a one-year period is requested.

Method of Recovery: (As per the Board Staff's Discussion Paper (EB-2008-0046) issued on July 31, 2009): Allocation to rate classes on the basis of forecasted kWh consumption for non-RPP customers.

1508 Other Regulatory Assets

Disposal of audited balances as of December 31, 2014 and the interest calculated as of December 31, 2015, over a one-year period is requested.

Method of Recovery: Allocation to rate classes on the basis of 2012 Board-approved Distribution Revenue.

1518 $RCVA_{Retail}$

Disposal of audited balances as of December 31, 2014 and the interest calculated as of December 31, 2015, over a one-year period is requested.

Method of Recovery: Allocation to rate classes on the basis of forecasted Number of Customers.

1548 $RCVA_{STR}$

Disposal of audited balances as of December 31, 2014 and the interest calculated as of December 31, 2015, over a one-year period is requested.

Method of Recovery: Allocation to rate classes on the basis of forecasted Number of Customers.

1531 – Renewable Connection Capital Deferral Account

Disposal of audited balances as of December 31, 2014 and the interest calculated as of December 31, 2015, over a one-year period is requested.

Method of Recovery: Allocation to rate classes on the basis of forecasted kWh consumption.

1532 – Renewable Connection OM&A Deferral Account

Disposal of audited balances as of December 31, 2014 and the interest calculated as of December 31, 2015, over a one-year period is requested.

Method of Recovery: Allocation to rate classes on the basis of forecasted kWh consumption.

1533 – Renewable Generation Connection Funding Adder Deferral Account

Disposal of audited balances as of December 31, 2014 and the interest calculated as of December 31, 2015, over a one-year period is requested.

Method of Recovery: Allocation to rate classes on the basis of forecasted kWh consumption.

1550 Low Voltage Variance Account

Disposal of audited balances as of December 31, 2014 and the interest calculated as of December 31, 2015, over a one-year period is requested.

Method of Recovery: Allocation to rate classes on the basis of forecasted kWh consumption.

1551 Smart Metering Entity Service Charge

Disposal of audited balances as of December 31, 2014 and the interest calculated as of December 31, 2015, over a one-year period is requested.

<u>Method of Recovery</u>: Allocation to rate classes on the basis of forecasted number of Residential and General Service below 50 kW.

1592 – PILS and Tax Variance

Disposal of audited balances as of December 31, 2014 and the interest calculated as of December 31, 2015, over a one-year period is requested.

<u>Method of Recovery</u>: Allocation to rate classes on the basis of 2012 Board approved Distribution Revenue.

1595 Disposition and Recovery of Regulatory Balances Control Account – excluding Subaccount Disposition of Account Balances in 2014

Disposal of audited balances as of December 31, 2014 and the interest calculated as of December 31, 2015, over a one-year period is requested. The residual account balance was allocated to rate classes in proportion to the recovery share as established when rate riders were implemented.

<u>Method of Recovery</u>: Residual Account balance have been allocated to rate classes in proportion to the recovery share as established when rate riders were implemented.

Table 9-12

2008 EDR Recovery Share- for 1595 Recovery of Regulatory Asset Balances

Residential	38.08%
GS < 50 KW	10.15%
GS 50 to 999 kW	26.82%
GS > 1000 kW	14.35%
Large Use	10.01%
USL	0.21%
Sentinel Lighting	0.02%
Street Lighting	0.37%
	100.00%

PROPOSED DVAs RATES RIDERS

The proposed DVAs rate riders from the disposal of the balances are set out in Table 9-13 below. The requested period of disposition is one year.

Table 9-13
PROPOSED DVAs RATE RIDERS

Rate Class	Units	Total of Group 1 Accounts (excluding 1589 GA and 1568 LRAMVA)	Total Group 2 including 1592	Allocated Balance Excluding 1589 and 1568	Deferral/Variance Account Rate Rider	1589 GA for Non-RPP customers	Global Adjustment Rate Rider
RESIDENTIAL	kWh	$84,789	-$66,011	$18,778	$0.0000	$78,101	$0.0034
GENERAL SERVICE LESS THAN 50 KW	kWh	-$11,580	-$24,845	-$36,426	-$0.0002	$84,137	$0.0034
GENERAL SERVICE 50 TO 999 KW	kW	-$63,251	-$63,672	-$126,924	-$0.1238	$1,213,502	$1.2907
GENERAL SERVICE 50 TO 999 KW - Wholesale Market Participant	kW	$1,977	-$1,907	$70	$0.0057		$0.0000
GENERAL SERVICE 1,000 TO 4,999 KW	kW	-$73,380	-$90,641	-$164,021	-$0.1373	$1,906,296	$1.5962
LARGE USE - Class A	kW	-$38,258	-$44,776	-$83,034	-$0.1673		$0.0000
UNMETERED SCATTERED LOAD	kWh	-$346	-$290	-$636	-$0.0004	$39	$0.0034
SENTINEL LIGHTING	kW	-$15	-$25	-$40	-$0.6588	$7	$1.2067
STREET LIGHTING	kW	-$1,349	-$2,021	-$3,369	-$0.1262	$32,594	$1.2211
		-$101,412	**-$294,189**	**-$395,601**		**$3,314,676**	
TOTAL AMOUNT REQUESTED FOR DISPOSITION						**$2,919,074**	

Request for new deferral account or sub-account

Guelph Hydro is not seeking any accounting order to establish a new deferral/variance account.

APPENDIX 9-A: DVA Continuity Schedule

A complete version of the continuity schedule has been made available on the Board's website in working Microsoft Excel format

APPENDIX 9-B: Decision and Order on Guelph Hydro's 2012 Cost of Service Application file number EB-2011-0123

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2011-0123

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 Guelph Hydro Electric Systems Inc. for an order approving or fixing just and reasonable rates and other charges for the distribution of electricity to be effective January 1, 2012.

BEFORE: Karen Taylor
Presiding Member

Ken Quesnelle
Member

DECISION AND ORDER

February 22, 2012

BACKGROUND

Guelph Hydro Electric Systems Inc. ("Guelph Hydro" or the "Applicant") filed a cost of service application (the "Application") with the Ontario Energy Board (the "Board") on June 30, 2011. The Application was filed under section 78 of the *Ontario Energy Board Act, 1998* (the "Act"), seeking approval for changes to the rates that Guelph Hydro charges for electricity distribution to be effective January 1, 2012. The Board assigned the Application file number EB-2011-0123.

The Board issued a Notice of Application and Hearing on July 18, 2011. Energy Probe Research Foundation ("Energy Probe"), School Energy Coalition ("SEC") and Vulnerable Energy Consumers Coalition ("VECC") applied for intervenor status and cost eligibility. No objections were received regarding the requests for intervenor status and cost eligibility, and the Board approved all such requests.

In Procedural Order No. 1, issued on August 5, 2011, the Board established a schedule for interrogatories, responses and submissions on confidential material filed on June 30, 2011. On August 19, 2011 the Board issued a Decision on Confidentiality.

In Procedural Order No. 2, issued on October 12, 2011, the Board determined the subsequent procedural steps upon completion of the Board's review of the responses to the first round of interrogatories, and issued the Final Issues List. The Board determined that the following issues were not eligible for settlement:

1. Issue 6.1: Is the proposed inclusion of the smart meter costs in the 2012 revenue requirement appropriate?
2. Issue 6.2: Is the proposed disposition of the balances in variance Accounts 1555 and 1556 appropriate?
3. Issue 12.1: Is Guelph Hydro's Green Energy Act Plan, including the Smart Grid component of the plan appropriate?

On October 18, 2011, Procedural Order No. 3 established the procedural steps concerning the request for confidential treatment of certain interrogatory responses. On October 26, the Board issued a Decision on Confidential Treatment of Interrogatory Responses.

A facilitated settlement conference on all eligible issues was held on November 15 and 16, 2011. Energy Probe, SEC and VECC participated in the settlement conference. In Procedural Order No. 4, the Board granted Guelph Hydro a two day extension to file a proposed settlement agreement. A settlement agreement, which incorporated a comprehensive settlement of all eligible issues, was filed with the Board on December 2, 2011.

The Board approved the settlement proposal at the commencement of the oral hearing, which was held on December 5, 2011 to hear the issues ineligible for settlement. The Settlement Agreement is attached as Appendix A.

Guelph Hydro filed its argument-in-chief ("AIC") on the unsettled issues on December 14, 2011. Intervenors and Board staff filed their written submissions on January 4, 2012 and January 6, 2012, respectively. A reply argument was filed by Guelph Hydro on January 19, 2012.

The Board's findings with respect to the issues that were not settled are set out below. Guelph Hydro's Application was completed on the basis of a Modified International Financial Reporting Standards ("MIFRS") accounting standard. Unless otherwise noted, the references below are on a MIFRS basis.

The full record of the proceeding is available at the Board's offices. While the Board has considered all the evidence on record in this proceeding, the Board has chosen to summarise the record in this Decision only to the extent necessary to provide context to its findings.

THE ISSUES

The following issues were raised in the submissions of Board staff and intervenors, and are addressed in this Decision:

- Smart Meter Cost Recovery
- Smart Meter Disposition of Accounts 1555 and 1556
- Green Energy Act ("GEA") Plan
    - Funding Mechanism
    - Enabling Renewable Embedded Generation Connection

- o In-Home Display Messaging Project
- o Electric Vehicle Pilot
- o Smart Grid High School Education
- o Smart Grid Demonstration Home
- o Additional Technical Staffing Resources

Smart Meter Cost Recovery

6.1 Is the proposed inclusion of the smart meter costs in the 2012 revenue requirement appropriate?

Guelph Hydro proposed to recover total capital and operating smart meter expenses of $9,942,320 which translates into a 2012 revenue requirement of $1.61 million. Guelph Hydro's average cost per meter is $190.28. Guelph Hydro stated that its smart meters exceed minimum functionality as set out in Ontario Regulation 425/06 due to the inclusion of a communication chip based on the Zigbee communication technology. Guelph Hydro documented that the incremental capital cost of the Zigbee chip is $12.21 per meter, or approximately $600,000 for all installed smart meters. An estimated additional $479,000 in software and programming costs would be required to operationalize the Zigbee technology. Guelph has not included this latter amount in its revenue requirement calculations for this application.

Guelph Hydro participated in and complied with the London Hydro RFP process for the selection of its smart meter vendor and, as a result, was authorized in accordance with O.Reg. 427/08 for deployment of smart meters primarily to all of its Residential and GS < 50 kW customers. Guelph Hydro filed evidence in accordance with Guideline G-2008-0002: Smart Meter Funding and Cost Recovery, issued by the Board on October 22, 2008, in support of its authorization deploy smart meters and for the associated costs for which it is seeking recovery in this Application.

In their submissions Board staff and the intervenors agreed that the capital and operating expenses for smart meters, apart from the incremental capital costs for the Zigbee chip, were prudently incurred.

The Zigbee Chip

Guelph Hydro's procured and deployed smart meters all have an additional communications chip which uses the Zigbee communications technology to allow the smart meter to communicate with Zigbee-enabled devices in the customer's home or business. The Zigbee chip was an incremental cost of approximately $12 per smart meter. In its evidence, Guelph Hydro documented the purpose of the Zigbee chip and technology:

> Guelph Hydro's smart meters and associated back-office systems meet the minimum specifications set out by O. Reg. 425/06. The meters exceed the specification in one specific area with respect to the inclusion of a communications chip based on the Zigbee technology. This communication chip will enable Guelph Hydro, through the smart meter, to communicate with inhome devices such as displays, thermostats, and Zigbee-equipped smart appliances. There are several advanced applications that can be enabled with this wireless technology including real time price signaling, home area automation, and demand response capability. Inclusion of this technology in the meter will provide a tool to customers to better educate customers on efficient energy use, and better manage their energy consumption, which in turn will help Guelph Hydro achieve its mandated conservation targets.
>
> Guelph Hydro believed that it was prudent to include the communication chip in the smart meters on the basis that the incremental cost to do so was minor ($12.25/meter) in comparison to the alternative of having to replace large volumes of meters before their end of useful life (15 years). In addition, Guelph Hydro believes that substantial customer and electric system benefits would be missed if the chip was not included.[1]

Board staff noted that Guelph Hydro is the only Ontario distributor that has adopted the Zigbee communication technology. Board staff stated that in principle, the Zigbee chip should be considered as part of smart grid costs in that the Zigbee chip itself has no benefit other than enabling smart grid technologies. However, Board staff did not oppose the inclusion of the incremental capital cost under Guelph Hydro's smart meter

[1] E9/T3/S1/p.6

program. Board staff noted that in a previous decision[2] the Board found prudence should be determined in a retrospective factual inquiry, in that evidence must be concerned with the time the decision was made and must be based on facts about the elements that could or did enter into the decision at the time. Board staff argued that Guelph Hydro has been an innovator in adopting the technology notwithstanding that the distributor's use of this technology may have been, in hindsight, premature. Board staff argued that it was not unreasonable to plan for the enabling of smart grid technology in the near future.

In its submission SEC quoted the following Board policy on the cost of technical capabilities in excess of minimum functionality as stated in the *Guideline G-2011-0001: Smart Meter Funding and Cost Recovery – Final Disposition*:

> *<u>A. Costs for technical capabilities in the smart meters or related communications infrastructure that exceeds those specified in O.Reg. 425/06</u>*
> *O.Reg 425/06 specifies that costs that exceed minimum functionality may be approved by the Board for recovery. In deciding whether technical capabilities of installed smart meters or associated communications or other infrastructure that exceed minimum functionality are recoverable, the Board will consider the benefits of the added technical features and the prudence of those costs. Any distributor seeking recovery for these additional capabilities should provide documentation of the additional technical capabilities, the reasons for them and a detailed cost/benefit analysis.*

SEC noted that the Applicant provided sufficient evidence on the technical capabilities and the reasons for them, but failed to provide a business case or provide a cost/benefit analysis. SEC submitted that the costs for the Zigbee chip was small, amounting to 6.4% of the overall cost and agreed with the Applicant that the costs for adding similar functionality at a later point would be significantly higher. SEC noted that although Guelph Hydro was not able to identify specific projects, the Applicant had a general vision of the programs that would benefit from the Zigbee technology. SEC further noted Guelph Hydro's commitment to share what was learned by using the chip with other distributors for the benefit of ratepayers throughout the province.

SEC also noted that now that the technology is in place, the Applicant is in a position to explore the benefits of the technology for a relatively small amount of incremental capital for a potentially large benefit to the ratepayer. SEC submitted that the absence

[2] Decision with Reasons, [RP-2001-0032/EB-2001-0367], Enbridge Gas Distribution Inc. issued December 13, 2002

of a business case should not prevent the Applicant from recovering the small incremental cost from ratepayers.

EP agreed with Board staff and SEC that the Board should allow the recovery of these costs as part of smart meter costs. EP added that Guelph Hydro should be required to report on the actual use of the functionality provided by the Zigbee chip at various intervals and that this information should be publically available to parties that may wish to utilize some of the functionality provided by the Zigbee chip.

VECC generally agreed with Board staff and SEC and added that the environment under which Guelph Hydro was required to make Smart Meter investments was not ideal and did not provide guidance as to what form of investment might be considered prudent. VECC also agreed with SEC that it would have been difficult to provide a business case prior to the purchase of this emerging technology and added that the inherent riskiness of such projects argues for more, rather that less investment planning. VECC submitted that while understandable, generally investments made in the absence of a cost/benefit or business case are indicative of reckless behaviour.

In its reply submission, Guelph Hydro argued that the Zigbee chip costs should be classified as smart meter related cost. Guelph Hydro argued that the concept of “smart grid” as embodied in the *Green Energy and Economy Act* did not exist at the time when it made the decision to include the chip in the smart meter purchased. Guelph Hydro submitted that the chip adds functionality to the meter that enables additional features and potential future services at a reasonable cost.

BOARD FINDINGS

The Board finds that Guelph Hydro has procured and implemented its Smart Meter program in a reasonable and prudent manner and notes that no party takes issue with the costs it seeks to recover as they relate to the smart meters. The Board therefore approves the recovery of the costs of Guelph Hydro’s smart meters, with the exception of the Zigbee chip, and associated back-office systems in the 2012 revenue requirement.

Above Minimum Smart Meter Functionality

The Board acknowledges that the cost of the Zigbee chip, at approximately $12 per meter is about 6.4% of Guelph's smart meter costs and that Guelph Hydro's average all-in cost per meter of $190.28, inclusive of the Zigbee chip, is comparable to the cost per meter of other similar utilities.

The Board is of the view, however, that this analysis adds little to the assessment of whether the cost of the Zigbee chip is recoverable as a smart meter cost for functionality that is above minimum functionality. In absolute terms the capital investment in the Zigbee chip is $600,000 with an additional estimate of $479,000 yet to be spent to bring the chips into use and is not included in the analysis above. The Board considers this investment to be material in both size and nature and therefore warrants stand-alone scrutiny.

The Board does not accept the submission that supports the recovery of the cost of the Zigbee chip as a smart meter cost on the basis that the amount that Guelph Hydro has spent is comparable to the costs of other utilities and therefore acceptable. There are many variables that drive potentially disparate installation costs between distributors. At present, there is no defined range within which the average all-in cost per meter is automatically deemed to be prudent. The prudence of smart meter costs must be demonstrated with the same rigor irrespective of whether the ratepayers are customers of a distributor that has high inherent smart meter installation costs or one that has inherently low costs. This approach is in keeping with the principles that guide the recovery of smart meter costs in rates as set out in O. Reg 426/06 and the Smart Meter Funding Guidelines.

Cost recovery associated with equipment that provides functionality beyond the minimum functionality is set out in Ontario Regulation 426/06, which states:

> *1. (1) In relation to the acquisition of smart meters, a distributor may recover its costs relating to functionality that does not exceed the minimum functionality adopted in Ontario Regulation 425/06 (Criteria and Requirements for Meters and Metering Equipment, Systems and Technology) made under the* Electricity Act, 1998*, subject to final approval by the Board and the Board's review and determination that the agreement entered into for the acquisition is economically prudent and cost effective.*
>
> *(2) In relation to the acquisition of smart meters, a distributor may not recover its costs relating to functionality that exceeds the minimum functionality adopted in Ontario Regulation 425/06 (Criteria and Requirements for Meters and Metering Equipment,*

> *Systems and Technology) made under the Electricity Act, 1998 unless the costs are approved by the Board.*
>
> *(3) In reaching a decision under subsection (2), the Board may consider the matters that it considers appropriate, including evidence that the functionality that exceeds the minimum functionality adopted in Ontario Regulation 425/06 (Criteria and Requirements for Meters and Metering Equipment, Systems and Technology) made under the Electricity Act, 1998 benefits the distributor's consumers.*

There is no dispute that the potential functionality related to the chip exceeds the functionality that was intended in the establishment of the minimum smart meter functionality requirement. Guelph Hydro was forthright in providing evidence that the Zigbee chip is not needed for smart meter operation and in accordance with O. Reg 425/06, exceeds minimum functionality.

Guelph Hydro acknowledged that, at the time the decision was made to proceed with the Zigbee chip procurement, there was no cost benefit analysis performed for the Zigbee chip itself and no downstream application was in place to take advantage of it.

It is clear to the Board that Guelph's primary motivation in making the Zigbee chip procurement was to take advantage of the timing of the rollout of the smart meters and to potentially avoid higher cost retrofit installations at a later date, if a potential use for the technology was then identified.

The Board is therefore of the view that the cost of the Zigbee chip is not recoverable as a Smart Meter cost for above minimum functionality.

Zigbee Chip as CDM or Smart Grid Investment

Board staff submitted that the Board should apply a prudence review analysis that considers the facts of and what could have been reasonably known to Guelph Hydro at the time of the Zigbee chip procurement. In the Board's view the type of analysis that Board Staff suggests would best be performed when the possibility of any of the potential chip benefits that Guelph has envisioned has run its course. The Board concurs and notes that the possible uses for the Zigbee chip, in relation to Conservation and Demand Management (CDM) or Smart Grid initiatives, have not yet fully emerged. As such, the Board is of the view that it need not make a finding on the prudence of the Zigbee chip investment in this proceeding.

At the current time, it is clear that the Zigbee chip does not yet provide a benefit to ratepayers and it would therefore be inappropriate for the investment to be included in rate base.

The Board is of the view that it is preferable to consider the costs associated with the Zigbee chip, both the capital investment to date and the expected future costs required to fully put the chips into use in the context of the Board's Smart Grid consultation on the development of a Smart Grid and/or CDM. The Board invites Guelph Hydro to avail itself of either of the existing or developing processes related to these areas such that the value proposition of the installed Zigbee chip technology can be more readily defined.

If, at a future point in time, Guelph Hydro determines that there is no potential for the Zigbee chip to provide any ratepayer benefit, Guelph has the option of requesting a prudence review to seek the recovery of its Zigbee chip investment on the basis that it acted prudently in making its investment in the Zigbee chip.

The Board directs Guelph Hydro to record the amounts associated with the Zigbee technology in a sub-account of Account 1555, to be called "Sub-account – Zigbee Chip Initiative". The Board's prescribed short term interest rate shall apply.

Smart Meter Disposition of Accounts 1555 and 1556

6.2 Is the proposed disposition of the balances in variance accounts 1555 and 1556 appropriate?

Guelph Hydro requested a Smart Meter Disposition Rate Rider ("SMDR") to dispose of the residual deferred revenue requirement (total smart meter revenue requirement offset by total smart meter funding) for the historic period leading up to the test year. As updated on November 23, 2011 Guelph Hydro sought approval of a credit amount of $84,936 for the SMDR, using the following cost allocation methodology:

- The return and amortization was allocated using the allocation of Account 1860 in the cost allocation model;
- OM&A was allocated based on the number of meters installed for each class; and

- PILs was allocated based on the revenue requirement allocated to each class before PILs.

Table 1 shows the result of this cost allocation methodology.

Table 1

	Total	Residential	General Service Less than 50 kW	General Service 50 to 999 kW	General Service Greater 1,000 to 4,999 kW	Large User
$2,335,949.75	$2,335,949.75	$1,839,594.58	$307,911.03	$169,079.20	$15,327.14	$4,037.79
Percentage of costs allocated to customer classes_Board Staff TCQ 19 b	100.00%	78.75%	13.18%	7.24%	0.66%	0.17%
$2,420,885.78						
-$84,936.03						
Allocated per Class_Board Staff TCQ 19 d		-$66,888.37	-$11,195.76	-$6,147.78	-$557.30	-$146.82
Number of Metered Customers		47,848	3,788	569	44	4
Smart Meter Disposition Rate Rider_Board Staff TCQ 19 e		-$0.12	-$0.25	-$0.90	-$1.07	-$3.06

Board staff submitted that this approach which allocates the net residual deferred revenue requirement is consistent with a proxy approach approved by the Board in proceeding EB-2010-0209 (Powerstream Inc.). However, Board staff noted that Guelph Hydro allocated costs to classes that were not part of the smart meter program. Board staff also noted that in a subsequent decision in PowerStream Inc. final smart meter disposition (EB-2011-0128), the Board approved a cost allocation based on a class specific revenue requirement offset by class specific smart meter funding, based on full cost causality. Board staff invited Guelph Hydro to comment in its reply submission on any impediment to implementing the methodology approved by the Board in the EB-2011-0128 proceeding and to provide the results of using this approach.

EP submitted that the credit amount of $84,936 is appropriate. EP supported a cost allocation methodology based on class specific revenue requirement offset by class specific smart meter funding. EP added that Guelph Hydro should take into consideration the Board's finding in Hydro Ottawa's proceeding (EB-2011-0054), where the use of general assumptions and estimates to complete data to determine class-specific SMDR's was found to be reasonable.

Similarly, VECC noted that the principle of cost causality is best represented by a cost allocation of smart meter costs based on class specific smart meter revenue requirements. VECC submitted that a revised SMDR should be allocated to the rate classes receiving smart meters using full cost causality. VECC submitted that Guelph Hydro appear to have adequate cost information to calculate a class specific SMDR.

SEC made no submission on this issue.

In its reply submission, Guelph Hydro stated that it does not have the details related to the allocation of the smart meter costs per customer classes (i.e. Residential and GS<50kW) and that the cost allocation methodology proposed by VECC and approved by the Board in the EB-2011-0128 proceeding is not feasible. Guelph Hydro submitted that distributors were not required to keep track of costs at such level of detail. Guelph Hydro provided the results of using the cost allocation methodology approved by the Board in the EB-2011-0206 (PowerStream) and EB-2011-0073 (Oshawa PUC Networks) proceedings. Guelph Hydro used the following methodology to allocate the costs to the Residential and General Service less than 50 kW:

1. The Weighted Meter Capital (CWMC) allocator/percentage for the Residential class was calculated as the total residential meter capital expenses divided by the total meter capital expenses (please see the Cost Allocation Model – tab E2-Allocators, updated on September 30, 2011).

2. The CWMC for GS< 50 kW is the difference between the 100% and the Residential CWMC of 74.03%.

3. The Total Return on Capital, Amortization and Interest Expenses were allocated to the customer class using the CWMC allocator.

4. The Operating Expenses were allocated based on the number of Smart Meters installed for each class.

5. The Gross –up Taxes and PILs were allocated based on the revenue requirement allocated to each class before PILs.

6. The revenue generated from Smart meter Funding Adder was allocated to the customer class based on the percentage of costs allocated to customer classes.

As a result, Guelph Hydro submitted the following SMDR for those customer classes:

Table 2

	Residual deferred Revenue Requirement $	Percentage of Costs allocated to Classes %	Number of Customers	Smart Meter Disposition Rate Rider $ / month
Total	**(84,936)**	**100.00**	**52,253**	
Residential	**(66,888)**	**78.75**	**47,848**	**(0.12)**
GS<50 kW	**(18,047)**	**21.25**	**3,788**	**(0.40)**

Board Findings

The Board will approve a Smart Meter Disposition Rider to dispose of the residual deferred revenue requirement for the historic period leading up to the test year, subject to the adjustment to remove the cost of the Zigbee chip and the associated interest costs. The Board directs Guelph to recalculate the balance in Accounts 1555 and 1556 on this basis. The Board approves the disposition of the recalculated balance of variance Accounts 1555 and 1556 on a final basis as of December 31, 2011 inclusive of applicable interest to December 31, 2011.

In its letter, dated December 15, 2011 to All Licensed Electricity Distributors re: Updates to Guideline G-2008-0002: Smart Meter Funding and Cost Recovery and Smart Meter Model, the Board stated:

> *The model does not address cost allocation. Distributors should, where practical and where the data is available, use class-specific rate riders to be calculated based on full cost causality. The methodology approved by the Board in its decision to PowerStream Inc.'s 2011 smart meter application (EB-2011-0128) should serve as a suitable guide. A uniform rate rider approach would be suitable only where adequate data is not available.*

The Board notes that Guelph does not have the details related to the allocation of smart meter costs per customer classes (i.e., Residential and GS<50 kW) and that applying the cost allocation methodology approved in the EB-2011-0128 proceeding is not feasible. The Board will approve the revised cost allocation methodology provided in

Guelph Hydro's reply's submission, as it is consistent with the approach approved by the Board in the EB-2010-0209 and EB-2011-0073 proceedings.

Green Energy Act ("GEA") Plan

12.1 Is Guelph Hydro's Green Energy Plan, including the Smart Grid component of the plan appropriate?

On November 23, 2011 Guelph Hydro filed an updated Green Energy Plan. The updated capital and operating expenses are shown in Table 3 below.

Table 3

Capital Summary

	2011 ($000)	2012 ($000)	2013 ($000)	2014 ($000)	2015 ($000)	Total ($000)
Renewable Generator Connection Upgrades	$0	$0	$500	$50	$50	$600
In-Home Display Messaging Project	$0	$479	$0	$0	$0	$479
Electric Vehicle Pilot	$0	$50	$0	$0	$0	$50
Smart Grid High School Education	$0	$0	$0	$0	$0	$0
Demonstration "Smart Grid-Smart Home"	$0	$0	$0	$0	$0	$0
Additional Technical Staffing Resources	$0	$0	$0	$0	$0	$0
Total	$0	$529	$500	$50	$50	$1,129

OM&A Summary

	2011 ($000)	2012 ($000)	2013 ($000)	2014 ($000)	2015 ($000)	Total ($000)
Renewable Generator Connection Upgrades	$0	$0	$0	$0	$0	$0
In-Home Display Messaging Project	$0	$92	$92	$92	$92	$368
Electric Vehicle Pilot	$0	$200	$290	$30	$20	$540
Smart Grid High School Education	$0	$75	$35	$35	$20	$165
Demonstration "Smart Grid-Smart Home"	$0	$45	$130	$55	$10	$240
Additional Technical Staffing Resources	$0	$174	$174	$174	$174	$696
Total	$0	$586	$721	$386	$316	$2,009

Total Capital and OM&A Expenditures

	2011 ($000)	2012 ($000)	2013 ($000)	2014 ($000)	2015 ($000)	Total ($000)
Capital	$0	$529	$500	$50	$50	$1,129
OM&A	$0	$586	$721	$386	$316	$2,009
Total	$0	$1,115	$1,221	$436	$366	$3,138

On December 12, 2011 Guelph Hydro revised the GEA operating expense as shown in Table 4 below.

Table 4

	2011 ($000)	2012 ($000)	2013 ($000)	2014 ($000)	2015 ($000)	Total ($000)
"Connections OM&A" - Additional Technical Staffing Resources	$0	$65	$83	$91	$104	$344
In-Home Display Messaging Project	$0	$92	$92	$92	$92	$368
Electric Vehicle Pilot	$0	$200	$290	$30	$20	$540
Smart Grid High School Education	$0	$75	$35	$35	$20	$165
Demonstration "Smart Grid-Smart Home"	$0	$45	$130	$55	$10	$240
"SmartGrid OM&A" - Additional Technical Staffing Resources	$0	$109	$91	$83	$70	$352
Total	$0	$586	$721	$386	$316	$2,009

Guelph Hydro noted that it does not meet the threshold for filing a Detailed GEA Plan and, as such, requested the approval of a Basic GEA Plan including the following elements:

- GEA Funding Adders
- Enabling Renewable Embedded Generation Connection
- In-Home Display Messaging Project
- Electric Vehicle Pilot
- Smart Grid High School Education
- Smart Grid Demonstration Home
- Additional Technical Staffing Resources

<u>GEA Funding Adders</u>

Guelph Hydro proposed the establishment of two different funding adders separating renewable generation and smart grid funding. On November 24, 2011 Guelph Hydro updated its proposed funding adders as shown in Table 5 below. The Renewable

Connection Rate Adder was determined based on a direct benefit calculation to Guelph Hydro's rate payers.

Table 5

	2012 $	2013 $	2014 $	2015 $
Renewable Connection Rate Adder – Direct Benefit	0.10	0.13	0.15	0.17
Smart Grid Rate Adder	0.83	1.02	0.47	0.34

Board staff and EP submitted that given the uncertainty surrounding some of the projects and associated costs, final approval of the GEA plan is premature. Nevertheless, Board staff and EP argued that advance funding through a funding adder with a subsequent prudence review at a later date is appropriate.

VECC submitted that the Board should make a clear determination on the prudence of the plan for the next three years (or until next rebasing). Consequently, VECC argued that the preferred approach for the GEA plan cost recovery would be a rate rider and the establishment of a variance account to ensure that any over collection of funds can be returned to the rate payer. VECC also argued that the utility should not be able to seek relief for any overspending.

SEC did not make a submission on this matter.

In its reply submission, Guelph Hydro stated that it is seeking approval for its GEA Plan (which implies approval of a funding adder) and noted that it expects a prudence review at the time of its next cost of service application. Guelph Hydro also noted that any differences between the collected revenues by means of a funding adders and the actual GEA plan cost will be disposed of following the Board's decision in its next cost of service application.

Board Findings

Subject to the findings set out below on each of the Projects/Investments that comprise Guelph's GEA Plan, the Board will approve Guelph Hydro's GEA plan, subject to a prudence review at the time of Guelph Hydro's next cost of service application, and will approve a GEA Funding Adder.

Enabling Renewable Embedded Generation Connection

On November 23, 2011 Guelph Hydro updated its GEA Plan to include the following capital and operating expenses for a Renewable Embedded Generation Connection project:

Table 6

	2012 $	2013 $	2014 $	2015 $	Total $
CapEx	0	500,000	50,000	50,000	600,000
OM&A	65,000	83,000	91,000	104,000	344,000

In response to cross examination, Guelph Hydro revised the forecast number of projects and anticipated renewable generation as shown in Table 7 below:

Table 7

Revised TABLE 7: NUMBER OF ANTICIPATED RENEWABLE GENERATION CONNECTIONS [MICROFIT/FIT]

Number of Renewables by Year	*Prior to 2011*	*2011*	*2012*	*2013*	*2014*	*2015*	*Total*
Micro Generation (<= 10 kW)	29	56	50	40	40	40	***255***
Small Generation (<= 250 kW)	0	5	24	7	7	7	***50***
Small Generation (> 250 kW,<= 500 kW)	0	0	1	0	0	0	***1***
Mid-Size Generation (> 500 kW, <= 10 MW)	0	0	0	1	1	1	***3***
Total	***29***	***61***	***75***	***48***	***48***	***48***	***309***

of the 56 Micro Generation projects (< =10 kW)forcasted for 2011, 46 projects have been connected YTD in 2011
of the 5 small Generation projects (<= 250 kW) forcasted for 2011, 2 projects have been connected YTD in 2011

Revised TABLE 8: ANTICIPATED RENEWABLE GENERATION CONNECTION GENERATION IN MW [MICROFIT/FIT]

Renewables by Year [MW]	*Prior to 2011*	*2011*	*2012*	*2013*	*2014*	*2015*	*Total*
Micro Generation (<= 10 kW)	0.13	0.38	0.34	0.21	0.21	0.21	***1.47***
Small Generation (<= 250 kW)	0.00	1.34	5.28	1.12	1.12	1.12	***9.98***
Small Generation (> 250 kW,<= 500 kW)	0.00	0.00	0.50	0.00	0.00	0.00	***0.50***
Mid-Size Generation (> 500 kW, <= 10 MW)	0.00	0.00	0.00	10.00	3.00	1.14	***14.14***
Total	***0.13***	***1.72***	***6.12***	***11.33***	***4.33***	***2.47***	***26.09***

On December 12, 2011 Guelph Hydro provided an updated cost estimate of $524,000 (with a tolerance of +/- 15%) in 2013 in connection with a 10MW project. Guelph Hydro's request for the amounts of $50,000 in 2014 for a 3 MW project and the amount of $50,000 in 2015 for a 1.14 MW project remained unchanged.

Guelph Hydro also updated its operations, maintenance and administration ("OM&A") cost claim to include one full time employee ("FTE"), dedicated mainly for connection activities related to FIT and microFIT generation projects. The inclusion of this operational expense is discussed later in this Decision.

Board staff accepted Guelph Hydro's explanation that the increase in the forecast for 2012 is based on projects currently in the queue for connection in both the FIT and mircoFIT categories in 2011 and 2012. Board staff supported the capital and operating costs as reasonable.

EP agreed with Board staff.

SEC made no submission on this issue.

VECC made no submission on this issue with the exception of the staffing addition.

Similarly, Guelph Hydro made no reply submission with the exception of the technical staffing resource.

BOARD FINDINGS

The Board notes that no party took issue with approval of this element of Guelph's GEA Plan. The Board finds Guelph's plan with respect to this element to be reasonable and approves the Renewable Generation Connection Upgrades portion of Guelph's GEA Plan as filed.

In-Home Display Messaging Project

Guelph Hydro stated that its smart grid related projects include an in-home display ("IHD") messaging project, which will leverage the AMI network, as well as the Zigbee chip and will provide a mechanism for consumer behavioral change.

In the updated GEA Plan of November 23, 2011, Guelph Hydro requested capital and operating expenditures for the IHD messaging project as set out in the table below:

Table 8

	2012 $	2013 $	2014 $	2015 $	Total $
CapEX	479,000	0	0	0	479,000
OM&A	92,000	92,000	92,000	92,000	368,000

The nature of the expenditures include: costs for the design, acquisition, installation, system integration, commissioning and training for a back-office hardware and software solution that will manage the community's IHD inventory, smart meter – IHD pairing and device security, as well as provide a tool for creating and managing messaging. Also included in the project are OM&A costs for annual software licensing fees and system operational support.

Guelph Hydro noted that the actual IHD would not be funded through this project budget, as the assumption is that IHDs will be funded though a new 2011 OPA Tier 1 CDM program, which is expected to replace the *peaksav*er*TM* residential demand response program. In response to parties seeking clarification on the demarcation point between CDM and Smart Grid, Guelph Hydro was not able to establish such a demarcation point. Guelph Hydro acknowledged that any energy and demand savings associated with the IHD would need to be reflected in Guelph Hydro's CDM targets.

Board staff had several issues with respect to the IHD messaging project. The first concern was with the demarcation point between this project as a CDM measure versus a smart grid initiative and the ensuing cost recovery mechanism. Secondly, Board staff questioned the distributor's role as a provider of behind-the-meter services, a matter currently under review by the Board. Lastly, Board staff questioned whether Guelph Hydro's role as a provider of a messaging service, available to third parties, falls outside of Guelph Hydro's electricity distribution core business.

Board staff submitted that this project is premature at this point in time and noted that the distributor's role in behind-the-meter services is currently a "grey area". Board staff noted that the question of whether behind-the-meter services should fall within the regulated monopoly rate base or should be a competitive activity has not been addressed by the Board. Board staff further noted that this question has been posed for discussion with stakeholders in the Board's Renewed Regulatory Framework consultation, currently underway.

Board staff also argued that no third party should have access to the messaging service without a user fee. Board staff submitted that Guelph Hydro re-submit an IHD project, accompanied by a full business case, at a later point.

SEC submitted that the Basic GEA plan, including the IHD project should be approved as filed. While SEC agreed that a key question is the extent to which this project evolves into an OPA-funded CDM program, SEC submitted that the benefits will outweigh the costs. SEC submitted that it is important that utilities start, as soon as possible, to promote the capabilities that come with greater information on energy use. However, SEC agreed that the approval of this project should not amount to implicit approval for Applicants to enter the behind-the-meter services business as a regulated activity. Therefore, SEC proposed that the Board set a limit of 5% of residential customers that can have utility-supplied IHD and require the Applicant to actively engage the private sector as partners in the delivery of services under the project.

EP agreed with Board staff that this project is premature. EP expressed concern regarding the impact of third party messaging and submitted that allowing third party messaging is also premature. EP submitted that if the Board were to approve third party access, a user fee should apply. Revenue from these fees should be placed in a deferral account to be returned to ratepayers at a later date. EP agreed with SEC that the project should be limited to 5% of the residential customers and added that this limit should be expanded to include 5% of GS<50kW as well.

VECC supported Guelph Hydro proposal and submitted that the IHD project is the only project in the Applicant's plan to provide ratepayers a return on the Zigbee investment in the form of lower energy bills. VECC disagreed with the concerns raised by Board staff and EP regarding the demarcation between CDM and smart grid and noted that it is a matter of semantics rather than substance. VECC agreed with SEC to cap this demonstration project at 5% and added that Guelph Hydro should be directed to create a specific marketing approach to low-income consumers.

In its reply submission, Guelph Hydro argued that its interest in this project at this time is limited to proving the capability of the underlying smart meter infrastructure, understanding how effectively the IHD can provide enhanced customer service and as a tool for the customer to help manage and/or reduce their energy costs. Guelph Hydro submitted that its does not see a role in providing behind-the-meter services unless there is a direct tie in to its core business. Guelph Hydro stated that a viable business case would be determined after the project is completed.

Guelph Hydro also agreed that there is no clear demarcation between CDM and Smart Grid initiatives in that the technology supports both. Guelph Hydro noted that in Ontario the earlier mandatory implementation of smart meters has removed the debate whether smart meters are a smart grid activity.

With respect to third party messaging, Guelph Hydro submitted that it will control all messaging and not allow any third party access. Guelph Hydro also submitted that the issue of a user fee should be addressed at a future date. In response to VECC's submission, Guelph Hydro agreed to include low-income customers and seniors to be part of the selection process to determine the sample population participating in this program.

BOARD FINDINGS

The Board will not approve the In-Home Display Messaging Project. Although this project may potentially take advantage of the functionality provided by the Zigbee chip, the vision for the project, as articulated by Guelph, suggests that the costs associated with the project are more appropriately classified as CDM costs and/or, potentially, as Smart Grid costs. The Board believes that the distinction between the two is material, as CDM costs relating to province-wide programs sponsored by the OPA and Board approved programs are recovered via the GAM, not through Board-approved distribution rates.

Moreover, Guelph has not applied for a Board-approved CDM program and even if this were the case, CDM program development costs are generally not recoverable unless the program is approved by the Board. The Board encourages Guelph to continue to work with the OPA to develop a province-wide, IHD CDM program. Alternatively, Guelph may also wish to consider an application for a Board-approved CDM program.

The Board also notes that some elements of this proposed project relate to smart grid functions behind the meter. The distributor's role with respect to behind-the-meter services is a question that has not yet been addressed by the Board. The Board agrees with Board staff that this matter is currently being considered in the Renewed

Regulatory Framework consultation via the Staff Discussion Paper in regard to the Establishment, Implementation and Promotion of a Smart Grid in Ontario. As such, the Board is of the view that approval would pre-empt the consultation and is therefore premature.

Electric Vehicle Pilot

As part of its GEA plan, Guelph Hydro submitted an electric vehicle ("EV") pilot project with the following amounts:

Table 9

	2012 $	2013 $	2014 $	2015 $	Total $
CapEX	50,000	0	0	0	50,000
OM&A	200,000	290,000	30,000	20,000	540,000

Guelph Hydro proposed a capital expenditure of $50,000, which includes the purchase of an electric vehicle. The pilot project envisioned partnering with the City of Guelph and other local agencies and businesses, to install well signed and well branded electric vehicle charging stations in a number of high-visibility locations in the community. Guelph Hydro intends to install a small number of charging stations at strategic residential locations in order to record and analyze consumption patterns.

Guelph Hydro acknowledged that the objective of this demonstration project is to learn about consumer behaviour and the implication on different rate plans in the future, rather than the impact of electric vehicles on its distribution system. Guelph Hydro stated that this project includes the use of a customized cube van that can serve as a model for fleet owner/operators. Guelph Hydro noted that it intends to leverage the Zigbee chip by exploring EV charging stations that are also equipped with Zigbee technology, and by understanding how these systems could read time-of-use rate buckets and adjust consumption according to consumer-selected criteria. Guelph Hydro noted that the relatively shorter commuting distances for Guelph residents would constitute a different test environment as compared to some other utilities.

Although Board staff agreed that Guelph Hydro's short commuting distances provide a favourable environment for an EV pilot project, Board staff noted that Guelph Hydro failed to produce a clear business case or demonstrate how Guelph Hydro will avoid duplication with other EV pilots. Nevertheless, Board staff agreed that the lessons gained from this project would be of benefit to the province as a whole.

SEC submitted that Guelph Hydro's EV pilot project, in contrast to proposals by other distributors, is outward-focused. SEC noted at least two components of particular value. First, the value of the addition of a cube van to fleet owners, and secondly the testing of "smart recharging" where vehicle owners can program charging parameters into their system so that it can be done more efficiently. SEC noted that this pilot seeks to explore efficiency gains in electric vehicle charging, similar to the programmable thermostat. For those reasons, SEC submitted that the proposed spending on this program should be approved.

EP adopted SEC's submissions on this issue.

VECC noted that EV technologies are sufficiently motivated and funded by government and private sector initiatives. VECC argued that Guelph Hydro has not provided any compelling evidence as to how this project would add significant incremental value. Furthermore, VECC submitted that the pilot is ill defined.

In its reply submission, Guelph Hydro disagreed with VECC that the EV project is ill defined and submitted that there was no necessity to submit a full-fledged business case for this project. Guelph Hydro noted that its understanding of this new technology and its plans for an EV pilot project continued to evolve during this proceeding. Guelph Hydro submitted that it would like to take the lead in modeling the use of an electric cube van as part of its fleet and undertake research into different rate plans and their impact on consumers' behaviour. Guelph Hydro agreed with SEC and EP that its pilot project is outward-focused and noted that Guelph Hydro is in a position to implement added value due to the capabilities enabled by the Zigbee technology. Guelph Hydro further noted that there would be value in conducting research with various charging station manufacturers and the public into different settlement schemes for EV charging done in public and semi-public spaces.

BOARD FINDINGS

The Board will not approve Guelph Hydro's proposed Electric Vehicle Pilot. The proposed pilot is not designed to address whether there are any issues with Guelph

Hydro's distribution system arising from the addition of electric vehicles. To the contrary, Guelph Hydro clearly indicated that its distribution network is fairly modern and has been upgraded regularly, such that the utility does not anticipate major capacity issues arising from the addition of electric vehicles. Rather, Guelph Hydro indicated that the purpose of the pilot is to learn about customer behaviour and the implication on different rate plans in the future. The Board agrees with VECC that other government and private sector initiatives exist. The Board notes that the demarcation point between the rate-regulated entity and non-regulated service providers and the role of the distributor in non-monopoly activities have not yet been addressed by the Board. The Board is of the view that these issues are currently being considered in the Renewed Regulatory Framework consultation via the Staff Discussion Paper in regard to the Establishment, Implementation and Promotion of a Smart Grid in Ontario. As such, the Board is of the view that approval of this pilot would pre-empt the consultation and is therefore premature.

Smart Grid High School Education

Guelph Hydro requested the following operational expenses for a high school education program:

Table 10

	2012 $	**2013 $**	**2014 $**	**2015 $**	**Total $**
CapEx	0	0	0	0	0
OM&A	75,000	35,000	35,000	20,000	165,000

Guelph Hydro proposed the development and implementation of a high school smart grid education component to be delivered through the local school boards. Guelph Hydro noted a need to engage the minds of the future to enter into and embrace the opportunities that smart grid will present. The program included two units: benefits of a smart grid and careers in the smart grid industry.

Board staff noted that the *Filing Requirements: Distribution System Plans – Filing under Deemed Condition of Licenses (EB-2009-0397)* ("DSP Filing Requirements"), issued March 25, 2010 state that "at the present time, smart grid development activities and expenditures should be limited to smart grid demonstration projects, smart grid studies or planning exercises and smart grid education and training". Under the third point, smart grid education and training, the DSP Filing Requirements require a distributor to describe how the project will further the distributor's understanding of smart grid development or otherwise aid in developing a smart grid.

Board staff was of the view that this project is outside the parameters of a smart grid education and training project as defined in the DSP Filing Requirements. Board staff noted that the DSP Filing intend to further a distributor's understand of smart grid development by building internal expertise. Board staff submitted that the costs associated with this project should not be eligible under a Smart Grid training program.

EP agreed with Board staff's submission.

SEC submitted this project should be supported since the Board has consistently supported programs that allow gas and electricity utilities to partner with local school boards to raise awareness on conservation, safety and other issues. SEC argued that under the strict wording of the DSP Filing Requirements this projects does comply in that it helps the distributor understand consumer responses to the new technology and creates a potentially knowledgeable and motivated pool of workers. SEC acknowledged that the DSP Filing Requirements did not specify community education projects but argued that smart grid development has evolved since the issuance of the filing requirements. SEC further noted that individual Board panels can exercise their discretion to consider plans that go beyond the minimum. SEC, therefore, argued that the Board should approve this expense because in substance it is a good project.

VECC agreed with SEC and that the proposed expense for this project is modest.

In reply Guelph Hydro submitted that it is necessary to start educating the public on smart grid technologies to encourage public acceptance of smart grid activities. Guelph Hydro submitted that, considering that the level of funding requested is minimal, the Board may wish to consider expanding its definition of smart grid education and training with approving this pilot project.

BOARD FINDINGS

The Board agrees with the submission of staff that this proposed project is outside of the parameters of a smart grid education and training project as defined in the DSP Filing Requirements. The Board is also not convinced that the merits of the program are such that varying from the DSP Filing Requirements is warranted. Accordingly, the Board will not approve the costs associated with this program.

Smart Grid Demonstration Home

Guelph Hydro requested the following OM&A expenses for a Smart Grid – Smart Home Demonstration Project:

Table 11

	2012 $	2013 $	2014 $	2015 $	Total $
CapEx	0	0	0	0	0
OM&A	45,000	130,000	55,000	10,000	240,000

Guelph Hydro stated that it wishes to leverage the communication capability enabled by the Zigbee chip technology by this project. Guelph Hydro noted that in order for the smart grid to live up to its potential it will be necessary to expand the focus to customers and engage innovative, entrepreneurial companies that know how to create products and services that customer will value. The Smart Home demonstration project's main purpose would be to provide education to a variety of audiences and showcase the following technologies:

- Smart meters;
- Renewable energy;
- In-home display units;
- Home energy management systems;
- Smart appliances – large and small;
- Electric car charging stations;
- Demand management systems; and
- Automated lighting controls.

Guelph Hydro stated that the main purpose of this project is the education of local consumers, although Guelph Hydro acknowledged that this project will be supporting the City of Guelph in hosting the Transatlantic Urban Climate Dialogue workshop/conference in 2012 and 2013.

Board staff agreed with the Applicant that this project will showcase Zigbee-enabled smart grid capabilities. Board staff noted that this project features mainly behind-the-meter technology and its concern as discussed earlier. Nevertheless, Board staff submitted that in the absence of a Board policy on this issue, this project fulfills the requirements of a demonstration project as defined in the DSP Filing Requirements. Board staff noted some overlap with the IHD and the EV Pilot projects, but argued that the monetary implications are immaterial. Board staff submitted that this project is reasonable subject to a later prudence review.

EP and SEC agreed with Board staff and added that any learning gained should be made widely available. EP submitted that Guelph Hydro should seek partners to assist in the funding of the project and that any contributions should be included in a deferral account. SEC added that Guelph Hydro’s high growth location is well suited to such a project. SEC further noted that due to a partnership with a local builder there are no capital costs and that the OM&A budget is fairly modest.

VECC did not oppose the Smart Home demonstration project.

Guelph Hydro did not comment on issues where all parties agreed with Guelph Hydro application and evidence.

BOARD FINDINGS

The Board will not approve the costs associated with this project. A project of this type, which is more of a showcase for emerging technologies, does not meet the criteria set out in the DSP Filing Requirements for a smart grid demonstration project. The Board also notes that the showcased technologies are predominantly behind-the-meter technologies. The Board is of the view that approval of this project would pre-empt the ongoing Renewed Regulatory Framework consultation, as previously discussed.

<u>Additional Technical Staffing Resources</u>

Guelph Hydro originally included the costs of two “Smart Grid” technicians in its OM&A budget under Compensation. Guelph Hydro subsequently proposed to include the cost of these two Smart Grid technicians in the calculation of the GEA funding adder.

Guelph Hydro originally included the following operational expenditures for additional technical staffing resources:

Table 12

	2012 $	2013 $	2014 $	2015 $	Total $
CapEx	0	0	0	0	0
OM&A	174,000	174,000	174,000	174,000	696,000

In response to interrogatories Guelph Hydro provided a detailed allocation of these resources to the Renewable Generation Connection project and the various Smart Grid projects. On December 12, 2011 Guelph Hydro updated the OM&A summary table (see Table 4) to include the proposed allocation of one technical staff person related to the Renewable Generation Connection Project.

Board staff and EP supported the operational expense of one FTE in relation to the Renewable Generation Connection project as proposed by the Applicant, but submitted that a second technical staff, solely responsible for smart grid activities, is excessive based on its positioning on the IHD and Smart Grid High School Education projects.

VECC agreed with Board staff and EP in respect to the reduction of one FTE, but added that it is not necessary to eliminate the IHD project. VECC submitted that the elimination of the EV Pilot project and internal efficiencies are sufficient to justify the reduction of one FTE.

SEC made no submission on this particular issue, but submitted that the Basic GEA Plan should be approved as filed.

BOARD FINDINGS

The Board approves the costs associated with Smart Grid Technician #2, on the basis that this additional resource is intended to primarily support the needs of Renewable Generator Connection Requests. The Board will not approve the costs associated with Smart Grid Technician #1.

IMPLEMENTATION

Guelph Hydro applied for rates effective January 1, 2012. The Settlement Agreement approved by the Board on December 5, 2011 stated that rates would be effective January 1, 2012, but in the event that rates cannot be implemented for the month of January, Guelph Hydro requested that the Board approve a rate rider to recover foregone revenue.

While Guelph Hydro's new rates will be effective January 1, 2012, the Board has determined that the implementation date will be April 1, 2012.

The Board directs Guelph Hydro to true up for the difference between the Board's final rates and interim rates for the months of January, February and March 2012 and derive the associated rate riders, using a 9 month term, to be applied over the April 1 to December 31, 2012 period. Guelph Hydro shall submit as part of its draft Rate Order ("DRO") detailed calculations in a Microsoft Excel format. The Board also directs that the rate riders for the disposition of Group 1 and Group 2 account balances, Account 1521, and LRAM rate riders reflect an April 1, 2012 implementation date.

On December 20, 2011 the Board issued its Rate Order for Hydro One Transmission (EB-2011-0268) which adjusted the UTRs effective January 1, 2012, as shown in the following table:

Table 13

Uniform Transmission Rates	**Jan 1, 2012**
Network Service Rate	$3.57
<u>Connection Service Rates</u>	
Line Connection Service Rate	$0.80
Transformation Connection Service Rate	$1.86

These 2012 UTRs were not incorporated into the module previously filed by Guelph Hydro. The Board directs Guelph Hydro to include in its draft Rate Order, an updated RTSR filing module which includes the UTRs effective January 1, 2012 noted above.

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

The Board notes that the Settlement agreement stated that the parties have agreed that Guelph Hydro may establish a variance account that would track any difference between (a) the amount included in 2012 Test Year OM&A reflecting Guelph Hydro's policy on capitalization of overheads under IFRS and (b) the amounts that may be eligible for inclusion in OM&A under a standardized approach that may be adopted by the Board at a later date, for disposition at a later date. The Board notes that this provision was accepted as part of the settlement agreement. The Board is of the view that it is premature to issue an accounting order to formally establish the account, since it is unknown whether the conditions that could give rise to any potential variances will occur at all. Accordingly, the Board directs Guelph Hydro to request an accounting order to formally establish a variance account at the time potential variances occur and are material.

The Board has made findings in this Decision which change the 2012 revenue requirement and therefore change the distribution rates from those proposed by Guelph Hydro. In filing its draft Rate Order, the Board expects Guelph Hydro to file detailed supporting material, including all relevant calculations showing the impact of the Settlement Agreement and this Decision on Guelph Hydro's revenue requirement, the allocation of the approved revenue requirement to the classes and the determination of the final rates. Supporting documentation shall include, but not be limited to, filing a completed version of the Revenue Requirement Work Form and an updated Smart Meter model, which can be found on the Board's website.

THE BOARD THEREFORE ORDERS THAT:

1. Guelph Hydro shall file with the Board, and shall also forward to intervenors, a draft Rate Order attaching a proposed Tariff of Rates and Charges reflecting the Board's findings in this Decision within **7 days** of the date of the issuance of this Decision. The draft Rate Order shall also include customer rate impacts and detailed supporting information showing the calculation of the final rates including the Revenue Requirement Work Form in Microsoft Excel format.

2. Board staff and intervenors shall file any comments on the draft Rate Order with the Board and forward to Guelph Hydro within **7 days** of the date of filing of the draft Rate Order.

3. Guelph Hydro shall file with the Board and forward to intervenors responses to any comments on its draft Rate Order within **4 days** of the date of receipt of Board staff and intervenor comments.

4. Intervenors shall file with the Board and forward to Guelph Hydro their respective cost claims within **7 days** from the date of issuance of the final Rate Order.

5. Guelph Hydro shall file with the Board and forward to intervenors any objections to the claimed costs within **14 days** from the date of issuance of the final Rate Order.

6. Intervenors shall file with the Board and forward to Guelph Hydro any responses to any objections for cost claims within **21 days** of the date of issuance of the final Rate Order.

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

All filings with the Board must quote the file number EB-2011-0123, and be made through the Board's web portal at www.errr.ontarioenergyboard.ca, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must be received by the Board by 4:45 p.m. on the stated date. Parties should use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available, parties may e-mail their documents to the attention of the Board Secretary at BoardSec@ontarioenergyboard.ca. All other filings not filed via the Board's web portal should be filed in accordance with the Board's *Practice Directions on Cost Awards*.

DATED at Toronto, February 22, 2012

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix A

To Decision and Order

Board File No: EB-2011-0123

DATED: February 22, 2012

Guelph Hydro Electric Systems Inc.
Settlement Agreement

James Sidlofsky
T 416-367-6277
F 416-361-2751
jsidlofsky@blg.com

Borden Ladner Gervais LLP
Scotia Plaza, 40 King Street W
Toronto, ON, Canada M5H 3Y4
T 416.367.6000
F 416.367.6749
blg.com

Borden Ladner Gervais

December 2, 2011

Delivered by Email and Courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, Ontario
M4P 1E4

Dear Ms. Walli:

Re: Guelph Hydro Electric Systems Inc. 2011 Cost of Service Electricity Distribution Rate Application –Board File No. EB-2011-0123

We are counsel to Guelph Hydro Electric Systems Inc. ("Guelph Hydro") in the above captioned matter.

A settlement conference was convened in respect of this proceeding on Tuesday, November 15, 2011. The conference continued into Wednesday, November 16, 2011. We are pleased to advise that the parties have achieved a complete settlement in this matter, leaving outstanding only those issues that the Board determined in Procedural Order No. 2 would not be eligible for settlement (Issues 6.1, 6.2 and 12.1, relating to Smart Meters and Guelph Hydro's Green Energy Act Plan). In accordance with Procedural Orders Nos. 2 and 4, please find accompanying this letter a copy of the proposed Settlement Agreement. Each of the parties has reviewed and approved the Agreement, and the parties respectfully request that the Board approve the Settlement Agreement. The parties to this proceeding acknowledge with thanks the assistance of Mr. Haussmann and Board staff in this process.

Procedural Orders Nos. 2 and 4 set out certain additional steps in this proceeding. These included the filing of any settlement proposal; the commencement of the hearing on the issues identified above and any other unsettled issues on Monday, December 5, 2011, at 10 a.m.; and the filing of written submissions. With the complete settlement of all eligible issues, and subject to the Board's approval of the Settlement Agreement, the hearing will be limited to the issues noted above.

As confirmed in the Settlement Agreement, as part of the settlement, the parties have considered the appropriate effective date for Guelph Hydro's 2012 distribution rates and agree that the effective date of the new rates should be January 1, 2012. The parties agree further that in the event that the Board is not able to issue its final Rate Order in respect of Guelph Hydro's rates in time for implementation as of January 1, 2012, then Guelph Hydro will be permitted to recover the distribution revenue requirement shortfall for any months in the 2012 Rate Year in respect of which the new rates have not been implemented, by way of a rate rider. Guelph Hydro will provide a proposed rider in conjunction with its Draft Rate Order following the Board's Decision.

Should you have any questions or require further information, please do not hesitate to contact me.

Yours very truly,
BORDEN LADNER GERVAIS LLP

Original signed by James C. Sidlofsky

James C. Sidlofsky
JCS

cc:
Birgit Armstrong, Ontario Energy Board
Ian Miles, Guelph Hydro Electric Systems Inc.
Cristina Birceanu, Guelph Hydro Electric Systems Inc.

TOR01: 4789843: v2

Table of Contents

EB-2011-0123

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 Guelph Hydro Electric Systems Inc. for an Order or Orders approving just and reasonable rates and other service charges for electricity distribution to be effective January 1, 2012.

GUELPH HYDRO ELECTRIC SYSTEMS INC. PROPOSED SETTLEMENT AGREEMENT

Filed: December 2, 2011

INTRODUCTION:

Guelph Hydro Electric Systems Inc. ("Guelph Hydro") carries on the business of distributing electricity within the City of Guelph and the Village of Rockwood.

Guelph Hydro filed an application with the Ontario Energy Board (the "Board") on June 30, 2011 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 Guelph Hydro charges for electricity distribution, to be effective January 1, 2012. The Board has assigned the application File Number EB-2011-0123.

Three parties requested and were granted intervenor status: the Energy Probe Research Foundation (Energy Probe), the Vulnerable Energy Consumers' Coalition (VECC), and the School Energy Coalition (SEC).

In Procedural Order No. 1, issued on August 5, 2011, the Board approved the intervenors in this proceeding, set dates for interrogatories and interrogatory responses and made its determination regarding the cost eligibility of intervenors and issued a Draft Issues List for comment. Comments on the Draft Issues List were due August 18, 2011. No parties submitted comments.

On September 15, 2011, Guelph Hydro filed a letter stating that it would not be able to file its interrogatory responses in accordance with the deadline established in Procedural Order No. 1 due to the volume and complexity of the interrogatories received.

On September 20, 2011, the Board granted an extension until September 30, 2011. Guelph Hydro filed partial responses on September 30, 2011. Guelph Hydro filed the remainder of the interrogatory responses on October 11, 2011.

On October 12, 2011, the Board issued Procedural Order No. 2 and determined the next steps in this proceeding. The Procedural Order No. 2 included the Final Issues List.

In its Procedural Order No. 2, the Board considered it appropriate to deem issues pertaining to the Green Energy and Green Economy Act, 2009 ("GEA") Plan ineligible for settlement. The Board has determined Issue 12.1 relating to Guelph Hydro's Green Energy Act Plan, including the Smart Grid component of the plan, as contained in the Final Issues List, is not eligible for settlement. The Board also determined that Issues 6.1 and 6.2 are not eligible for settlement, as the issue of the smart meter deployment beyond minimum functionality relates to Smart Grid development.

In accordance with the Procedural Order No. 2, Guelph Hydro received a list of questions for Technical Conference by October 21, 2011, and responded partial in writing on October 26, 2011. The Technical Conference commenced on October 27, 2011.

As a result of the Technical Conference proceeding, Guelph Hydro responded to 32 undertakings between November 8 and November 14, 2011.

The evidence in this proceeding (referred to here as the "Evidence") consists of the Application including the updates to the Application, and Guelph Hydro's responses to the initial interrogatories, the questions provided to Guelph Hydro prior to and during the Technical Conference, and its responses to Undertakings given during the Technical Conference. The Appendices to this Settlement Agreement (the "Agreement") are also included in the Evidence. The Settlement Conference was duly convened in accordance with the Procedural Order No. 2, with Mr. Chris Haussmann as facilitator. The Settlement Conference commenced on November 15 and concluded on November 16, 2011.

Guelph Hydro and the following Intervenors participated in the Settlement Conference:

Energy Probe Research Foundation (Energy Probe)
School Energy Coalition (SEC)
Vulnerable Energy Consumers Coalition (VECC).

Guelph Hydro and the intervenors are collectively referred to below as the "Parties".

These settlement proceedings are subject to the rules relating to confidentiality and privilege contained in the Board's *Settlement Conference Guidelines* (the "Guidelines"). The Parties understand this to mean that the documents and other information provided, the discussion of each issue, the offers and counter-offers, and the negotiations leading to the settlement – or not – of each issue during the Settlement Conference are strictly confidential and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception: the need to resolve a subsequent dispute over the interpretation of any provision of this Settlement Agreement.

The role adopted by Board Staff in the Settlement Conference is set out in page 5 of the Guidelines. Although Board staff is not a party to this Agreement, as noted in the Guidelines, Board OEB staff who did participate in the Settlement Conference are bound by the same confidentiality standards that apply to the Parties to the proceeding.

A COMPLETE SETTLEMENT ON THE ISSUES ELIGIBLE FOR SETTLEMENT HAS BEEN REACHED IN THIS PROCEEDING:

The Parties are pleased to advise the Board that a complete settlement has been reached on the issues in the proceeding that are eligible for settlement. In accordance with the Board's Procedural Order No. 2, the remaining issues designated for Oral Hearing on December 5, 2011 are related to Issues 12.1 (Green Energy Act Plan), and to Issues 6.1 and 6.2 (Smart Meter Deployment). For convenience and in order to serve all Parties, Guelph Hydro has included in the Agreement its Capitalization Policy (please see Attachment 1 – Capitalization Policy).

This document comprises the Proposed Settlement Agreement to the Board, and it is presented jointly by Guelph Hydro and Energy Probe, SEC and VECC. It identifies the settled matters, and contains such references to the Evidence as is necessary to assist the Board in understanding the Agreement. The Parties confirm that the Evidence filed to date in respect of each settled issue, as supplemented in some instances by additional information recorded in this Agreement, supports the settlement of the matters identified in this Agreement. In addition, the Parties agree that the Evidence, supplemented where necessary by the additional information appended to this Agreement, contains sufficient detail, rationale and quality of information to allow the Board to make findings in keeping with the settlement reached by the Parties.

The Parties explicitly request that the Board consider and accept this Settlement Agreement as a package. None of the matters in respect of which a settlement has been reached is severable. Numerous compromises were made by the Parties with respect to various matters to arrive at this comprehensive Agreement. The distinct issues addressed in this proposal are intricately interrelated, and reductions or increases to the agreed-upon amounts may have financial consequences in other areas of this proposal which may be unacceptable to one or more of the Parties. If the Board does not accept the Agreement in its entirety, then there is no Agreement unless the Parties agree that those portions of the Agreement that the Board does accept may continue as a valid settlement.

It is further acknowledged and agreed that none of the Parties will withdraw from this Agreement under any circumstances, except as provided under Rule 32.05 of the *Board's Rules of Practice and Procedure*.

It is also agreed that this Agreement is without prejudice to any of the Parties re-examining these issues in any subsequent proceeding and taking positions inconsistent with the resolution of these issues in this Agreement. However, none of the Parties will, in any subsequent proceeding, take the position that the resolution therein of any issue settled in this Agreement, if contrary to the terms of this Agreement, should be applicable for all or any part of the 2012 Test Year.

References to the Evidence supporting this Agreement on each issue are set out in each section of the Agreement. The Appendices and Attachments to the Agreement provide further evidentiary support. The Parties agree that this Agreement and the Appendices form part of the record in EB-2011-0123. The Appendices were prepared by the Applicant. The Intervenors are relying on the accuracy and completeness of the Appendixes and Attachments in entering into this Agreement.

The Parties believe that the Agreement represents a balanced proposal that protects the interests of Guelph Hydro's customers, employees and shareholder and promotes economic efficiency and cost effectiveness. It also provides the resources which will allow Guelph Hydro to manage its assets so that the highest standards of performance levels are achieved and customers' expectations for the safe and reliable delivery of electricity at reasonable prices are met.

The Parties have agreed that the effective date of the rates resulting from this proposed agreement is January 1, 2012. In the event that the Board does not issue its Final Rate Order in time for Guelph Hydro to implement the rates resulting from this Agreement as of January 1, 2012, the Parties agree that Guelph Hydro may establish a rate rider that would allow it to recover that portion of the Revenue Deficiency that would have been recovered between

January 1, 2012 and the Board-Approved Effective Date.

ORGANIZATION AND SUMMARY OF THE SETTLEEMENT AGREEMENT:

For the purpose of organizing this Agreement, the Parties have followed the approved Issues List.

The following Appendices accompany this Settlement Agreement:

- Appendix A – Summary of the Significant Items Adjusted as a result of this Agreement
- Appendix B – Updated Fixed Asset & Depreciation Expense Continuity Schedules
- Appendix C – Updated Cost of Power
- Appendix D – 2012 Test Year Updated Load Forecast
- Appendix E – 2012 Test Year Updated Other Revenue
- Appendix F – 2012 Test Year Updated OM&A Expense
- Appendix G – 2012 Test Year Updated PILs
- Appendix H – 2012 Test Year Updated Cost of Capital
- Appendix I – 2012 Test Year Updated Revenue Deficiency
- Appendix J – 2012 Test Year Updated Revenue to Cost Ratios
- Appendix K – Summary of Updated Customer Impacts
- Attachment 1 – Capitalization Policy
    - PP&E Deferral Account
    - CGAAP vs. IFRS Comparison of Burdenable Items
- Attachment 2 – Cost Allocation Sheets O1 and O2
- Attachment 3 – Revenue Requirement Work Form

UNSETTLED MATTERS:

All matters that are eligible for settlement in this proceeding have been settled. The following issues are ineligible for settlement and will be the subject of an oral hearing scheduled to begin December 5, 2011.

6. Smart Meters

6.1 Is the proposed inclusion of the smart meter costs in the 2012 revenue requirement appropriate?

6.2 Is the proposed disposition of the balances in variance accounts 1555 and 1556 appropriate?

12. Green Energy Act Plan

12.1 Is Guelph Hydro's Green Energy Act Plan, including the Smart Grid component of the plan appropriate?

OVERVIEW OF THE SETTLED MATTERS:

This Agreement will allow Guelph Hydro to continue to make the necessary investments in maintenance and operation expenditures as well as capital investments to maintain the safety and reliability of the electricity distribution service that it provides.

This Agreement will also allow Guelph Hydro to: maintain current capital investment levels in infrastructure to ensure a reliable distribution system; manage current and future staffing levels, skills and training to ensure regulatory compliance with Codes and Regulations; promote conservation programs including the Ministry of Energy directives as a condition of Guelph Hydro's distribution licence; and continue to provide the high level of customer service that Guelph Hydro's customers have come to expect.

The Parties agree that no rate classes face bill impacts in this proceeding that require mitigation efforts.

The revised Service Revenue Requirement for the 2012 Test Year is $28,590,938 . This revenue requirement has been adjusted based on the updated cost of capital parameters (ROE and Deemed ST Debt rate) issued by the Board on November 10, 2012. The Long Term debt rate was agreed to be 5.264% based on the fact that Guelph Hydro's long term debt with an interest rate of 5.264% is held by external financial institutions (Senior Unsecured Debentures - maturity date Dec. 6, 2030). This represents a revenue deficiency, based on forecast 2012 revenue at current rates, of $1,619,982 . The revised revenue deficiency of $1,619,982 is ($4,324,135) lower, or 72.75% lower than the revenue deficiency of $5,944,117 set out in Guelph Hydro's pre-filed evidence. An amount of $141,287 of the reduction is attributable to the updated cost of capital parameters. The changes are detailed in the table below.

	Original As per Application (A)	Settlement Submission (B)	Difference (C = B - A)
Service Revenue Requirement	$32,703,106	$28,590,938	($4,112,168)
Revenue Offset	$2,050,989	$2,207,000	$156,011
Base Revenue Requirement	$30,652,117	$26,383,938	($4,268,179)
Revenue at Existing Rates	$24,708,000	$24,763,956	$55,956
Revenue Deficiency	$5,944,117	$1,619,982	($4,324,135)

Through the settlement process, Guelph Hydro has agreed to certain adjustments from its original 2012 Application and subsequent updated Evidence. The changes are described in the following sections.

1. GENERAL

1.1 Has Guelph Hydro responded appropriately to all relevant Board directions from previous proceedings?

Status: **Complete Settlement**

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence: Interrogatory responses Board Staff IRR # 3,4
Interrogatory responses VECC IRR # 1

For the purposes of settlement the Parties accept the evidence of the Applicant that there were no outstanding obligations or orders from previous Board decisions.

1.2 Are Guelph Hydro's economic and business planning assumptions for 2012 appropriate?

Status: **Complete Settlement**

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence: Interrogatory responses Board Staff TCQ #2
Interrogatory responses VECC TCQ#1, 2

For the purposes of settlement, the Parties accept Guelph Hydro's economic and business planning assumptions for 2012.

1.3 Is service quality, based on the Board specified performance assumptions for 2012 appropriate?

Status: Complete Settlement

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence: Guelph Hydro's Application – E2,T4,S8,p.1 to 9, and E2,T4,S5,App.C – Asset Management Plan

For the purposes of settlement, the Parties accept Guelph Hydro's evidence with respect to the acceptability of its service quality, based on the Board specified indicators.

1.4 Is the proposal to align the rate year with Guelph Hydro's fiscal year, and for rates effective January 1, 2012 appropriate?

Status: **Complete Settlement**

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence: Guelph Hydro's Application- E1/T1, S2, App. A – Alignment of Rate Year with Fiscal Year Analysis

For the purposes of settlement, the Parties have agreed that Guelph Hydro's proposal to align the rate year with its next fiscal year, which starts January 1, 2012, is appropriate. Further, the Parties agree that Guelph Hydro's 2012 rates should be effective January 1, 2012, and if it is not possible to implement the Board's decision in time for that date, any deficiency that arises between January 1, 2012 and the date of implementation should be collected by the Applicant using a rate rider over the remainder of the Test Year.

2. RATE BASE

2.1 Is the proposed rate base for the test year appropriate?

Status: **Complete Settlement**

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence: Interrogatory responses Board Staff IRR # 5, 6, 7, TCQ # 5

Interrogatory responses Energy Probe IRR # 1, 3, 2,, TCQ # 16, JTC # 1.26

Interrogatory responses VECC IRR # 3, TCQ # 1

Interrogatory responses SEC TCQ # 3

For the purposes of settlement, the Parties have agreed that Guelph Hydro's Rate Base should be $140,198,573 for the 2012 Test Year. A full calculation of this agreed Rate Base is set out later in this section in the table titled "Rate Base".

The agreed Rate Base includes the New MTS (Arlen MTS) expenditures as reflected in the evidence submitted during the Application proceedings. The revised Rate Base value reflects the following adjustments:

- The Parties agree to adjust the 2011 Bridge Year and the 2012 Test Year CAPEX by the HST-PST incremental ITC amount. To implement this adjustment, Guelph Hydro has reduced the 2011 Fixed Asset continuity schedule by $260,320 and the 2012 Accumulated Depreciation by $6,508, and 2012 Fixed Assets by $226,700 and the 2012 Accumulated Depreciation by $2,834.
- The Parties agree to update the Cost of Power (COP) with a weighted wholesale market price of $31.38/MWh , RPP price of $75.15/MWh, and Global Adjustment rate of $40.08/MWh (please see the table below and the COP calculation detailed in Appendix C); it was also agreed to update the Load Forecast as responded to Energy Probe TCQ#14 and increase the forecast 2012 wholesale purchases by 5 MWh, including the impact of 2 MWh for the leap year.

Forecast Monthly Wholesale Electricity Price	
1-Jan-11	38.15
1-Feb-11	32.63
1-Mar-11	32.63
1-Apr-11	32.63
1-May-11	27.22
1-Jun-11	27.22
1-Jul-11	27.22
1-Aug-11	29.34
1-Sep-11	29.34
1-Oct-11	29.34
1-Nov-11	35.39
1-Dec-11	35.39
	$31.38

	OEB RPP Price Report	Energy Probe - RPP Forecast
Forecast Wholesale Electricity Price	$31.83	31.38
Load-Weighted Price for RPP Consumers	$34.62	$34.13
Impact of the Global Adjustment	$40.08	$40.08
Adjustment to Address Bias Towards Unfavorable Variance ($/MWh)	$1.00	$1.00
Adjustment to Clear Existing Variance ($/MWh)	($0.06)	($0.06)
Average Supply Cost for RPP Consumers ($/MWh)	$75.64	$75.15

- Guelph Hydro has updated the 2012 Load Forecast to 1,698 GWh and the Cost of Power to $153,524,605 .

Agreed-upon adjustments to Guelph Hydro's proposed Rate Base are set out in the following table:

RATE BASE

Particulars	Initial Application	Adjustments	Settlement Agreement
Gross Fixed Assets (average)	$178,018,480	($373,670)	$177,644,810
Accumulated Depreciation (average)	($63,313,009)	$689,182	($62,623,827)
Net Fixed Assets (average)	$114,705,471	$315,512	$115,020,983
Allowance for Working Capital	$23,838,540	$1,339,051	$25,177,591
Total Rate Base	$138,544,011	$1,654,562	$140,198,573

2.2 Is the working capital allowance for the test year appropriate?

Status: **Complete Settlement**

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence: Interrogatory responses Energy Probe IRR # 4, 5, 6, 7, 8, TCQ # 1

Interrogatory responses VECC IRR # 4

For the purposes of settlement, the Parties agree to the following Working Capital Allowance calculated based on 15 % of the Controllable Expenses of $14,326,000 and COP of 153,524,605

ALLOWANCE FOR WORKING CAPITAL

Particulars	Initial Application	Adjustments	Settlement Agreement
Controllable Expenses	$15,611,241	($1,285,241)	$14,326,000
Cost of Power	$143,312,358	$10,212,247	$153,524,605
Working Capital Base	$158,923,599	$8,927,006	$167,850,605
Working Capital Rate %	15.00%	0.00%	15.00%
Working Capital Allowance	$23,838,540	$1,339,051	$25,177,591

2.3 Is the capital expenditure forecast for the test year appropriate?

Status: Complete Settlement

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence: Interrogatory responses Board Staff IRR # 8, 10, 11, 12, 13, 14, 9, TCQ # 6, 7
Interrogatory responses Energy Probe TCQ # 2, 17
Interrogatory responses SEC IRR # 6, 7, 8, 9, 10, TCQ # 4, 5

- For the purposes of settlement, the Parties agree to adjust the 2011 Bridge Year and the 2012 Test Year CAPEX by the HST-PST incremental ITC amount.
  - Guelph Hydro has reduced the 2011 Fixed Asset continuity schedule by $260,320 and the Accumulated Depreciation by $6,508, and 2012 Fixed Assets by $226,700 and the 2012 Accumulated Depreciation by $2,834.

As noted in Issue 2.4 below, the Parties have agreed that Guelph Hydro's capitalization policy under IFRS, as set out in Attachment 1 to this Settlement Agreement, is appropriate for the purposes of establishing Guelph Hydro's revenue requirement and rates for the 2012 Test Year; that Guelph Hydro will provide the information set out in Attachment 1- Appendix 2; and that Guelph Hydro may establish a variance account that would track any difference between (a) the amounts included in 2012 Test Year OM&A reflecting Guelph Hydro's policy on capitalization of overheads under IFRS, and (b) the amounts that may be eligible for inclusion in OM&A under a standardized approach that may be adopted by the Board in future, for disposition at a later date.

2.4 Is the capitalization policy and allocation procedure appropriate?

Status: **Complete Settlement**

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence: Interrogatory responses SEC IRR # 11

For the purpose of obtaining complete settlement of all issues, the Parties have agreed that Guelph Hydro’s capitalization policy under IFRS, as set out in Attachment 1 to this Settlement Agreement, is appropriate for the purposes of establishing Guelph Hydro’s revenue requirement and rates for the 2012 Test Year.

The Parties have also agreed that Guelph Hydro will provide information on the record of this proceeding in the form shown in Attachment 1 Appendix 2, indicating changes in Guelph Hydro’s capitalization of various categories of expenses as between CGAAP and IFRS. The table is similar to that produced by Hydro Ottawa Limited in its response to Oral Hearing Undertaking No. L2.8 in its 2012 cost of service distribution rate application (EB-2011-0054). The Intervenors have requested this information in this proceeding, and intend to make the same request in other 2012 cost of service proceedings, with the intention of approaching the Board at a later date with a request that the Board develop a standardized approach to the capitalization of overheads. In order to ensure that Guelph Hydro and its customers are kept whole in the event that the Board adopts a standardized approach, the Parties have agreed that Guelph Hydro may establish a variance account that would track any difference between (a) the amounts included in 2012 Test Year OM&A reflecting Guelph Hydro’s policy on capitalization of overheads under IFRS, and (b) the amounts that may be eligible for inclusion in OM&A under a standardized approach that may be adopted by the Board at a later date, for disposition at a later date.

With respect to depreciation, the Parties have agreed that for ratemaking purposes Guelph Hydro will use the “typical” useful lives developed by Kinectrics Inc. in the March 24, 2010 *Useful Life* *of Assets* study included in the Application at Exhibit 4, Tab 2, Schedule 10, Appendix A.

3. LOAD FORECAST AND OPERATING REVENUE

3.1 Is the load forecast methodology including weather normalization appropriate?

Status: **Complete Settlement**

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence: Interrogatory responses Board Staff IRR # 15, 16, TCQ # 8
Interrogatory responses Energy Probe IRR # 9, TCQ # 3, 14, 18
Interrogatory responses VECC IRR # 5, 6, 7, 8, 9, TCQ # 2, 3, 4, 5, 6, 7

For the purposes of settlement, the Parties agree that the Load Forecast version presented by Guelph Hydro in response to Energy Probe TCQ#14 is appropriate.

The results of Guelph Hydro's Load Forecast are as follows:

Predicted Purchases

Year	GWh
2011	1,682
2012	1,698

Predicted sales

Year	GWh
2011	1,660
2012	1,676

3.2 Are the proposed customers/connections and load forecasts (both kWh and kW) for the test year appropriate?

Status: Complete Settlement

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence:

Interrogatory responses Energy Probe IRR # 10, 11, 12, 13, 14, 15 TCQ # 4 TCQ #14, JTC # 1.23

Interrogatory responses VECC IRR # 10

For the purposes of settlement, the Parties agree with Guelph Hydro’s proposed customers/connections and load forecasts (both kWh and kW) for the 2012 test year as the result of the Load Forecast presented in Guelph Hydro’s response to Energy Probe TCQ#14.

3.3 Is the impact of CDM appropriately reflected in the load forecast?

Status: **Complete Settlement**

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence: Interrogatory responses Board Staff IRR # 17

Interrogatory responses Energy Probe IRR # 16, TCQ # 3

Interrogatory responses VECC IRR # 11, 12

For the purposes of settlement, the Parties agree that the CDM adjustments as presented in the Application are appropriate. The CDM adjustments are presented in the following table, for the Board's assistance:

CDM Targets/Adjustments	2011	2012
kW	1,671	3,342
kWh	7,953,000	15,906,000

3.4 Is the proposed forecast of test year throughput revenue appropriate?

Status: **Complete Settlement**

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence: Interrogatory responses VECC IRR # 13, 14

For the purposes of settlement, the Parties agree on the following throughput revenue:

Service Revenue Requirement	$28,590,938
Less: Revenue Offsets	$2,207,000
Total Base Revenue Requirement	$26,383,938

3.5 Is the test year forecast of other revenues appropriate?

Status: **Complete Settlement**

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence:

Interrogatory responses Board Staff IRR # 18, 19, 20, TCQ # 9, 10, JTC # 1.4, 1.5

Interrogatory responses Energy Probe IRR # 18, 17,TCQ # 5, 19, JTC # 1.20

Interrogatory responses VECC IRR # 15, 16, 17, TCQ # 8, 9, JTC 1.18

For the purposes of settlement, the Applicant agrees to increase the forecast of Other Distribution Revenue for 2012 test year to equal the 2010 Other Revenue amount of $2,207,000.

4. OPERATING COSTS

4.1 Is the overall OM&A forecast for the test year appropriate?

Status: **Complete Settlement**

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence:

Interrogatory responses Board Staff IRR # 21, 22, 23, TCQ # 11, JTC # 1.17

Interrogatory responses Energy Probe IRR # 19, 20, 21, 22, 24, 26, 27, 23 and 25, TCQ # 6, 22, JTC # 1.21, 1.22

Interrogatory responses VECC IRR # 18, 20, 21, 19,

Interrogatory responses SEC IRR #12, 13, 14, 15, 16, 17, TCQ # 6, 7

For the purposes of settlement, the Parties agree that the 2012 OM&A for the test year should be \$14,326,000. The Parties accept the Applicant's assertion that it can safely and reliably operate the company based on the total OM&A budget proposed. The Parties have agreed that the adjustment will be based on an "envelope" approach, so that any determination of potential budget reductions to reflect the Board-approved 2012 OM&A will be at the discretion of Guelph Hydro. For the Board's information, though, Guelph Hydro is currently considering adjusting its OM&A budget for 2012 by reducing the administrative portion in the areas of communications (\$150,000), meter reading expenses (\$110,000), and other outside contracted services and professional fees (\$223,000).

As noted in Issue 2.3 above, the Parties have agreed that Guelph Hydro's capitalization policy under IFRS, as set out in Attachment 1 to this Settlement Agreement, is appropriate for the purposes of establishing Guelph Hydro's revenue requirement and rates for the 2012 Test Year; that Guelph Hydro will provide the information set out in Attachment 1 Appendix **2**; and that Guelph Hydro may establish a variance account that would track any difference between (a) the amounts included in 2012 Test Year OM&A reflecting Guelph Hydro's policy on capitalization of overheads under IFRS, and (b) the amounts that may be eligible for inclusion in OM&A under a standardized approach that may be adopted by the Board at a later date, for disposition at a later date.

4.2 Are the methodologies used to allocate shared services and other costs appropriate?

Status: **Complete Settlement**

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence: Interrogatory responses Board Staff TCQ # 12

Interrogatory responses Energy Probe IRR # 28

Interrogatory responses SEC IRR #18, 20, 21, 22, 23, 24, TCQ # 8, IRR # 19, 25, 26,27

For the purposes of settlement, the Parties accept the methodology used by Guelph Hydro to allocate shared services and other costs.

4.3 Is the proposed level of depreciation/amortization expense for the test year appropriate?

Status: Complete Settlement

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence: Interrogatory responses Board Staff IRR # 24, 25
Interrogatory responses Energy Probe IRR # 29, TCQ # 7, 8, 20, 21, IRR # 30, 31
Interrogatory responses SEC TCQ # 9, 10, JTC 1.27, IRR # 28, 29, 30

As noted above, for the purposes of settlement, the Parties have agreed to use the "typical" useful lives developed by Kinectrics Inc. in the March 24, 2010 *Useful Life of assets study* included in the Application at Exhibit 4, Tab 2, Schedule 10, Appendix A. The result is a reduction of 2012 depreciation by $434,339. A revised Fixed Asset Continuity Schedule for each of 2010, 2011 and 2012 is annexed as Appendix B. This also causes an increase in the amount in the PP&E Deferral Account. This adjustment is set forth under Issue 11.1 below.

4.4 Are the 2012 compensation costs and employee levels appropriate?

Status: Complete Settlement

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence:

Interrogatory responses Board Staff IRR # 26, 27, 28, 29, TCQ # 13, 14, JTC # 10

Interrogatory responses Energy Probe IRR # 32, TCQ # 9

Interrogatory responses VECC IRR # 22, 23, 24

Interrogatory responses SEC IRR # 32, 33, 34, 35, 37, 38, 39, 40, 41, 42, 43, 44, 45, TCQ # 11, 12, 13, 14, 15, 16, JTC # 1.28, IRR # 31, 36

- For the purposes of settlement, the Parties have agreed that the Post Retirement Actuarial Gain of $2.292,251 is to be disposed of through a rate rider over the average remaining service life of the employees covered. In the most recent Actuarial Study (Exhibit 4, Tab 2, Schedule 7, Appendix A) that service life is estimated at 13 years. The calculation of the resulting rate rider is set forth below.

			2010 RRR number of customers and revenues						
Rate Class	Fixed Metric		Year end Customers or Connections	Allocator = Distribution Revenue Account (4080)	Revenues	Years of Disposition	Post Retirement Actuarial Gain (PRAG) Amount	PRAG Rate Riders	
					%	13	-$2,292,251.00	Metric	$/month
			A	B	C	Y	D= CxB	F=(D/A)x1/12/Y	
Residential	Customer		46,001	$13,197,037.00	55.50%		-$1,272,294.00		-$0.18
General Service Less Than 50 kW	Customer		3,647	$2,947,049.00	12.39%		-$284,117.77		-$0.50
General Service 50 to 999 kW	Customer		557	$3,420,598.19	14.39%		-$329,771.49		-$3.80
General Service 1,000 to 4,999 kW	Customer		41	$3,073,360.81	12.93%		-$296,295.19		-$46.33
Large Use	Customer		4	$978,521.01	4.12%		-$94,336.81		-$151.18
Unmetered Scattered Load	Connection		578	$47,549.54	0.20%		-$4,584.13		-$0.05
Sentinel Lighting	Connection		25	$4,356.87	0.02%		-$420.04		-$0.11
Street Lighting	Connection		13,035	$108,202.75	0.46%		-$10,431.56		-$0.01
Total			**63,888**	**$23,776,675.17**	**100.00%**		**-$2,292,251.00**		

- The parties agree to increase benefits expense by $87,250 reflecting the impact of OMERS contribution rate increases for members and employers for the years 2012 and 2013.

4.5 Is the test year forecast of property taxes appropriate?

Status: Complete Settlement

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence:

Interrogatory responses Board Staff IRR # 30, 31

Interrogatory responses Energy Probe IRR # 33, 34, TCQ # 1.10

Interrogatory responses SEC IRR # 46

Guelph Hydro has forecasted an amount of $432,893 property taxes included in account 5665 – Miscellaneous Expenses (please see Guelph Hydro's response Board Staff IRR#31) that will be payable in 2012 Test Year.

For the purposes of settlement, the Parties have accepted Guelph Hydro's test year forecast of property taxes.

4.6 Is the test year forecast of PILs appropriate?

Status: **Complete Settlement**

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence:

Interrogatory responses Board Staff IRR # 32, TCQ # 15, JTC # 1.2, IRR # 33

Interrogatory responses Energy Probe IRR # 36, 37, 38, 39, TCQ # 11, 21, IRR # 35

For the purpose of settlement, the parties accept Guelph Hydro's 2012 Test Year PILs forecast as set out in Appendix G to this Settlement Agreement. The adjusted PILs calculation incorporates the following adjustments:

- The Applicant agrees to reduce the 2012 PILs amount for federal and provincial apprenticeship; provincial co-op education and federal and provincial small business tax credits by $75,000 and, $53,750 respectively, and Guelph Hydro has implemented this change as follows:
    - Guelph Hydro has adjusted the 2012 PILs downwards by $128,750. In order to reflect the change, the resulted tax rate is 9.52% (please see the Revenue requirement Work Form-Sheet "6.Tax_PIls" – cell O39.
- The Parties agree to increase the CCA balances for the 2012 Test Year by $748,000 to reflect the impact of using actual 2010 UCC ending balances vs. estimated 2010 UCC ending balances in the calculation of revenue requirement.

5. CAPITAL STRUCTURE AND COST OF CAPITAL

5.1 Is the proposed capital structure, rate of return on equity and short term debt rate appropriate?

Status: **Complete Settlement**

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence: Interrogatory responses Board Staff IRR # 34, 35

For the purposes of settlement, the Parties have agreed on the following capital structure, and cost of capital parameters:

2012

Description	Deemed Portion	Effective Rate
Long-Term Debt	56.00%	5.26%
Short-term Debt	4.00%	2.08%
Return On Equity	40.00%	9.42%
Weighted Debt Rate		5.05%
Regulated Rate of Return		6.80%

The above rates are agreed based on (Exhibit 5, Tab 1, Schedule 3, Appendix A) for long term debt, and the Board's most up to date Cost of Capital Parameters updated for Cost of Service Applications effective January 1, 2012, issued by the Board on November 10, 2011, in respect of return on equity ("ROE") and the short term debt rate set by the Board. Accordingly, the Parties have accepted, for the purposes of settlement, a return on equity of 9.42% and a short term debt rate of 2.08% for ratemaking purposes.

5.2 Is the proposed long term debt rate appropriate?

Status: Complete Settlement

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence:

Interrogatory responses Board Staff IRR # 36

Interrogatory responses EP IRR # 40, TCQ # 12

Interrogatory responses SEC IRR # 47

See issue 5.1.6. SMART METERS

6.1 Is the proposed inclusion of the smart meter costs in the 2012 revenue requirement appropriate?

Status: No Settlement (left for the Oral Hearing according to OEB PO No.2)

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence:

Interrogatory responses Board Staff IRR # 37, 39, 40, 41, 42, 43, 44, 45, TCQ # 16

Interrogatory responses Energy Probe TCQ # 21

Interrogatory responses VECC IRR # 25, 26, TCQ # 10

Interrogatory responses SEC IRR # 48

According to the Board’s Procedural Order No. 2, the issue is not eligible for settlement.

This issue is designated to an oral hearing that will commence on December 5, 2011.

The proposed 2012 revenue requirement related to smart meter costs is of $1.61M, as Guelph Hydro presented as evidence and filled on November 23, 2011.

The Parties have assumed this amount as a placeholder in agreeing to all totals in this Agreement, with the understanding that any adjustments to this amount by the Board will either be captured in a variance account, or will be direct adjustments to the revenue requirement and other totals included in this Agreement.

6.2 Is the proposed disposition of the balances in variance accounts 1555 and 1556 appropriate?

Status: No Settlement (left for the Oral Hearing according to OEB PO No.2)

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence:

Interrogatory responses Board Staff IRR # 46, TCQ # 17, 18, 19, JTC # 32

Interrogatory responses Energy Probe IRR # 41, TCQ # 13, JTC # 1.19

According to the Board's Procedural Order No. 2, the issue is not eligible for settlement. This issue is deferred to an oral hearing that will commence on December 5, 2011.

6.3 Is the proposal related to stranded meters appropriate?

Status: Complete Settlement

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence:

Interrogatory responses Board Staff TCQ # 20

Interrogatory responses Energy Probe IRR # 42

For the purposes of settlement, the Parties accept the stranded meter cost recovery of $2,061,500 as presented in the Application and the consequent updates.

7. COST ALLOCATION

7.1 Is Guelph Hydro's cost allocation appropriate?

Status: **Complete Settlement**

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence:

Interrogatory responses Board Staff IRR # 47, 48, 49, 50, 51, 52, 53, 54, 55, TCQ # 21, JTC # 3

Interrogatory responses Energy Probe IRR # 43

Interrogatory responses VECC IRR # 27, 28, 29, TCQ # 11, 12, 13, 14

For the purposes of settlement, the Parties accept Guelph Hydro's Cost Allocation (please see Attachment 2), as updated based on the OEB's new Cost Allocation model released August, 2011.

7.2 Are the proposed revenue to cost ratios for each class appropriate?

Status: **Complete Settlement**

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence:

Interrogatory responses Board Staff IRR # 56, TCQ # 22, JTC # 6

Interrogatory responses Energy Probe IRR # 44

Interrogatory responses VECC IRR # 30, TCQ # 15

For the purposes of settlement, the Parties have agreed on the following adjusted revenue to cost ratios:

Cost Allocation Based Calculations

Rate Classification	Revenue to Cost Ratios Per C.A. Study	Rev Requirement by Rate Class @ 100% Rev Cost Ratio	Proposed Revenue to Cost Ratios	Board Target Low	Board Target High	Proposed Rev Requirement by Rate Class @ proposed revenue to cost ratios	Miscellaneous Revenue	2012 Serv Rev Requirement Excl Transformer Allowance and Miscellaneuos Revenue	Proposed Proportion of Distribution Revenue @ 2012 proposed rates
Residential	97.86%	$16,627,422	97.86%	85%	115%	$16,272,421	$1,449,059	$14,823,363	56.18%
GS < 50 kW	136.62%	$2,389,930	120.00%	80%	120%	$2,867,916	$198,430	$2,669,487	10.12%
GS 50 to 999 kW	150.08%	$3,131,268	120.00%	80%	120%	$3,757,521	$184,878	$3,572,643	13.54%
GS > 1000 kW	57.57%	$4,810,371	83.04%	80%	120%	$3,994,686	$280,799	$3,713,887	14.08%
Large Use	111.58%	$1,102,435	111.58%	85%	115%	$1,230,051	$46,249	$1,183,802	4.49%
Sentinel Lights	104.04%	$4,281	104.04%	80%	120%	$4,454	$375	$4,079	0.02%
Street Lighting	56.32%	$426,581	83.04%	70%	120%	$354,211	$37,748	$316,463	1.20%
USL	111.18%	$98,649	111.18%	80%	120%	$109,676	$9,461	$100,215	0.38%
TOTAL		**$28,590,938**				**$28,590,938**	**$2,207,000**	**$26,383,938**	**100.00%**

8. RATE DESIGN

8.1 Are the fixed to variable splits for each class appropriate?

Status: **Complete Settlement**

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence:

Interrogatory responses Board Staff IRR # 57, 58, 59, 60, 61

Interrogatory responses VECC IRR # 31, 32

For the purposes of settlement, the Parties have agreed that the fixed to variable splits as corrected and presented by Guelph Hydro in its response to VECC IRR # 31a are appropriate.

Fixed Charge Analysis

Customer Class	Current Volumetric Charge Split	Current Fixed Charge Spilt	Total	Fixed Rate Based on Current Fixed/Variable Revenue Proportions	2011 Rates From OEB Approved Tariff	Minimum System with PLCC Adustment
Residential	44.66%	55.34%	100.00%	14.29	13.41	16.65
GS < 50 kW	80.64%	19.36%	100.00%	15.00	12.26	23.24
GS 50 to 999 kW	68.03%	31.97%	100.00%	167.22	230.69	123.88
GS > 1000 kW	86.11%	13.89%	100.00%	620.07	620.07	183.07
Large Use	96.08%	3.92%	100.00%	907.62	907.62	505.54
Sentinel Lights	47.27%	52.73%	100.00%	6.96	6.53	8.63
Street Lighting	80.24%	19.76%	100.00%	0.38	0.23	6.05
USL	59.25%	40.75%	100.00%	5.84	5.48	9.05

The Parties agreed to the following Fixed Monthly Charges:

Summary

	1	2	3	4	5	6	7	8
	Residential	General Service Less than 50 kW	General Service 50 to 999 kW	General Service Greater 1,000 to 4,999 kW	Large Use	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
Customer Unit Cost per month - Avoided Cost	$5.68	$12.71	$71.98	$107.39	$303.35	$0.01	$0.52	$1.84
Customer Unit Cost per month - Directly Related	$8.13	$17.62	$105.54	$162.61	$458.54	$0.01	$0.88	$3.08
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$16.65	$23.24	$123.88	$183.07	$505.54	$6.05	$8.63	$9.05
Fixed Charge per approved 2011 IRM	$13.41	$12.26	$230.69	$620.07	$907.62	$0.23	$6.53	$5.48
Resulted from Fixed/Variable split at existing rates	$14.29	$15.00	$167.22	$620.07	$907.62	$0.38	$6.96	$5.84
Proposed Monthly 2012 Fixed Charges	**14.29**	**15.00**	**194.50**	**620.07**	**907.62**	**0.38**	**6.96**	**5.84**

8.2 Are the proposed retail transmission service rates appropriate (RTSR)?

Status: **Complete Settlement**

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence: Interrogatory responses VECC IRR # 33, 34, TCQ # 16

For the purposes of settlement, the Parties have agreed to eliminate the RTSR trend adjustments used by Guelph Hydro. The resulting proposed RTSRs are as follows:

Customer Class		Existing 2011 Rates	RTSR calcualted with OEB Model	Adjustments calculated based on 2012 RTSR_Adjustment_workform OEB Model		2012 Proposed Rates
Residential		A	B	C=B/A-1		
Retail Transmission Rate - Network Service Rate	$/kWh	$0.0062	$0.0064	3.23%		$0.0064
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	$0.0052	$0.0053	1.92%		$0.0053
General Service Less Than 50 kW						
Retail Transmission Rate - Network Service Rate	$/kWh	$0.0057	$0.0059	3.51%		$0.0059
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	$0.0046	$0.0047	2.17%		$0.0047
General Service 50 to 999 kW						
Retail Transmission Rate - Network Service Rate	$/kW	$2.3557	$2.4425	3.68%		$2.4425
Retail Transmission Rate - Network Service Rate - Interval metered	$/kW	$2.4435	$2.5335	3.68%		$2.5335
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	$1.9218	$1.9624	2.11%		$1.9624
Retail Transmission Rate - Line and Transformation Connection Service Rate- Interval Metered	$/kW	$1.9938	$2.0359	2.11%		$2.0359
General service 1,000 to 4,999 kW						
Retail Transmission Rate - Network Service Rate - Interval metered	$/kW	$2.4435	$2.5335	3.68%		$2.5335
Retail Transmission Rate - Line and Transformation Connection Service Rate- Interval Metered	$/kW	$1.9938	$2.0359	2.11%		$2.0359
Large Use						
Retail Transmission Rate - Network Service Rate	$/kW	$2.9508	$3.0595	3.68%		$3.0595
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	$2.4076	$2.4584	2.11%		$2.4584
Unmetered Scattered Load						
Retail Transmission Rate - Network Service Rate	$/kWh	$0.0057	$0.0059	3.51%		$0.0059
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	$0.0046	$0.0047	2.17%		$0.0047
Sentinel Lighting						
Retail Transmission Rate - Network Service Rate	$/kW	$1.8036	$1.8700	3.68%		$1.8700
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	$1.4715	$1.5026	2.11%		$1.5026
Street Lighting						
Retail Transmission Rate - Network Service Rate	$/kW	$2.1701	$2.2500	3.68%		$2.2500
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	$1.7705	$1.8079	2.11%		$1.8079

8.3 Are the proposed LV rates appropriate?

Status: **Complete Settlement**

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence:

Interrogatory responses Energy Probe IRR # 45

Interrogatory responses VECC IRR # 35

For the purposes of settlement, the Parties accept the proposed LV rates for GS 50 to 999 kW, Sentinel Lighting and Street Lighting classes. The remaining amount of $20,241, shortfall revenue will be tracked in the account 1550 – Low Voltage variance.

Customer Class	Forecast 2012 kW	Low Voltage Rate Adders	2012 Low Voltage Revenue	Shortfall from $36,400 LV cots
	kW	kW	$	$36,400
GS 50 to 999 kW	1,041,992	0.0152	15,838	
Sentinel Lights	251	0.0112	3	
Street Lighting	27,447	0.0135	371	
TOTALS	1,069,689		$16,212	$20,188

8.4 Are the proposed loss factors appropriate?

Status: **Complete Settlement**

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence: Interrogatory responses VECC IRR # 36, 37

For the purposes of settlement, the Parties accept the Loss Factor of 1.0209 proposed by Guelph Hydro in its Application.

9. DEFERRAL AND VARIANCE ACCOUNTS

9.1 Are the account balances, cost allocation methodology and disposition period appropriate?

Status: **Complete Settlement**

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence:

Interrogatory responses Board Staff IRR # 62, 63, 64, 65, 66, 67, 68, 69, 70, JTC # 1.7

Interrogatory responses Energy Probe IRR # 46, 47, 48, TCQ # 22

For the purposes of settlement, the Parties accept the account balances, cost allocation methodology and disposition periods proposed by the Applicant.

For the purposes of settlement, the Parties have agreed to the disposal of the post retirement actuarial gain as outlined in Section 4.4.

For the purposes of settlement the Parties have agreed to the disposal of the PP&E deferral account as outlined in Section 11.1.

9.2 Are the proposed rate riders to dispose of the account balances appropriate?

Status: **Complete Settlement**

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence: Interrogatory responses Board Staff IRR # 71, 72, TCQ # 26

For the purposes of settlement, the Parties accept the proposed rate riders to dispose of the account balances .

~~Rate Class & Consumption per Month~~	Charge Unit	Proposed Rate Riders forDeferral and Variance		Proposed Rate Riders for Global Adjustment Sub-Account
Residential 800 kWh	kWh	-$0.0020		-$0.0001
General Service < 50 kW 2,000 kWh	kWh	-$0.0014		-$0.0001
General Service 50 to 999 kW 160 kW	kW	-$0.4521		-$0.3686
General Service >1000 kW 2,200 kW	kW	-$0.5195		-$0.4403
Large Use	kW	-$0.6221		-$0.5319
Unmetered Scattered Load 550 kWh	kWh	-$0.0027		-$0.0010
Street Lighting 2,100 kW	kW	-$2.7745		-$0.0013
Sentinel Lighting 0.3 kW	kW	-$0.9850		-$0.0013

9.3 Are the proposed balances for Other Regulatory Assets – Sub-account Deferred IFRS Transition Costs appropriate?

Status: Complete Settlement

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence:

Interrogatory responses Board Staff IRR # 73 (filed 2011/10/11)

Interrogatory responses Energy Probe IRR # 49

Interrogatory responses SEC IRR # 49, 50

For the purposes of settlement, the Parties accept the proposed balance $455,814 for Other Regulatory Assets – Sub-account Deferred IFRS Transition Costs.

10. LOST REVENUE ADJUSTMENT MECHANISM

10.1 Is the proposal related to LRAM/SSM appropriate?

Status: Complete Settlement

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence:

Interrogatory responses Board Staff IRR # 74, 75

Interrogatory responses VEC IRR # 38, 39, 40, 41

For the purposes of settlement, the Parties accept the Applicant's proposal related to LRAM/SSM .

2012 Test Year - LRAM and SSM Rate Rider

	Amounts (2007 to 2009)		Billing Units (2012)		Rate Riders			Three Year Rate Rider	Four Year Rate Rider	Number of Years to Use	Rate Rider to Use
	LRAM	SSM			LRAM	SSM	Total	Total	Total	(3 or 4)	Total
Rate Class	$	$		Metrics	$/unit (kWh or kW)	$/unit (kWh or kW)	$/unit (kWh or kW)	$/unit (kWh or kW)	$/unit (kWh or kW)	4	$/unit (kWh or kW)
Residential	$444,361	$23,362	378,871,008	kWh	0.0012	0.0001	0.0012	0.0004	0.0003		0.0003
GS < 50 kW	$39,918		148,787,703	kWh	0.0003	0.0000	0.0003	0.00009	0.0001		0.0001
GS 50 to 999 kW	$14,934	$12,119	1,041,992	kW	0.0143	0.0116	0.0260	0.0087	0.0065		0.0065
GS 1000 to 4999 kW	$17,164	$7,639	1,015,196	kW	0.0169	0.0075	0.0244	0.0081	0.0061		0.0061
Large Use	$16,624	$2,864	490,512	kW	0.0339	0.0058	0.0397	0.0132	0.0099		0.0099
USL	$42,512		2,229,301	kWh	0.0191	0.0000	0.0191	0.0064	0.0048		0.0048
Total	$575,514	$45,984									

11. MODIFIED INTERNATIONAL FINANCIAL REPORTING STANDARDS

11.1 Is the proposed revenue requirement determined using modified IFRS appropriate?

Status: **Complete Settlement**

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence:

Interrogatory responses Board Staff IRR # 76, 78, 79, 80, 82, 83, TCQ # 23, 24, 25, 27, 28, 29, 30, 31, 32, JTC # 1.8, 1.9, 1.11, IRR # 77, 81

Interrogatory responses Energy Probe IRR # 50

Interrogatory responses VECC IRR # 42, 43, 44, 45

Interrogatory responses SEC IRR # 52, 53, 54, 55, TCQ # 17, 18, 19, 20, 21, 22, 23, 24, JTC # 1.29, 1.30, 1.31, IRR # 51

The Parties agree to a Service Revenue Requirement, based on IFRS, of $28,590,938.

Service Revenue Requirement	$28,590,938
Less: Revenue Offsets	$2,207,000
Total Base Revenue Requirement	$26,383,938

For the purposes of settlement, the Parties have agreed to the disposal of the post retirement actuarial gain as outlined in Section 4.4.

For the purposes of settlement, the Parties have agreed to the calculation and treatment of the PP&E deferral account amounting to $1,940,000 ($1,526,000 Deferral account + $414,000 Return on rate base associated with deferred balance) in accordance with Board policy as presented in Appendix 1. The Applicant is proposing a four year amortization period of the Deferral account amounting to $485,000 per year. The Applicant's revenue requirement will be offset by the amortization of the Deferral account in 2012 and in the three subsequent years (2013-2015) for which the Applicant is under an Incentive Rate Mechanism Environment.

12. GREEN ENERGY ACT PLAN

12.1 Is Guelph Hydro's Green Energy Act Plan, including the Smart Grid component of the plan appropriate?

Status: No Settlement (left for Oral Hearing according OEB PO NO. 2)

Supporting Parties: Guelph Hydro, Energy Probe, SEC, VECC

Evidence: Interrogatory responses Board Staff IRR # 84, 85, 88, 90, 91, 92, 93, 94, TCQ # 33, 34, 35, 36, 37, 38, 39, 40, 41, 42, 43, 44, 45, 46, JTC # 1.12, 1.14, 1.16, IRR # 86,87,89 (filed 2011/10/11)

Interrogatory responses Energy Probe IRR # 51

The GEA Plan issue no. 12.1 is not eligible for settlement.

APPENDIX A

Appendix A

Summary of the Significant Iems Adjusted as a Result of this Settlement Agreement

Summary Of Significant Items Adjusted			
	Original As per Application (A)	Settlement Submission (B)	Difference (C= B-A)
Rate Base			
Gross Fixed Assets (average)	$178,018,480	$177,644,810	($373,670)
Accumulated Depreciation (average)	($63,313,009)	($62,623,827)	$689,182
Allowance for Working Capital:			
Controllable Expenses	$15,611,241	$14,326,000	($1,285,241)
Cost of Power	$143,312,358	$153,524,605	$10,212,247
Utility Income			
Operating Revenues:			
Distribution Revenue at Current Rates	$24,708,000	$24,763,956	$55,956
Distribution Revenue at Proposed Rates	$30,652,117	$26,383,971	($4,268,146)
Other Revenue:			
Specific Service Charges	$416,655	$572,666	$156,011
Operating Expenses:			
OM+A Expenses	$15,611,241	$14,326,000	($1,285,241)
Depreciation/Amortization	$6,831,714	$4,659,567	($2,172,147)
Property taxes			
Other expenses			
Taxes/PILs			
Taxable Income:			
Adjustments required to arrive at taxable income	($3,255,915)	($4,586,542)	($1,330,627)
Utility Income Taxes and Rates:			
Income taxes (not grossed up)	$538,936	$66,273	($472,664)
Income taxes (grossed up)	$730,761	$73,246	($657,516)
Federal tax (%)	15.00%	5.44%	
Provincial tax (%)	11.25%	4.08%	
Cost of Capital			
Long-term debt Cost Rate (%)	5.26%	5.26%	
Short-term debt Cost Rate (%)	2.46%	2.08%	
Common Equity Cost Rate (%)	9.58%	9.42%	

APPENDIX B

Table 8 Appendix 2-B
Fixed Asset Continuity Schedule
As of December 31, 2011

Fixed Asset Continuity Schedule (Distribution & Operations)
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
N/A	1805	Land	2,641,987			2,641,987	0			0	2,641,987
CEC	1806	Land Rights	0			0	0			0	0
1	1808	Buildings and Fixtures	18,260,502	1,735,000		19,995,502	2,705,497	426,613		3,132,110	16,863,391
N/A	1810	Leasehold Improvements	0			0	0			0	0
	1815	Transformer Station Equipment - Normally Primary a	758,177	9,225,000		9,983,177	25,273	332,773		358,045	9,625,132
47	1820	Distribution Station Equipment - Normally Primary be	1,708,887			1,708,887	129,970	73,394		203,364	1,505,523
	1825	Storage Battery Equipment	0			0	0			0	0
47	1830	Poles, Towers and Fixtures	22,276,501	1,322,234		23,598,735	8,001,755	512,411		8,514,166	15,084,569
47	1835	Overhead Conductors and Devices	17,880,210	1,224,591		19,104,801	6,709,061	411,330		7,120,391	11,984,409
47	1840	Underground Conduit	37,660,552	2,625,270		40,285,822	13,309,293	901,036		14,210,329	26,075,494
47	1845	Underground Conductors and Devices	35,823,198	2,595,379		38,418,577	12,199,463	861,506		13,060,969	25,357,609
47	1850	Line Transformers	18,187,753	1,033,848		19,221,601	7,194,113	402,358		7,596,471	11,625,130
47	1855	Services	7,183,493	269,265		7,452,758	2,593,145	171,443		2,764,588	4,688,170
47	1860	Meters	6,634,663	609,000		14,725,108	1,537,947	474,125		3,123,682	11,601,427
	1865	Other Installations on Customer's Premises	0			0	0			0	0
N/A	1905	Land	0			0	0			0	0
CEC	1906	Land Rights	0			0	0			0	0
1	1908	Buildings and Fixtures	0			0	0			0	0
	1910	Leasehold Improvements	0			0	0			0	0
	1915	Office Furniture and Equipment	1,221,843			1,221,843	750,797	45,425		796,222	425,621
45	1920	Computer Equipment - Hardware	2,502,577	420,000		3,549,349	1,737,566	362,335		2,099,901	1,449,448
	1925	Computer Software	0			1,114,457	0			0	1,114,457
10	1930	Transportation Equipment	2,881,072	450,000		3,331,072	1,349,158	338,917		1,688,075	1,642,996
	1935	Stores Equipment	96,338			96,338	96,338			96,338	0
8	1940	Tools, Shop and Garage Equipment	992,103	60,000		1,103,006	608,968	72,980		681,948	421,058
	1945	Measurement and Testing Equipment	14,872			14,872	14,872			14,872	0
	1950	Power Operated Equipment	0			0	0			0	0
	1955	Communication Equipment	0			0	0			0	0
50	1960	Miscellaneous Equipment	2,332,949	50,000		2,439,448	2,249,423	79,094		2,328,517	110,931
	1970	Load Management Controls - Customer Premises	314,982			314,982	314,982			314,982	(0)
	1975	Load Management Controls - Utility Premises	0			0	0			0	0
50	1980	System Supervisory Equipment	526,929	361,093		888,022	175,777	177,604		353,381	534,641
	1985	Sentinel Lighting Rentals	6,158			6,158	0			0	6,158
	1990	Other Tangible Property	0			0	0			0	0
47	1995	Contributions and Grants	(35,235,111)	(2,679,000)		(37,914,111)	(7,444,651)	(914,706)		(8,359,357)	(29,554,754)
	2005	Property Under Capital Leases	0			0	0			0	0
	2070	Other Utility Plant	771			771	424	51		476	295
Total before Work in Process / Re-allocation of amortization			**144,671,404**	**19,301,680**	**0**	**173,303,160**	**54,259,170**	**4,728,689**	**0**	**60,099,469**	**113,203,690**
95	2055	Work in Process	40,117			40,117	0				40,117
		Re-allocation of amortization						(332,817)			
		Total after Work in Process	**144,711,521**	**19,301,680**	**0**	**173,343,277**	**54,259,170**	**4,395,872**	**0**	**60,099,469**	**113,243,807**

Table 9 Appendix 2-B
Fixed Asset Continuity Schedule
As of December 31, 2012

Fixed Asset Continuity Schedule (Distribution & Operations)
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
N/A	1805	Land	2,641,987			2,641,987	0			0	2,641,987
CEC	1806	Land Rights	0			0	0			0	0
1	1808	Buildings and Fixtures	19,995,502	83,000		20,078,502	3,132,110	427,443		3,559,553	16,518,948
N/A	1810	Leasehold Improvements	0			0	0			0	0
	1815	Transformer Station Equipment - Normally Primary above 50 kV	9,983,177			9,983,177	358,045	249,579		607,624	9,375,553
47	1820	Distribution Station Equipment - Normally Primary below 50 kV	1,708,887			1,708,887	203,364	59,153		262,517	1,446,370
	1825	Storage Battery Equipment	0			0	0			0	0
47	1830	Poles, Towers and Fixtures	23,598,735	1,458,598		25,057,333	8,514,166	410,914		8,925,080	16,132,253
47	1835	Overhead Conductors and Devices	19,104,801	1,364,027		20,468,828	7,120,391	262,609		7,383,000	13,085,827
47	1840	Underground Conduit	40,285,822	2,439,416		42,725,238	14,210,329	935,306		15,145,635	27,579,604
47	1845	Underground Conductors and Devices	38,418,577	2,373,457		40,792,034	13,060,969	890,549		13,951,518	26,840,517
47	1850	Line Transformers	19,221,601	1,076,643		20,298,244	7,596,471	415,816		8,012,287	12,285,957
47	1855	Services	7,452,758	278,723		7,731,481	2,764,588	177,255		2,941,843	4,789,638
47	1860	Meters	14,725,108	625,000		15,350,108	3,123,682	750,635		3,874,317	11,475,792
	1865	Other Installations on Customer's Premises	0			0	0			0	0
CEC	1906	Land Rights	0			0	0			0	0
1	1908	Buildings and Fixtures	0			0	0			0	0
	1910	Leasehold Improvements	0			0	0			0	0
	1915	Office Furniture and Equipment	1,221,843			1,221,843	796,222	45,425		841,647	380,196
45	1920	Computer Equipment - Hardware	3,549,349	500,000		4,049,349	2,099,901	615,049		2,714,950	1,334,399
	1925	Computer Software	1,114,457	0		1,114,457	0	99,154		99,154	1,015,303
10	1930	Transportation Equipment	3,331,072	485,000		3,816,072	1,688,075	346,433		2,034,508	1,781,563
	1935	Stores Equipment	96,338			96,338	96,338			96,338	0
8	1940	Tools, Shop and Garage Equipment	1,103,006	65,000		1,168,006	681,948	76,799		758,747	409,259
	1945	Measurement and Testing Equipment	14,872			14,872	14,872			14,872	0
	1950	Power Operated Equipment	0			0	0			0	0
	1955	Communication Equipment	0	0		0	0	0		0	0
50	1960	Miscellaneous Equipment	2,439,448	159,436		2,598,884	2,328,517	23,216		2,351,733	247,151
	1970	Load Management Controls - Customer Premises	314,982			314,982	314,982			314,982	(0)
	1975	Load Management Controls - Utility Premises	0			0	0			0	0
50	1980	System Supervisory Equipment	888,022	200,000		1,088,022	353,381	208,348		561,729	526,293
	1985	Sentinel Lighting Rentals	6,158			6,158	0			0	6,158
	1990	Other Tangible Property	0			0	0			0	0
47	1995	Contributions and Grants	(37,914,111)	(2,425,000)		(40,339,111)	(8,359,357)	(945,019)		(9,304,376)	(31,034,735)
	2005	Property Under Capital Leases	0			0	0			0	0
	2070	Other Utility Plant	771			771	476	51		527	244
		Total before Work in Process	**173,303,160**	**8,683,300**	**0**	**181,986,460**	**60,099,469**	**5,048,715**	**0**	**65,148,184**	**116,838,275**
95	2055	Work in Process	40,117			40,117					40,117
		Re-allocation of amortization					0	(423,232)			
		Total after Work in Process	**173,343,277**	**8,683,300**	**0**	**182,026,577**	**60,099,469**	**4,625,483**	**0**	**65,148,184**	**116,878,392**

APPENDIX C

Electricity - Commodity		2012	Test year				%		RPP and Non-RPP Cost of Power		
Class per Load Forecast	**2012 Forecasted Metered kWhs**	**Proposed Loss Factor**	**Kwhs adjusted by DLF**	**RPP Prices**	**HOEP**	**Global Adjustment**	**RPP**	**Non-RPP**	**RPP $**	**Non-RPP $**	**Total Cost Of Power**
Residential	378,871,008	1.0209	386,781,856	0.07515	0.03138	$0.04008	86.96%	13.04%	$25,276,706	$3,603,858	$28,880,563
GS<50kW	148,787,703	1.0209	151,894,399	0.07515	0.03138	$0.04008	85.03%	14.97%	$9,706,179	$1,624,785	$11,330,965
GS 50kW to 999kW	399,661,950	1.0209	408,006,914	0.07515	0.03138	$0.04008	0.00%	100.00%	$0	$29,156,174	$29,156,174
GS 1000kW to 4999kW	465,120,498	1.0209	474,832,240	0.07515	0.03138	$0.04008	0.00%	100.00%	$0	$33,931,512	$33,931,512
Large Use	271,481,475	1.0209	277,150,023	0.07515	0.03138	$0.04008	0.00%	100.00%	$0	$19,805,141	$19,805,141
Unmetered Scattered Load	2,229,301	1.0209	2,275,849	0.07515	0.03138	$0.04008	0.00%	100.00%	$0	$162,632	$162,632
Sentinel Lighting	88,740	1.0209	90,593	0.07515	0.03138	$0.04008	99.62%	0.38%	$6,782	$24	$6,807
Street Lighting	9,777,748	1.0209	9,981,908	0.07515	0.03138	$0.04008	2.80%	97.20%	$21,004	$693,334	$714,339
TOTAL	**1,676,018,424**		**1,711,013,782**						$35,010,671	$88,977,460	**$123,988,132**

Transmission - Network		**Volume**			
Class per Load Forecast		**Metric**	**Test Year**		
Residential		kWh	386,781,856	$0.0064	$2,475,404
GS<50kW		kWh	151,894,399	$0.0059	$896,177
GS 50kW to 999kW		kW	1,041,992	$2.5335	$2,639,886
GS 1000kW to 4999kW		kW	1,015,196	$2.5335	$2,571,999
Large Use		kW	490,512	$3.0595	$1,500,721
Unmetered Scattered Load		kWh	2,275,849	$0.0059	$13,428
Sentinel Lighting		kW	251	$1.8700	$469
Street Lighting		kW	27,447	$2.2500	$61,755
TOTAL					**$10,159,839**

Transmission - Connection		**Volume**			
Class per Load Forecast		**Metric**	**Test Year**		
Residential		kWh	386,781,856	$0.0053	$2,049,944
GS<50kW		kWh	151,894,399	$0.0047	$713,904
GS 50kW to 999kW		kW	1,041,992	$2.0359	$2,121,391
GS 1000kW to 4999kW		kW	1,015,196	$2.0359	$2,066,837
Large Use		kW	490,512	$2.4584	$1,205,875
Unmetered Scattered Load		kWh	2,275,849	$0.0047	$10,696
Sentinel Lighting		kW	251	$1.5026	$377
Street Lighting		kW	27,447	$1.8079	$49,621
TOTAL					**$8,218,645**

Wholesale Market Service					
Class per Load Forecast			**Test Year**		
Residential		kWh	386,781,856	$0.0052	$2,011,266
GS<50kW		kWh	151,894,399	$0.0052	$789,851
GS 50kW to 999kW		kWh	408,006,914	$0.0052	$2,121,636
GS 1000kW to 4999kW		kWh	474,832,240	$0.0052	$2,469,128
Large Use		kWh	277,150,023	$0.0052	$1,441,180
Unmetered Scattered Load		kWh	2,275,849	$0.0052	$11,834
Sentinel Lighting		kWh	90,593	$0.0052	$471
Street Lighting		kWh	9,981,908	$0.0052	$51,906
TOTAL			**1,711,013,782**		**$8,897,272**

Rural Rate Assistance					
Class per Load Forecast			**Test Year**		
Residential		kWh	386,781,856	$0.0013	$502,816
GS<50kW		kWh	151,894,399	$0.0013	$197,463
GS 50kW to 999kW		kWh	408,006,914	$0.0013	$530,409
GS 1000kW to 4999kW		kWh	474,832,240	$0.0013	$617,282
Large Use		kWh	277,150,023	$0.0013	$360,295
Unmetered Scattered Load		kWh	2,275,849	$0.0013	$2,959
Sentinel Lighting		kWh	90,593	$0.0013	$118
Street Lighting		kWh	9,981,908	$0.0013	$12,976
TOTAL			**1,711,013,782**		**$2,224,318**

	Test Year	
4705-Power Purchased	$123,988,132	
4708-Charges-WMS	$8,897,272	
4714-Charges-NW	$10,159,839	
4716-Charges-CN	$8,218,645	
4730-Rural Rate Assistance	$2,224,318	
4750-Low Voltage	$36,400	monthly average
TOTAL	**153,524,605**	12,793,717

APPENDIX D

Appendix - D

2012 updated Customer Class Load Forecast

Description	Original as Per Application	As Per Settlement	Change
	A	B	B-A
2012 Billed kWh			
By Class			
Residential			
Customers	47,848	47,848	0
kWh	377,742,193	378,871,008	1,128,815
GS < 50 kW			
Customers	3,788	3,788	0
kWh	148,344,402	148,787,703	443,301
GS 50 to 999 kW			
Customers	569	569	0
kWh	398,859,229	399,661,950	802,721
kW	1,039,899	1,041,992	2,093
GS1000 to 4999 kW			
Customers	44	44	0
kWh	464,907,759	465,120,498	212,740
kW	1,014,732	1,015,196	464
Large User			
Customers	4	4	0
kWh	271,062,702	271,481,475	418,773
kW	489,755	490,512	757
Streetlights			
Customers	13,609	13,609	0
kWh	9,777,748	9,777,748	0
kW	27,447	27,447	0
Sentinel Lights			
Customers	26	26	0
kWh	88,740	88,740	0
kW	251	251	0
Unmetered Scattered Load			
Customers	583	583	0
kWh	2,229,301	2,229,301	0
Total of Above			
Customers	66,470	66,470	0
kWh	1,673,012,075	1,676,018,424	3,006,349
kW from applicable classes	2,572,083	2,575,397	3,314
2012 Revenues at Existing Rates			
Revenues at Existing Rates	$24,708,000	$24,763,956	55,956

APPENDIX E

Appendix E

2012 Test Year Updated Other Revenue

Change in Other Revenue

USoA	Description	2012 As Filed	2012 As Per Settlement Agreement	Change
4080	4080 - Distribution Services Revenue SSS Administration Charge			-
4082	4082 - RS Rev	8,250	8,250	-
4084	4084 - Serv Tx Requests	7,600	7,600	
4210	4210 - Rent from Electric Property	390,358	390,358	-
4220	4220 - Other Electric Revenues			-
4225	4225-Late Payment Charges	127,572	127,572	-
4235	4235 - Miscellaneous Service Revenues **(Note 1)**	264,893	420,903	156,010
4355	4355-Gain on Disposition of Utility and Other Property	79,811	79,811	-
4375	4375-Revenues from Non-Utility Operations	1,540,560	1,540,560	-
4380	4380-Expenses of Non-Utility Operations	(601,752)	(601,752)	-
4390	4390-Miscellaneous Non-Operating Income	135,912	135,912	-
4405	4405-Interest and Dividend Income	97,786	97,786	-
Other Distribution Revenue Before Adjustments		2,050,990	2,207,000	156,010
	Adjustments - Less:			
4355	4355-Gain on Disposition of Utility and Other Property			-
4375	OPA Programs Incentive Revenue			-
Other Revenue with Offsets		2,050,990	2,207,000	156,010

Other Distribution Revenue			
Late Payment Charges	127,572	127,572	-
Specific Service Charges	15,850	15,850	-
Interest Income	97,786	97,786	-
Other Revenue **(Note1)**	1,809,782	1,965,792	156,010
Total	2,050,990	2,207,000	156,010

Note 1 Adjustment made to bring total of Other Revenue to 2010 levels as per Settlement Conference agreement.

APPENDIX F

Appendix F

2012 Test Year Updated OM&A

Change in Operations, Maintenance & Administration

Description	As per Application	As per Settlement Agreement	Change	Notes
Operations	3,815,492	3,815,492	-	
Maintenance	1,850,075	1,850,075	-	
Billing & Collecting	2,684,296	2,574,296	(110,000)	2
Community Relations	458,735	458,735	-	
Administration & General Expense	5,913,766	5,627,402	(286,364)	1
OM&A Adjustment Difference		-	-	
Total OM&A	**14,722,364**	**14,326,000**	**(396,364)**	

Notes:

1. Decrease in Administration & General Expense due to:

Reduction in communications budget	$	(150,000)
Reduction in other outside contracted services and professional fees		(223,614)
Increase in OMERS expense due to contribution rate increases announced for 2012 and 2013.		87,250
	$	(286,364)

APPENDIX G

Appendix G

2012 Test Year Updated PILs

Schedule 8 CCA 2011 Bridge Year

Class	Class Description	UCC Bridge Year Opening Balance	Additions	Disposals	UCC Before 1/2 Yr Adjustment	1/2 Year Rule (1/2 Additions Less Disposals)	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - 1988 to feb 22/05	61,371,840	1,735,000		63,106,840	867,500	62,239,340	4%	2,489,573.60	60,617,266
2	Distribution System - pre 1988	10,186,614			10,186,614	-	10,186,614	6%	611,197	9,575,417
8	General Office/Stores Equipment	9,523,531	167,402		9,690,933	83,701	9,607,232	20%	1,921,446	7,769,487
10	Computer Hardware/Vehicles	1,268,412	450,000		1,718,412	225,000	1,493,412	30%	448,024	1,270,388
1b	Building - Non-Residential	176,464			176,464	-	176,464	6%	10,588	165,876
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	79,214			79,214		79,214	8%	6,337	72,877
42	Fibre Optic Cable	372			372		372	12%	45	327
45	Computer & Systems Hardware Acq'd Post	44,892			44,892	-	44,892	45%	20,201	24,691
50	Computer & Systems Hardware Acq'd Post	65,862	2,572,322		2,638,184	1,286,161	1,352,023	55%	743,613	1,894,571
47	Distribution System Post	26,286,685	16,267,104		42,553,789	8,133,552	34,420,237	8%	2,753,619	39,800,170
SUB-TOTAL-UCC		109,003,886	21,191,828	-	130,195,714	10,595,914	119,599,800		9,004,643	121,191,071

Schedule 8 CCA 2012 Test Year

Class	Class Description	UCC Test Year Opening Balance	Additions	Disposals	UCC Before 1/2 Yr Adjustment	1/2 Year Rule (1/2 Additions Less Disposals)	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - 1988 to feb 22/05	60,617,266	83,000		60,700,266	41,500	60,658,766	4%	2,426,351	58,273,916
2	Distribution System - pre 1988	9,575,417			9,575,417	-	9,575,417	6%	574,525	9,000,892
8	General Office/Stores Equipment	7,769,487	65,000		7,834,487	32,500	7,801,987	20%	1,560,397	6,274,089
10	Computer Hardware/Vehicles	1,270,388	485,000		1,755,388	242,500	1,512,888	30%	453,867	1,301,522
1b	Building - Non-Residential	165,876			165,876	-	165,876	6%	9,953	155,924
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	72,877			72,877	-	72,877	8%	5,830	67,047
42	Fibre Optic Cable	327			327		327	12%	39	288
45	Computer & Systems Hardware Acq'd Post	24,691			24,691		24,691	45%	11,111	13,580
50	Computer & Systems Hardware Acq'd Post	1,894,571	859,436		2,754,007	429,718	2,324,289	55%	1,278,359	1,475,648
47	Distribution System Post	39,800,170	7,417,564		47,217,734	3,708,782	43,508,952	8%	3,451,656.16	43,766,078
SUB-TOTAL-UCC		121,191,071	8,910,000	-	130,101,071	4,455,000	125,646,071		9,772,088	120,328,983

Taxable Income Test Year

Determination of Tax Adjustments to Accounting Income for 2012

Line Item	T2S1 Line #	Total for Legal Entity	No-distribution Eliminations	Utility Amount
Additions:				
Interest and penalties	103			
Amortization of tangible assets	104	5,048,715		5,048,715
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			
Scienific research expenditures deducted on financial statements	118			
Capitalized Interest	119			
Non-deductible club dues and fees	120			
Non-deductible meals and entertainment expense	121			
Non-deductible automobile expenses	122			
Non-deductible life insurance premiums	123			
Non-deductible company pensioon plans	124			
Tax reserves end of year	125			
Reserves from financial statements- balance at end of year	126	7,472,938		7,472,938
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			
Interest Expense on Capital Leases	290			
realized Income from Deferred Credit Accounts	291			
Pensions	292			
Non-deductible penalties	293			
Debt Financing Expenses for Book Purposes	294			
Other Additions (Apprenticeship Tax Credits)	295			
Total Additions:		12,521,653	0	12,521,653
Deductions:				
Gain on disposal of assets per financial statements	401			
Dividends not taxable under section 83	402			
Capital cost allowance from Schedule 8	403	9,772,088		9,772,088
Terminal loss from Schedule 8	404			
Cumulative eligible deduction from Schedule 10	405	212,654		212,654
Allowable business investment loss	406			
Deferred and prepaid expenses	409			
Scientific research expenses claimed in year	411			
Tax reserves begining of year	413			
Reserves from financial statements - balance at beginning of year	414	7,123,453		7,123,453
Contributions to deferred plans	416			
Book Income of joint venture or partnership	305			
Equity in income from subsidiary or affiliates	306			
Interest capitalized for accounting deducted for tax	390			
Capital Lease Payments	391			
Non-taxable impted income on deferral and variance accounts	392			
Financing Fees for Tax Under S.20(1)€	393			
Other Deductions	394			
Total Deductions:		17,108,195		17,108,195
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 7-1	331			
Net-capital losses of preceding taxation years from Schedule 7-1	332			
Limited partnership losses of preceding taxations years from Schdule 4	335			
Total Adjustments:		0	0	0
Tax Adjustments to Accounting Income		(4,586,542)	0	(4,586,542)

PILs, Tax Provision

					Wires Only	
Regulatory Taxable Income					696,140	A
Ontario Income Taxes						
Income Tax Payable	Ontario Income Tax					
Combined Tax Rate and PILs	Effective Ontario Tax Rate					
	Federal Tax Rate					
	Combined Tax Rate			Effective Tax Rate	28.0149%	B
Total Income Taxes				A x B	195,023	C
Reduction due to Fed/Ontario Small Business Threshold					53,750	
Miscellaneous Tax Credits(Apprentice, Co-op)					75,000	
Total Reductions					128,750	D
Corporate PILs/ Income Tax Provision for Test Year					66,273	C-D
Corporate PILs/ Income Tax Provision Gross Up					73,246	

APPENDIX H

Appendix H

2012 Test Year Updated Cost of Capital

Debt & Capital Cost Structure

Weighted Debt Cost

Description	Debt Holder	Affliated with LDC?	Date of Issuance		Principal	Term (Years)	Rate%		Year Applied to	Interest Cost
Promissory note	City of Guelph	Y	June 4, 2008		$30,000,000	0	6.10%	0.00%	2008	$1,830,000
Promissory note	Guelph Hydro Inc.(GHI)	Y	April 30, 2002		$12,558,000	0	6.10%	0.00%	2008	$766,038
Promissory note	City of Guelph	Y	June 4, 2008		$30,000,000	0	6.10%	0.00%	2009	$1,830,000
Promissory note	Guelph Hydro Inc.(GHI)	Y	April 30, 2002		$12,558,000	0	6.10%	0.00%	2009	$766,038
Promissory note	City of Guelph	Y	June 4, 2008		$30,000,000	0	6.10%	0.00%	2010	$1,830,000
Promissory note	Guelph Hydro Inc.(GHI)	Y	April 30, 2002		$12,558,000	0	6.10%	0.00%	2010	$766,038
Senior Unsecured Debentures, Series A		N	December 6, 2010		$65,000,000	0	5.264%	0.00%	2011	$3,421,600
Senior Unsecured Debentures, Series A		N	December 6, 2010		$65,000,000	0	5.264%	0.00%	2012	$3,421,600

2008 Total Long Term Debt	42,558,000	Total Interest Cost for 2008	2,596,038
		Weighted Debt Cost Rate for 2008	6.10%
2009 Total Long Term Debt	42,558,000	Total Interest Cost for 2009	2,596,038
		Weighted Debt Cost Rate for 2009	6.10%
2010 Total Long Term Debt	42,558,000	Total Interest Cost for 2010	2,596,038
		Weighted Debt Cost Rate for 2010	6.10%
2011 Total Long Term Debt	65,000,000	Total Interest Cost for 2011	3,421,600
		Weighted Debt Cost Rate for 2011	5.26%
2012 Total Long Term Debt	65,000,000	Total Interest Cost for 2012	3,421,600
		Weighted Debt Cost Rate for 2011	5.264%

APPENDIX H- 2012 Test Year Updated Cost of Capital – cont.

Initial Application

Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
Debt				
Long-term Debt	56.00%	$77,584,646	5.26%	$4,084,056
Short-term Debt	4.00%	$5,541,760	2.46%	$136,327
Total Debt	60.00%	$83,126,407	5.08%	$4,220,383
Equity				
Common Equity	40.00%	$55,417,604	9.58%	$5,309,007
Preferred Shares	0.00%	$ -	0.00%	$ -
Total Equity	40.00%	$55,417,604	9.58%	$5,309,007
Total	100.00%	$138,544,011	6.88%	$9,529,390

Updated Cost of Capital

Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
Debt				
Long-term Debt	56.00%	$78,511,201	5.26%	$4,132,830
Short-term Debt	4.00%	$5,607,943	2.08%	$116,645
Total Debt	60.00%	$84,119,144	5.05%	$4,249,475
Equity				
Common Equity	40.00%	$56,079,429	9.42%	$5,282,682
Preferred Shares	0.00%	$ -	0.00%	$ -
Total Equity	40.00%	$56,079,429	9.42%	$5,282,682
Total	100.00%	$140,198,573	6.80%	$9,532,157

APPENDIX I

2012 TEST YEAR UPDATED REVENUE DEFICIENCY

Particulars	Initial Application		Settlement Agreement	
	At Current Approved Rates	**At Proposed Rates**	**At Current Approved Rates**	**At Proposed Rates**
Revenue Deficiency from Below		$5,944,117		$1,620,014
Distribution Revenue	$24,708,000	$24,708,000	$24,763,956	$24,763,957
Other Operating Revenue Offsets - net	$2,050,989	$2,050,989	$2,207,000	$2,207,000
Total Revenue	$26,758,989	$32,703,106	$26,970,956	$28,590,971
Operating Expenses	$22,442,955	$22,442,955	$18,985,567	$18,985,567
Deemed Interest Expense	$4,220,383	$4,220,383	$4,249,475	$4,249,475
Total Cost and Expenses	$26,663,338	$26,663,338	$23,235,042	$23,235,042
Utility Income Before Income Taxes	$95,651	$6,039,768	$3,735,914	$5,355,929
Tax Adjustments to Accounting Income per 2009 PILs	($3,255,915)	($3,255,915)	($4,586,542)	($4,586,542)
Taxable Income	($3,160,265)	$2,783,852	($850,628)	$769,387
Income Tax Rate	26.25%	26.25%	9.52%	9.52%
Income Tax on Taxable Income	($829,569)	$730,761	($80,980)	$73,246
Income Tax Credits	$ -	$ -	$ -	$ -
Utility Net Income	$925,220	$5,309,007	$3,816,894	$5,282,683
Utility Rate Base	$138,544,011	$138,544,011	$140,198,573	$140,198,573
Deemed Equity Portion of Rate Base	$55,417,604	$55,417,604	$56,079,429	$56,079,429
Income/(Equity Portion of Rate Base)	1.67%	9.58%	6.81%	9.42%
Target Return - Equity on Rate Base	9.58%	9.58%	9.42%	9.42%
Deficiency/Sufficiency in Return on Equity	-7.91%	0.00%	-2.61%	0.00%
Indicated Rate of Return	3.71%	6.88%	5.75%	6.80%
Requested Rate of Return on Rate Base	6.88%	6.88%	6.80%	6.80%
Deficiency/Sufficiency in Rate of Return	-3.16%	0.00%	-1.05%	0.00%
Target Return on Equity	$5,309,007	$5,309,007	$5,282,682	$5,282,682
Revenue Deficiency/(Sufficiency)	$4,383,786	$ -	$1,465,789	$1
Gross Revenue Deficiency/(Sufficiency)	$5,944,117 **(1)**		$1,620,014 **(1)**	

APPENDIX J

2012 TEST YEAR UPDATED REVENUE TO COST RATIOS

Appendix J

2012 Test Year Updated Revenue to Cost Ratios

Rate Classification	Distribution Revenue @ Existing Rate % (per Application)	Distribution Revenue @ Existing Rate % (per Settlement)	Fixed Distribution Revenue (per Application)	Fixed Distribution Revenue (per Settlement)	Variable Distribution Revenue (per Application)	Variable Distribution Revenue (per Settlement)	Transformer Allowance (per Application)	Transformer Allowance (per Settlement)	GrossServ Rev Requirement Excl Transformer Allowance (per Application)	Gross Serv Rev Requirement Excl Transformer Allowance (per Settlement)	LV Wheeling Charges (per Application)	LV Wheeling Charges (per Settlement)	Total (per Application)	Total (per settlement)	Revenue to Cost Ratios Per C.A. Study (per Application)	Revenue to Cost Ratios Per C.A. Study (per New updated CA and Settlement)	Revenue to Cost Ratios (per Application)	Revenue to C Ratios (pe settlement
Customer Class	56.19%	56.18%	$9,489,547	$8,203,411	$7,620,043	$6,619,952			$17,109,590	$14,823,363	$14,957	$14,950	$17,124,547	$14,838,312	100.62%	97.86%	100.00%	97
Residential	11.60%	11.62%	$500,241	$681,806	$2,073,299	$1,987,680			$2,573,539	$3,066,644	$5,209	$5,206	$2,578,748	$3,071,851	135.54%	136.62%	100.00%	120
GS < 50 kW	17.11%	17.11%	$1,119,595	$1,328,554	$2,041,332	$2,244,090	$220,988	$220,998	$3,160,927	$4,514,662	$15,782	$15,794	$3,397,697	$4,751,454	161.36%	150.08%	100.00%	120
GS 50 to 999 kW	9.45%	9.43%	$680,128	$324,459	$4,213,106	$3,389,428			$4,893,234	$2,488,671	$0	$0	$4,893,234	$2,488,671	61.66%	57.57%	100.00%	83
GS > 1000 kW	4.49%	4.49%	$99,972	$43,566	$2,443,491	$1,140,236			$2,543,464	$1,183,802	$0	$0	$2,543,464	$1,183,802	56.92%	111.58%	100.00%	111
Large Use	0.015%	0.015%	$2,182	$2,151	$1,957	$1,928			$4,139	$4,079	$3	$3	$4,142	$4,082	118.72%	104.04%	100.00%	104
Sentinel Lights	0.77%	0.77%	$53,354	$62,538	$216,635	$253,925			$269,989	$202,502	$370	$369	$270,359	$202,871	113.94%	56.32%	100.00%	83
Street Lighting	0.38%	0.38%	$39,622	$40,836	$57,613	$59,378			$97,235	$100,215	$78	$78	$97,313	$100,293	88.02%	111.18%	100.00%	111
TOTAL	**100.00%**	**100.00%**	**$11,984,641**	**$10,687,321**	**$18,667,476**	**$15,696,617**	**$220,988**	**$220,998**	**$30,652,117**	**$26,383,938**	**$36,400**	**$36,400**	**$30,909,505**	**$26,641,336**				

APPENDIX K

2012 TARIFF OF RATES AND CHARGES

Schedule of Proposed Rates & Charges (2012) - Settlement

Monthly Rates and Charges

Residential	**Metrics**	**Rate**
Service Charge	$/month	14.29
Smart Meter Disposition Rate Rider - effective until December 31, 2012	$/month	(0.12)
Stranded Meter Cost Recovery Rate Rider - effective until December 31, 2015	$/month	0.73
Post Retairement actuarial Gain Disposition Rate Rider - effective until December 31, 2024	$/month	(0.18)
PILs Recovery Rate Rider - effective until December 31, 2015	$/month	0.45
GEA Plan - Renewable Connection- Funding Rate Adder - effective until December 31, 2012	$/month	0.10
GEA Plan - Smart Grid - Funding Rate Adder - effective until December 31, 2012	$/month	0.83
Rate Rider for Recovery of Late Payment Litigation Costs - effective until April 30, 2012	$/month	0.22
Distribution Volumetric Rate	$/kWh	0.0174
Rate Rider for Global Adjustment Sub-Account Disposition- effective until December 31, 2012	$/kWh	(0.0001)
Rate Rider for Deferral/Variance Account- effective until December 31, 2012	$/kWh	(0.0020)
LRAM/SSM Recovery- effective until December 31, 2015	$/kWh	0.0003
Retail Transmission Rate – Network Service Rate	$/kWh	0.0064
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0053
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$/month	0.2500

	Metrics	**Rate**
General Service less than 50 kW		
Service Charge	$/month	15.00
Smart Meter Disposition Rate Rider - effective until December 31, 2012	$/month	(0.25)
Stranded Meter Cost Recovery Rate Rider - effective until December 31, 2015	$/month	0.73
Post Retairement actuarial Gain Disposition Rate Rider - effective until December 31, 2024	$/month	(0.50)
PILs Recovery Rate Rider - effective until December 31, 2015	$/month	1.26
GEA Plan - Renewable Connection- Funding Rate Adder - effective until December 31, 2012	$/month	0.10
GEA Plan - Smart Grid - Funding Rate Adder - effective until December 31, 2012	$/month	0.83
Rate Rider for Recovery of Late Payment Litigation Costs - effective until April 30, 2012	$/month	0.57
Distribution Volumetric Rate	$/kWh	0.0134
Rate Rider for Global Adjustment Sub-Account Disposition- effective until December 31, 2012	$/kWh	(0.0001)
Rate Rider for Deferral/Variance Account- effective until December 31, 2012	$/kWh	(0.0014)
LRAM/SSM Recovery- effective until December 31, 2015	$/kWh	0.0001
Retail Transmission Rate – Network Service Rate	$/kWh	0.0059
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0047
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$/month	0.25

General Service 50 to 999 kW	**Metrics**	**Rate**
Service Charge	$/month	167.22
Smart Meter Disposition Rate Rider - effective until December 31, 2012	$/month	(0.90)
Stranded Meter Cost Recovery Rate Rider - effective until December 31, 2015	$/month	0.73
Post Retairement actuarial Gain Disposition Rate Rider - effective until December 31, 2024	$/month	(3.80)
PILs Recovery Rate Rider - effective until December 31, 2015	$/month	9.58
GEA Plan - Renewable Connection- Funding Rate Adder - effective until December 31, 2012	$/month	0.10
GEA Plan - Smart Grid - Funding Rate Adder - effective until December 31, 2012	$/month	0.83
Rate Rider for Recovery of Late Payment Litigation Costs - effective until April 30, 2012	$/month	4.21
Distribution Volumetric Rate	$/kW	2.5446
Low Voltage Rate Adder - effective until December 31, 2015	$/kW	0.0152
Rate Rider for Global Adjustment Sub-Account Disposition- effective until December 31, 2012	$/kW	(0.3686)
Rate Rider for Deferral/Variance Account- effective until December 31, 2012	$/kW	(0.4521)
LRAM/SSM Recovery- effective until December 31, 2015	$/kW	0.0065
Retail Transmission Rate – Network Service Rate	$/kW	2.4425
Retail Transmission Rate – Network Service Rate - Interval Metered	$/kW	2.5335
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.9624
Retail Transmission Rate – Line and Transformation Connection Service Rate - Interval Metered	$/kW	2.0359
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 1000 to 4999 kW	**Metrics**	**Rate**
Service Charge	$/month	620.07
Smart Meter Disposition Rate Rider - effective until December 31, 2012	$/month	(1.07)
Stranded Meter Cost Recovery Rate Rider - effective until December 31, 2015	$/month	0.73
Post Retairement actuarial Gain Disposition Rate Rider - effective until December 31, 2024	$/month	(46.33)
PILs Recovery Rate Rider - effective until December 31, 2015	$/month	116.92
GEA Plan - Renewable Connection- Funding Rate Adder - effective until December 31, 2012	$/month	0.10
GEA Plan - Smart Grid - Funding Rate Adder - effective until December 31, 2012	$/month	0.83
Rate Rider for Recovery of Late Payment Litigation Costs - effective until April 30, 2012	$/month	53.31
Distribution Volumetric Rate	$/kW	3.3388
Rate Rider for Global Adjustment Sub-Account Disposition- effective until December 31, 2012	$/kW	(0.4403)
Rate Rider for Deferral/Variance Account- effective until December 31, 2012	$/kW	(0.5195)
LRAM/SSM Recovery- effective until December 31, 2015	$/kW	0.0061
Retail Transmission Rate – Network Service Rate -Interval Metered	$/kW	2.5335
Retail Transmission Rate – Line and Transformation Connection Service Rate -Interval Metered	$/kW	2.0359
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

Large Use	**Metrics**	**Rate**
Service Charge	$/month	907.62
Smart Meter Disposition Rate Rider - effective until December 31, 2012	$/month	(3.06)
Stranded Meter Cost Recovery Rate Rider - effective until December 31, 2015	$/month	0.73
Post Retairement actuarial Gain Disposition Rate Rider - effective until December 31, 2024	$/month	(151.18)
PILs Recovery Rate Rider - effective until December 31, 2015	$/month	381.57
GEA Plan - Renewable Connection- Funding Rate Adder - effective until December 31, 2012	$/month	0.10
GEA Plan - Smart Grid - Funding Rate Adder - effective until December 31, 2012	$/month	0.83
Rate Rider for Recovery of Late Payment Litigation Costs - effective until April 30, 2012	$/month	181.11
Distribution Volumetric Rate	$/kW	2.3247
Rate Rider for Global Adjustment Sub-Account Disposition- effective until December 31, 2012	$/kW	(0.5319)
Rate Rider for Deferral/Variance Account- effective until December 31, 2012	$/kW	(0.6221)
LRAM/SSM Recovery- effective until December 31, 2015	$/kW	0.0099
Retail Transmission Rate – Network Service Rate -Interval Metered	$/kW	3.0595
Retail Transmission Rate – Line and Transformation Connection Service Rate -Interval Metered	$/kW	2.4584
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load		
Service Charge (per connection)	$/month	5.84
Post Retairement actuarial Gain Disposition Rate Rider - effective until December 31, 2024	$/month	(0.05)
PILs Recovery Rate Rider - effective until December 31, 2015	$/month	0.13
GEA Plan - Renewable Connection- Funding Rate Adder - effective until December 31, 2012	$/month	0.10
GEA Plan - Smart Grid - Funding Rate Adder - effective until December 31, 2012	$/month	0.83
Rate Rider for Recovery of Late Payment Litigation Costs - effective until April 30, 2012	$/month	0.06
Distribution Volumetric Rate	$/kWh	0.0266
Rate Rider for Global Adjustment Sub-Account Disposition- effective until December 31, 2012	$/kWh	(0.0010)
Rate Rider for Deferral/Variance Account- effective until December 31, 2012	$/kWh	(0.0027)
LRAM/SSM Recovery- effective until December 31, 2015	$/kWh	0.0048
Retail Transmission Rate – Network Service Rate	$/kWh	0.0059
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0047
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting		
Service Charge (per connection)	$/month	6.96
Post Retairement actuarial Gain Disposition Rate Rider - effective until December 31, 2024	$/month	(0.11)
PILs Recovery Rate Rider - effective until December 31, 2012	$/month	0.27
GEA Plan - Renewable Connection- Funding Rate Adder - effective until December 31, 2012	$/month	0.10
GEA Plan - Smart Grid - Funding Rate Adder - effective until December 31, 2012	$/month	0.83
Rate Rider for Recovery of Late Payment Litigation Costs - effective until April 30, 2012	$/month	0.11
Distribution Volumetric Rate	$/kW	7.6916
Low Voltage Rate Adder - effective until December 31, 2015	$/kW	0.0112
Rate Rider for Global Adjustment Sub-Account Disposition- effective until December 31, 2012	$/kW	(0.0013)
Rate Rider for Deferral/Variance Account- effective until December 31, 2012	$/kW	(0.9850)
Retail Transmission Rate – Network Service Rate	$/kW	1.8700
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5026
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting		
Service Charge (per connection)	$/month	0.38
Post Retairement actuarial Gain Disposition Rate Rider - effective until December 31, 2024	$/month	(0.01)
PILs Recovery Rate Rider - effective until December 31, 2012	$/month	0.01
GEA Plan - Renewable Connection- Funding Rate Adder - effective until December 31, 2012	$/month	0.10
GEA Plan - Smart Grid - Funding Rate Adder - effective until December 31, 2012	$/month	0.83
Rate Rider for Recovery of Late Payment Litigation Costs - effective until April 30, 2012	$/month	0.01
Distribution Volumetric Rate	$/kW	9.2517
Low Voltage Rate Adder - effective until December 31, 2015	$/kW	0.0135
Rate Rider for Global Adjustment Sub-Account Disposition- effective until December 31, 2012	$/kW	(0.3328)
Rate Rider for Deferral/Variance Account- effective until December 31, 2012	$/kW	(2.7745)
Retail Transmission Rate – Network Service Rate	$/kW	2.2500
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.8079
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

microFIT Generator			
Service Charge		$	5.25
Specific Service Charges			
Customer Administration			
Arrears certificate	$		15.00
Returned cheque charge (plus bank charges)	$		8.55
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$		8.75
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$		10.00
Non-Payment of Account			0.00
Late Payment - per month	%		1.50
Late Payment - per annum	%		19.56
Collection of account charge - no disconnection	$		9.00
Disconnect/Reconnect at meter - during regular hours	$		20.00
Disconnect/Reconnect at meter - after regular hours	$		50.00
Disconnect/Reconnect at pole - during regular hours	$		50.00
Disconnect/Reconnect at pole - after regular hours	$		95.00
Other			0.00
Service call - customer-owned equipment	$		17.50
Service Call - Customer-owned Equipment - After Regular Hours	$		95.00
Specific Charge for Access to the Power Poles $/pole/year	$		22.35
			0.00
			0.00
Allowances			0.00
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW		(0.72)
Primary Metering Allowance for transformer losses - applied to measured demand and energy	%		(1.00)
			0.00
			0.00
Retail Service Charges (if applicable)			0.00
Retail Service Charges (if applicable)			0.00
Retail Service Charges refer to services provided by a distributor to retailers or customers related			0.00
to the supply of competitive electricity			0.00
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)			0.00
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			0.00
Settlement Code directly to retailers and customers, if not delivered electronically through the			0.00
Electronic Business Transaction (EBT) system, applied to the requesting party			0.00
Up to twice a year			no charge
More than twice a year, per request (plus incremental delivery costs)	$		2.00
			0.00
			0.00
Loss Factor			0.00
Total Loss factor - Secondary Metered Customer <5,000 kW			1.0209
Total Loss factor - Secondary Metered Customer > 5,000 kW			1.0160
Total Loss factor - Primary Metered Customer < 5,000 kW			1.0107
Total Loss factor - Primary Metered Customer > 5,000 kW			1.0059

SUMMARY OF UPDATED CUSTOMER BILL IMPACTS

(these Bill Impacts for Residential and GS< 50 kW contain all proposed rate adders, including 1562 PILs Disposition Rate Rider, and PP&E Disposition Rate Rider which could not be included in the OEB Revenue Requirement Work Form Sheet 10A and 10B because the model did not permit adding additional lines)

BILL IMPACTS - RESIDENTIAL

Consumption 800 kWh

Charge description	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	monthly	$13.4100	1	$ 13.41	$14.2900	1	$14.2900	$0.88	6.56%
Smart Meter Rate Adder	monthly	$1.1700	1	$ 1.17	$0.0000	1	$0.0000	($1.17)	-100.00%
Smart Meter Disposition Rate Rider	monthly	$0.0000	1	$ -	($0.1165)	1	($0.1165)	($0.12)	
Stranded Meter Cost Recovery Rate Rider	monthly	$0.0000	1	$ -	$0.7333	1	$0.7333	$0.73	
PRAGD Rate Rider	monthly	$0.0000	1	$ -	($0.1773)	1	($0.1773)	($0.18)	
PILs Recovery Rate Rider	monthly	$0.0000	1	$ -	$0.4475	1	$0.4475	$0.45	
GEA Plan - Renewable Connection - Funding Rate Adder	monthly	$0.0000	1	$ -	$0.1041	1	$0.1041	$0.10	
GEA Plan - Smart Grid - Funding Rate Adder	monthly				$0.8305	1	$0.8305		
Recovery of Late Payment Penalty Litigation Costs	monthly	$0.2200	1	$ 0.22	$0.2200	1	$0.2200	$0.00	0.00%
Distribution Volumetric Rate	per kWh	$0.0164	800	$ 13.12	$0.0174	800	$13.9200	$0.80	6.10%
Global Adjustment Sub-Account Disposition for non-RPP Customers	per kWh	$0.0006	800	$ 0.48	($0.0001)	800	($0.1002)	($0.58)	-120.88%
Deferral/Variance Account Disposition Rate Rider	per kWh	($0.0015)	800	-$ 1.20	($0.0020)	800	($1.5850)	($0.39)	32.08%
Incremental Capital Module Adder	per kWh	$0.0008	800	$ 0.64	$0.0000	800	$0.0000	($0.64)	-100.00%
Tax Change Rate Rider	per kWh	($0.0005)	800	-$ 0.40	$0.0000	800	$0.0000	$0.40	-100.00%
LRAM & SSM Rate Rider	per kWh	$0.0000	800	$ -	$0.0003	800	$0.2400	$0.24	
Low Voltage Rate Adder	per kWh	$0.0001	800	$ 0.08	$0.0000	800	$0.0000	($0.08)	-100.00%
Sub-Total A - Distribution				**$ 27.52**			**$ 28.57**	**$ 1.05**	**3.80%**
RTSR - Network	per kWh	$0.0062	832.32	$ 5.16	$ 0.0064	816.72	$ 5.23	$ 0.07	1.29%
RTSR - Line and Transformation Connection	per kWh	$0.0052	832.32	$ 4.33	$ 0.0053	816.72	$ 4.33	$ 0.00	0.01%
Sub-Total B - Delivery (including Sub-Total A)				**$ 37.01**			**$ 38.12**	**$ 1.11**	**3.01%**
Wholesale Market Service Charge (WMSC)	per kWh	$0.0052	832.32	$ 4.33	$ 0.0052	816.72	$ 4.25	($0.08)	-1.87%
Rural and Remote Rate Protection (RRRP)	per kWh	$0.0013	832.32	$ 1.08	$ 0.0013	816.72	$ 1.06	($0.02)	-1.87%
Special Purpose Charge		$0.0000	832.32	$ -	$ -	816.72	$ -	$0.00	
Standard Supply Service Charge	monthly	$0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	$0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$0.00	0.00%
Energy	per kWh	$0.0752	832.32	$ 62.55	$ 0.0752	816.72	$ 61.38	($1.17)	-1.87%
Total Bill (before Taxes)				**$ 110.82**			**$ 110.66**	**($0.16)**	**-0.14%**
HST		13%		$ 14.41	13%		$ 14.39	($0.02)	-0.14%
Total Bill (including Sub-total B)				**$ 125.22**			**$ 125.04**	**($0.18)**	**-0.14%**
Ontario Clean Energy Benefit (OCEB)		-10%		**-$ 12.52**	-10%		**-$ 12.50**	**$0.02**	**-0.16%**
Total Bill (including OCEB)				**$ 112.70**			**$ 112.54**	**($0.16)**	**-0.14%**
Loss Factor (%)	**Note 1**	4.04%			2.09%				

BILL IMPACTS – GENERAL SERVICE < 50 kW

Consumpt 2000 kWh

Charge description	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	monthly	$12.2600	1	$ 12.26	$15.0000	1	$15.00	$2.74	22.35%
Smart Meter Rate Adder	monthly	$1.1700	1	$ 1.17		1	$0.00	($1.17)	-100.00%
Smart Meter Disposition Rate Rider	monthly	$0.0000	1	$ -	($0.2463)	1	($0.25)	($0.25)	
Stranded Meter Cost Recovery Rate Rider	monthly	$0.0000	1	$ -	$0.7333	1	$0.73	$0.73	
PRAGD Rate Rider	monthly	$0.0000	1	$ -	($0.4994)	1	($0.50)	($0.50)	
PILs Recovery Rate Rider	monthly	$0.0000	1	$ -	$1.2604	1	$1.26	$1.26	
GEA -Renewable Connection- Funding Rate Adder	monthly	$0.0000	1	$ -	$0.1041	1	$0.10	$0.10	
GEA -Smart Grid- Funding Rate Adder	monthly				$0.8305	1	$0.83		
Recovery of Late Payment Penalty Litigation Costs	monthly	$0.5700	1	$ 0.57	$0.5700	1	$0.57	$0.00	0.00%
Distribution Volumetric Rate	per kWh	$0.0156	2000	$ 31.20	$0.0134	2000	$26.80	($4.40)	-14.10%
Global Adjustment Sub-Account Disposition for non-RPP Customers	per kWh	$0.0006	2000	$ 1.20	($0.0001)	2000	($0.29)	($1.49)	-123.98%
Deferral/Variance Account Disposition Rate Rider	per kWh	($0.0015)	2000	-$ 3.00	($0.0014)	2000	($2.73)	$0.27	-8.92%
Incremental Capital Module Adder	per kWh	$0.0004	2000	$ 0.80		2000	$0.00	($0.80)	-100.00%
Tax Change Rate Rider	per kWh	($0.0003)	2000	-$ 0.60		2000	$0.00	$0.60	-100.00%
LRAM & SSM Rate Rider	per kWh	$0.0000	2000	$ -	$0.0001	2000	$0.20	$0.20	
Low Voltage Rate Adder	per kWh	$0.0001	2000	$ 0.20	$0.0000	2000	$0.00	($0.20)	-100.00%
Volumetric Rate Adder(s)		$0.0000	2000	$ -		2000	$0.00	$0.00	
Volumetric Rate Rider(s)		$0.0000	2000	$ -		2000	$0.00	$0.00	
Sub-Total A - Distribution				**$ 43.80**			**$41.73**	**($2.07)**	**-4.72%**
RTSR - Network	per kWh	$ 0.0057	2080.8	$ 11.86	$ 0.0059	2041.8	$12.05	$0.19	1.57%
RTSR - Line and Transformation Connection	per kWh	$ 0.0046	2080.8	$ 9.57	$ 0.0047	2041.8	$9.60	$0.02	0.26%
Sub-Total B - Delivery (including Sub-Total A)				**$ 65.23**			**$63.38**	**($1.86)**	**-2.85%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2080.8	$ 10.82	$ 0.0052	2041.8	$10.62	($0.20)	-1.87%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2080.8	$ 2.71	$ 0.0013	2041.8	$2.65	($0.05)	-1.87%
Special Purpose Charge		$ -	2080.8	$ -		2041.8	$0.00	$0.00	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$0.25	$0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$14.00	$0.00	0.00%
Energy	per kWh	$ 0.0752	2080.8	$ 156.37	$ 0.0752	2041.8	$153.44	($2.93)	-1.87%
Total Bill (before Taxes)				**$ 249.38**			**$244.34**	**($5.04)**	**-2.02%**
HST		13%		$ 32.42	13%		$31.76	($0.66)	-2.02%
Total Bill (including Sub-total B)				**$ 281.80**			**$276.10**	**($5.70)**	**-2.02%**
Ontario Clean Energy Benefit (OCEB)		-10%		**-$ 28.18**	-10%		**($27.61)**	**$0.57**	**-2.02%**
Total Bill (including OCEB)				**$ 253.62**			**$248.49**	**($5.13)**	**-2.02%**

Note 1	4.04%	2.09%

ATTACHMENT 1
CAPITALIZATION POLICY

1. PURPOSE

1.01 This Statement of Policy provides guidance for the recording of the costs related to the acquisition or construction of distribution system assets, equipment, building, and other tangible assets. The control objectives addressed by this policy are to ensure that fixed assets are complete, exist, and are accurately recorded.

2. POLICY

2.01 All expenditures directly attributable to bringing an asset to the location and working condition for its intended use should be capitalized.

Examples of directly and "not directly" attributable costs are as follows:

Directly attributable:

- Employee costs and benefits incurred by employees working directly on construction or acquisition of asset
- Costs of site preparation
- Initial delivery and assembly
- Testing costs
- Professional fees

Not directly attributable:

- Administrative and other general overhead costs
- Feasibility studies
- Start-up or pre-opening costs

- Training costs
- Abnormal waste
- Costs incurred when construction is interrupted, unless certain criteria are met
- Cost of opening a new facility
- Relocation costs
- Costs incurred in using or redeploying an item

2.02 Costs attributed to administrative other, general overhead and training are prohibited from being capitalized.

The attaching listing provides a summary of all of the costs historically included in Guelph Hydro's burdenable (overhead) costs prior to the implementation to IFRS:

Payroll and Operations	**Stores Burden**
• Administration Expense	• Administration Expense
• Indirect Labour	• Building Maintenance
-Line Crew	• Depreciation
-Maintenance	• Salaries Management
-Metering	• Salaries – Bargaining Unit
-Customer Service	• Salaries – Temporary Staff
-Inspect/Engineering	• Employee Benefits
• Employee Benefits	• Equipment
• Small Tools	
• Clothing	

- Building Maintenance
- Insurance
- Outside Services – Subcontract
- Property Taxes
- Supervisory Salaries – Line Supervisors
- Supplies/Other
- Vehicle Expenses

Maintenance
- Freight
- Insurance
- Inventory Adjustment
- Licensing Fees
- Other
- Outside Services
- Property Taxes
- P.C. Expense
- Supplies
- Vehicles
- Work Order Charges

Fleet Burden
- Administration Expense
- Building and Operating Costs
- Depreciation
- Employee Benefits
- Equipment Maintenance
- Freight
- Fuel
- Insurance
- Licensing

Engineering Burden
- Administration Costs
- Employee Benefits
- Equipment Maintenance
- Freight
- Memberships
- Mini Computer
- Other
- Outside Services
- P.C. Expense
- Salary - Bargaining Unit

Included in the above listing are the following costs which are directly attributable to the construction of assets and therefore subject to capitalization.

- **Payroll and Operations Burden–** includes salaries, benefits, and other employment costs relating to supervisory staff, building maintenance, small tools, and supplies.
- **Engineering Burden –** includes salaries and benefits, office supplies, and information technology costs
- **Fleet Burden–** includes salaries and benefits, building operating costs, depreciation, fuel, maintenance and supplies

Included in the above listing are the following costs which have been removed since they are not directly attributable to the construction of assets:

- Non-productive time (training costs, safety meetings, adverse weather)
- Property taxes
- Supervisory salaries related to administrative functions
- Insurance
- Stores costs
- Information technology expenses
- Office equipment maintenance
- Freight
- Memberships
- Office supplies

2.03 Guelph Hydro uses a work order system to manage and record costs relating to the purchase and construction of property, plant, and equipment. The work order system is also used to track and record directly attributable expenses for capitalization such as labour costs, direct engineering, third party contractor costs, and vehicle costs. All employees who are directly involved in work order projects are required to record their time on timesheets, based on a series of time codes (regular, training, sick, vacation, etc.). This helps to ensure that only eligible costs are capitalized. Management in Engineering and Operations conduct regular reviews of work orders and time sheets to ensure the Corporation's capitalization policy is applied consistently and accurately For non-time sheet staff i.e. Operations Supervisory staff and Engineering staff, estimates are made of the time directly attributable to costs eligible for capitalization. These estimates reviewed annually by Management in Engineering and Operations.

3. SCOPE

3.01 This Statement of Policy applies to all employees engaged in the acquisition and recording of fixed assets.

4. RESPONSIBILITY

The Manager of Accounting and Accounting Supervisor are responsible for the identification and proper recording of fixed assets. Employees engaged in the acquisition of fixed assets are responsible for ensuring that the costs of acquisition are complete, exists and are accurate. The employee responsible for acquisition of the fixed asset is responsible for determining the useful life of the item.

Appendix 1

PP&E DEFERRAL ACCOUNT - Appendix 1

PP & E Values under CGAAP		Actual			Fcst
		2009	2010		2011
Opening NBV, Jan 1		86,624	90,620		90,452
Add:	Current year additions, net of disposals	15,156	7,877		24,178
Less:	Contributions & Grants	(4,336)	(3,440)		(2,679)
	Current year depreciation	(8,121)	(8,724)		(9,823)
Add:	Current year amortization of Contributions & Grants	1,297	1,414		1,521
	Acc'd depreciation adjustment re disposals	0	434		0
	Acc'd depreciation adjustment re stranded meters	0	2,271		0
Closing NBV, Dec 31		90,620	90,452		103,649

PP & E Values under MIFRS		Actual			Fcst
		2009	2010		2011
Opening NBV, Jan 1		86,624	90,620		90,602
Add:	Current year additions, net of disposals	15,156	5,185		21,981
Less:	Contributions and Grants	(4,336)	(3,440)		(2,679)
	Current year depreciation	(8,121)	(5,316)		(5,644)
Add:	Current year amortization of Contributions & Grants	1,297	848		915
	Acc'd depreciation adjustment re disposals	0	434		0
	Acc'd depreciation adjustment re stranded meters	0	2,271		0
Closing NBV, Dec 31		90,620	90,602		105,175
Difference in Closing net PP&E (CGAAP v. MIFRS)		0	150		1,526
Accumulated Difference not considering the removal of Contributions & Grant activity		0	150		1,526
			1		
Deferral Account - Rebasing in 2012 under MIFRS					
Opening Balance		0	A		150
Amount added in the year		0	150		1,376
		0	150		1,526
Amount of amortization, included in depreciation expense					
Closing balance		0	150		1,526

		2012	2013	2014	2015
	Amortization of Deferral Amount	382	382	382	382
	Return on Rate base at WACC - 2012 6.80%	104	104	104	104
	Amount included on Rev Requirement on Rebasing	485	485	485	485

Appendix 2

CGAAP vs. IFRS Comparison of Burdenable Items

Guelph Hydro
Labour Burden Expenses

	CGAAP	MIFRS
ADMINISTRATION		
OTHER	Y	N
CONFERENCES AND SEMINARS	Y	N
LODGING	Y	N
MEALS	Y	N
MILEAGE ALLOWANCE	Y	N
BUILDING OPER. ALLOCATION	Y	N
LINE CREW		
REGULAR	Y	Y
OVERTIME	Y	Y
OTHER	Y	Y
VACATION PAY	Y	Y
STATUTORY HOLIDAYS	Y	Y
SICK TIME	Y	Y
TRAINING	Y	N
SAFETY MEETINGS	Y	N
ADVERSE WEATHER	Y	N
MAINTENANCE		
REGULAR	Y	Y
OVERTIME	Y	Y
OTHER	Y	Y
VACATION PAY	Y	Y
STATUTORY HOLIDAYS	Y	Y
SICK TIME	Y	Y
TRAINING	Y	N
SAFETY MEETINGS	Y	N
ADVERSE WEATHER	Y	N
METERING		
REGULAR	Y	Y
OVERTIME	Y	Y
OTHER	Y	Y
VACATION PAY	Y	Y
STATUTORY HOLIDAYS	Y	Y
SICK TIME	Y	Y
TRAINING	Y	N
SAFETY MEETINGS	Y	N
INSPECTOR		
REGULAR	Y	Y
OVERTIME	Y	Y
OTHER	Y	Y
VACATION PAY	Y	Y
STATUTORY HOLIDAY	Y	Y
SICK TIME	Y	Y
TRAINING	Y	N
SAFETY MEETINGS	Y	N
BENEFITS		
BENEFITS	Y	Y
TRAINING	Y	N
INSURANCE	Y	N
PROPERTY TAXES	Y	N
OPERATIONS MANAGEMENT		
REGULAR	Y	Note 1
OVERTIME	Y	Note 1
VACATION PAY	Y	Note 1
STATUTORY HOLIDAYS	Y	Note 1
SICK TIME	Y	Note 1
TRAINING	Y	Note 1
SAFETY MEETINGS	Y	Note 1
OTHER	Y	Note 1
VEHICLES	Y	Y

NOTES:

Note 1 For Operations Management staff estimates are made of directly attributable capital costs based on each individual's time spent on capital projects.

Y Costs eligible to be capitalized under CGAAP and IFRS

N Costs not directly attributable to capital projects therefore not eligible to be capitalized under IFRS

Guelph Hydro
Stores Burden Expenses

	CGAAP	MIFRS
OTHER	Y	N
CONFERENCES AND SEMINARS	Y	N
MEALS	Y	N
MILEAGE ALLOWANCE	Y	N
BUILDING OPER. ALLOCATION	Y	N
DEPRECIATION	Y	N
BENEFITS		
BENEFITS	Y	N
TRAINING	Y	N
EQUIPMENT MAINTENANCE	Y	N
FREIGHT	Y	N
INSURANCE	Y	N
OTHER	Y	N
CABLE REEL	Y	N
UNIT PRICING	Y	N
LICENSING FEES	Y	N
OTHER	Y	N
OTHER	Y	N
SUB-CONTRACT	Y	N
PROPERTY TAXES	Y	N
OTHER	Y	N
SOFTWARE PURCHASES	Y	N
SALARIES AND WAGES		
Bargaining Unit		
REGULAR	Y	N
OVERTIME	Y	N
OTHER	Y	N
VACATION PAY	Y	N
STATUTORY HOLIDAYS	Y	N
SICK TIME	Y	N
TRAINING	Y	N
MEETINGS	Y	N
Management		
REGULAR	Y	N
OTHER	Y	N
VACATION PAY	Y	N
STATUTORY HOLIDAYS	Y	N
SICK TIME	Y	N
TRAINING	Y	N
Temporary		
REGULAR	Y	N
OTHER	Y	N
SMALL TOOLS	Y	N
VEHICLES	Y	N

NOTES:

Y Costs eligible to be capitalized under CGAAP and IFRS

N Costs not directly attributable to capital projects therefore not eligible to be capitalized under IFRS

Guelph Hydro
Fleet Burden Expenses

	CGAAP	MIFRS
ADMINISTRATION		
OTHER	Y	N
CONFERENCES AND SEMINARS	Y	N
LODGING	Y	N
MEALS	Y	N
BUILDING OPER. ALLOCATION	Y	N
DEPRECIATION	Y	Y
BENEFITS		
OTHER	Y	Y
EQUIPMENT MAINTENANCE	Y	N
TOOL REPAIR	Y	N
FREIGHT	Y	Y
FUEL	Y	Y
INSURANCE	Y	N
LICENSING FEES	Y	Y
OTHER	Y	Y
OUTSIDE SERVICES OTHER	Y	N
SMALL TOOL REPAIR	Y	N
SUB-CONTRACT	Y	Y
PROPERTY TAXES	Y	N
OTHER COMPUTER EXPENSES	Y	N
HARDWARE MAINTENANCE	Y	N
SOFTWARE PURCHASES	Y	N
SALARIES AND WAGES		
REGULAR	Y	Y
OVERTIME	Y	Y
OTHER	Y	Y
VACATION PAY	Y	Y
STATUTORY HOLIDAYS	Y	Y
SICK TIME	Y	Y
TRAINING	Y	N
MEETINGS	Y	N
OTHER - SUPPLIES	Y	Y
BUILDING	Y	Y
SMALL TOOLS	Y	Y
WORK ORDER CHARGES	Y	Y

NOTES:

Y Costs eligible to be capitalized under CGAAP and IFRS

N Costs not directly attributable to capital projects therefore not eligible to be capitalized under IFRS

Guelph Hydro
Engineering Burden Expenses

	CGAAP	MIFRS
ADMINISTRATION		
OTHER	Y	N
CONFERENCES AND SEMINARS	Y	N
LODGING	Y	N
MEALS	Y	N
MILEAGE ALLOWANCE	Y	N
BENEFITS		
OTHER	Y	Note 1
TRAINING	Y	N
OTHER	Y	N
PHOTOCOPIER	Y	N
FREIGHT	Y	N
OTHER	Y	N
G.I.S. DATABASE	Y	N
OTHER	Y	N
OUTSIDER SERVICES-OTHER	Y	N
ESA FEES	Y	N
OTHER	Y	N
HARDWARE MAINTENANCE	Y	N
PLOTTER/PRINTER EXPENSES	Y	N
SOFTWARE PURCHASES	Y	N
INTERNET	Y	N
SYSTEM OPTIMIZATION EXP	Y	N
SALARIES AND WAGES		
Bargaining Unit		
REGULAR	Y	Note 1
OVERTIME	Y	Note 1
OTHER	Y	Note 1
VACATION PAY	Y	Note 1
STATUTORY HOLIDAYS	Y	Note 1
SICK TIME	Y	Note 1
TRAINING	Y	N
MEETINGS	Y	Note 1
Management		
REGULAR	Y	Note 1
OVERTIME	Y	Note 1
OTHER	Y	Note 1
VACATION PAY	Y	Note 1
STATUTORY HOLIDAYS	Y	Note 1
SICK TIME	Y	Note 1
TRAINING	Y	N
SAFETY MEETINGS	Y	Note 1
Temporary		
REGULAR	Y	Note 1
OVERTIME	Y	Note 1
OTHER	Y	Note 1
VACATION PAY	Y	Note 1
STATUTORY HOLIDAYS	Y	Note 1
TRAINING	Y	N
SAFETY MEETINGS	Y	Note 1
SUPPLIES OTHER	Y	N
SMALL OFFICE EQUIPMENT	Y	N
SMALL TOOLS	Y	N
STATIONERY	Y	N
OFFICE	Y	N
COMPUTER	Y	N
TELEPHONE OTHER	Y	N
VEHICLES	Y	Y
WO CHARGES	Y	Y

NOTES:

Note 1	For Engineering staff estimates are made of directly attributable capital costs based on each individual's time spent on capital projects.
Y	Costs eligible to be capitalized under CGAAP and IFRS
N	Costs not directly attributable to capital projects therefore not eligible to be capitalized under IFRS

ATTACHMENT 2

COST ALLOCATION SHEETS O1 AND O2

2012 COST ALLOCATION
Guelph Hydro Electric Systems Inc.
EB-2011-0123
Wednesday, August 31, 2011
Ontario

Sheet O1 Revenue to Cost Summary Worksheet - Update to v 1.2

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

		Total	1	2	3	5	6	7	8	9
Rate Base Assets		**Total**	**Residential**	**General Service Less than 50 kW**	**General Service 50 to 999 kW**	**General Service Greater 1,000 to 4,999 kW**	**Large User**	**Street Lighting**	**Sentinel Lighting**	**Unmetered Scattered Load**
crev	Distribution Revenue at Existing Rates	$24,763,956	$13,913,205	$2,878,351	$4,237,461	$2,335,866	$1,111,116	$190,068	$3,829	$94,061
mi	Miscellaneous Revenue (mi)	$2,207,000	$1,449,059	$198,430	$184,878	$280,799	$46,249	$37,748	$375	$9,461
		Miscellaneous Revenue Input equals Output								
	Total Revenue at Existing Rates	$26,970,956	$15,362,263	$3,076,781	$4,422,339	$2,616,666	$1,157,365	$227,816	$4,204	$103,522
	Factor required to recover deficiency (1 + D)	1.0654								
	Distribution Revenue at Status Quo Rates	$26,383,971	$14,823,382	$3,066,648	$4,514,668	$2,488,675	$1,183,803	$202,502	$4,079	$100,214
	Miscellaneous Revenue (mi)	$2,207,000	$1,449,059	$198,430	$184,878	$280,799	$46,249	$37,748	$375	$9,461
	Total Revenue at Status Quo Rates	$28,590,971	$16,272,441	$3,265,078	$4,699,546	$2,769,474	$1,230,052	$240,250	$4,454	$109,675
	Expenses									
di	Distribution Costs (di)	$5,438,756	$3,139,243	$374,930	$480,712	$1,116,123	$187,032	$117,639	$1,147	$21,931
cu	Customer Related Costs (cu)	$3,098,684	$2,279,478	$358,163	$389,391	$45,486	$11,700	$56	$179	$14,232
ad	General and Administration (ad)	$5,788,560	$3,667,906	$496,533	$590,479	$791,848	$136,457	$80,000	$899	$24,440
dep	Depreciation and Amortization (dep)	$4,659,567	$2,629,282	$390,034	$487,250	$861,694	$201,152	$76,554	$695	$12,906
INPUT	PILs (INPUT)	$73,246	$37,453	$5,874	$9,024	$15,215	$4,317	$1,162	$10	$192
INT	Interest	$4,249,475	$2,172,885	$340,773	$523,559	$882,697	$250,443	$67,393	$603	$11,122
	Total Expenses	$23,308,287	$13,926,246	$1,966,306	$2,480,415	$3,713,062	$791,101	$342,802	$3,532	$84,822
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0	$0	$0
	14,823,382.1124									
NI	Allocated Net Income (NI)	$5,282,683	$2,701,195	$423,627	$650,856	$1,097,314	$311,335	$83,779	$749	$13,826
	Revenue Requirement (includes NI)	$28,590,971	$16,627,442	$2,389,933	$3,131,272	$4,810,377	$1,102,436	$426,581	$4,281	$98,649
	$0	Revenue Requirement Input equals Output								

Rate Base Assets		Total	1 Residential	2 General Service Less than 50 kW	3 General Service 50 to 999 kW	5 General Service Greater 1,000 to 4,999 kW	6 Large User	7 Street Lighting	8 Sentinel Lighting	9 Unmetered Scattered Load
	Rate Base Calculation									
	Net Assets									
dp	Distribution Plant - Gross	$202,037,782	$109,284,113	$15,403,096	$21,325,071	$42,002,869	$9,691,395	$3,686,218	$33,051	$611,970
gp	General Plant - Gross	$14,784,263	$7,810,192	$1,135,422	$1,643,775	$3,109,057	$785,806	$255,485	$2,288	$42,238
accum dep	Accumulated Depreciation	($62,674,451)	($34,994,104)	($4,803,113)	($6,200,809)	($12,744,071)	($2,487,740)	($1,229,256)	($10,987)	($204,373)
co	Capital Contribution	($39,126,611)	($23,190,651)	($2,530,860)	($2,664,796)	($8,461,226)	($1,243,408)	($880,272)	($7,965)	($147,434)
	Total Net Plant	$115,020,983	$58,909,550	$9,204,545	$14,103,241	$23,906,629	$6,746,054	$1,832,175	$16,388	$302,402
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$153,524,605	$34,704,882	$13,629,071	$36,609,349	$42,605,403	$24,867,916	$895,649	$8,129	$204,206
	OM&A Expenses	$14,326,000	$9,086,626	$1,229,626	$1,460,582	$1,953,456	$335,189	$197,694	$2,224	$60,603
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$167,850,605*	*$43,791,508*	*$14,858,696*	*$38,069,930*	*$44,558,860*	*$25,203,106*	*$1,093,344*	*$10,353*	*$264,808*
	Working Capital	$25,177,591	$6,568,726	$2,228,804	$5,710,490	$6,683,829	$3,780,466	$164,002	$1,553	$39,721
	Total Rate Base	$140,198,574	$65,478,276	$11,433,349	$19,813,731	$30,590,458	$10,526,520	$1,996,177	$17,941	$342,123
		Rate Base Input equals Output								
	Equity Component of Rate Base	$56,079,430	$26,191,310	$4,573,340	$7,925,492	$12,236,183	$4,210,608	$798,471	$7,176	$136,849
	Net Income on Allocated Assets	$5,282,683	$2,346,194	$1,298,772	$2,219,131	($943,588)	$438,951	($102,552)	$922	$24,853
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Net Income	$5,282,683	$2,346,194	$1,298,772	$2,219,131	($943,588)	$438,951	($102,552)	$922	$24,853
	RATIOS ANALYSIS									
	REVENUE TO EXPENSES STATUS QUO%	100.00%	97.86%	136.62%	150.08%	57.57%	111.58%	56.32%	104.04%	111.18%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($1,620,015)	($1,265,179)	$686,848	$1,291,067	($2,193,711)	$54,929	($198,765)	($77)	$4,873
		Deficiency Input equals Output								
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	$0	($355,001)	$875,145	$1,568,275	($2,040,903)	$127,616	($186,331)	$173	$11,026
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.42%	8.96%	28.40%	28.00%	-7.71%	10.42%	-12.84%	12.85%	18.16%

2012 COST ALLOCATION
Guelph Hydro Electric Systems Inc.
EB-2011-0123
Wednesday, August 31, 2011

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Update to v 1.2

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	5	6	7	8	9
	Residential	General Service Less than 50 kW	General Service 50 to 999 kW	General Service Greater 1,000 to 4,999 kW	Large User	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
Customer Unit Cost per month - Avoided Cost	$5.49	$11.98	$72.57	$106.61	$307.47	$0.00	$0.52	$1.83
Customer Unit Cost per month - Directly Related	$7.92	$16.88	$107.22	$164.10	$471.41	$0.00	$0.87	$3.07
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$16.65	$23.24	$123.88	$183.07	$505.54	$6.05	$8.63	$9.05
Existing Approved Fixed Charge	$13.41	$12.26	$230.69	$620.07	$907.62	$0.23	$6.53	$5.48

Information to be Used to Allocate PILs, ROD, ROE and A&G

		1	2	3	5	6	7	8	9
	Total	Residential	General Service Less than 50 kW	General Service 50 to 999 kW	General Service Greater 1,000 to 4,999 kW	Large User	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
General Plant - Gross Assets	$14,784,263	$7,810,192	$1,135,422	$1,643,775	$3,109,057	$785,806	$255,485	$2,288	$42,238
General Plant - Accumulated Depreciation	($9,128,598)	($4,822,432)	($701,071)	($1,014,955)	($1,919,699)	($485,199)	($157,750)	($1,413)	($26,080)
General Plant - Net Fixed Assets	$5,655,665	$2,987,760	$434,351	$628,820	$1,189,358	$300,607	$97,735	$875	$16,158
General Plant - Depreciation	$46,224	$24,419	$3,550	$5,139	$9,721	$2,457	$799	$7	$132
Total Net Fixed Assets Excluding General Plant	$109,365,318	$55,921,790	$8,770,194	$13,474,421	$22,717,271	$6,445,447	$1,734,440	$15,512	$286,243
Total Administration and General Expense	$5,788,560	$3,667,906	$496,533	$590,479	$791,848	$136,457	$80,000	$899	$24,440
Total O&M	$8,537,440	$5,418,720	$733,093	$870,103	$1,161,608	$198,733	$117,695	$1,325	$36,163

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

USoA Account #	Accounts	Total	1 Residential	2 General Service Less than 50 kW	3 General Service 50 to 999 kW	5 General Service Greater 1,000 to 4,999 kW	6 Large User	7 Street Lighting	8 Sentinel Lighting	9 Unmetered Scattered Load	
	Distribution Plant										
1860	Meters	$15,037,608	$11,132,106	$2,313,411	$1,428,484	$129,493	$34,114	$0	$0	$0	CWMC
	Accumulated Amortization										
	Accum. Amortization of Electric Utility Plant - Meters only	($3,876,105)	($2,869,419)	($596,307)	($368,207)	($33,378)	($8,793)	$0	$0	$0	
	Meter Net Fixed Assets	**$11,161,504**	**$8,262,686**	**$1,717,105**	**$1,060,277**	**$96,115**	**$25,321**	**$0**	**$0**	**$0**	
	Misc Revenue										
4082	Retail Services Revenues	($8,250)	($5,233)	($708)	($841)	($1,125)	($193)	($114)	($1)	($35)	CWNB
4084	Service Transaction Requests (STR) Revenues	($7,600)	($4,820)	($652)	($775)	($1,036)	($178)	($105)	($1)	($32)	CWNB
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	NFA
4225	Late Payment Charges	($127,572)	($91,852)	($30,617)	($5,103)	$0	$0	$0	$0	$0	LPHA
	Sub-total	*($143,422)*	*($101,905)*	*($31,978)*	*($6,719)*	*($2,161)*	*($371)*	*($219)*	*($2)*	*($67)*	
	Operation										
5065	Meter Expense	$358,313	$265,253	$55,123	$34,038	$3,086	$813	$0	$0	$0	CWMC
5070	Customer Premises - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	CCA
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	CCA
	Sub-total	*$358,313*	*$265,253*	*$55,123*	*$34,038*	*$3,086*	*$813*	*$0*	*$0*	*$0*	
	Maintenance										
5175	Maintenance of Meters	$56,075	$41,511	$8,627	$5,327	$483	$127	$0	$0	$0	1860
	Billing and Collection										
5310	Meter Reading Expense	$294,040	$198,417	$15,708	$52,593	$20,727	$6,595	$0	$0	$0	CWMR
5315	Customer Billing	$1,932,590	$1,432,764	$226,845	$238,629	$18,280	$3,593	$48	$154	$12,277	CWNB
5320	Collecting	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
5325	Collecting- Cash Over and Short	$50	$37	$6	$6	$0	$0	$0	$0	$0	CWNB
5330	Collection Charges	$93,351	$69,208	$10,957	$11,527	$883	$174	$2	$7	$593	CWNB
	Sub-total	$2,320,031	$1,700,426	$253,516	$302,754	$39,890	$10,362	$50	$162	$12,870	
	Total Operation, Maintenance and Billing	$2,734,419	$2,007,191	$317,266	$342,119	$43,459	$11,302	$50	$162	$12,870	
	Amortization Expense - Meters	$750,635	$555,683	$115,479	$71,306	$6,464	$1,703	$0	$0	$0	
	Allocated PILs	$7,105	$5,253	$1,096	$678	$61	$16	$0	$0	$0	
	Allocated Debt Return	$412,191	$304,770	$63,571	$39,361	$3,549	$940	$0	$0	$0	
	Allocated Equity Return	$512,410	$378,871	$79,028	$48,931	$4,412	$1,169	$0	$0	$0	
	Total	**$4,273,337**	**$3,149,863**	**$544,461**	**$495,677**	**$55,783**	**$14,759**	**($168)**	**$159**	**$12,803**	

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

USoA Account #	Accounts	Total	1 Residential	2 General Service Less than 50 kW	3 General Service 50 to 999 kW	5 General Service Greater 1,000 to 4,999 kW	6 Large User	7 Street Lighting	8 Sentinel Lighting	9 Unmetered Scattered Load	
	Distribution Plant										
1860	Meters	$15,037,608	$11,132,106	$2,313,411	$1,428,484	$129,493	$34,114	$0	$0	$0	CWMC
	Accumulated Amortization										
	Accum. Amortization of Electric Utility Plant - Meters only	($3,876,105)	($2,869,419)	($596,307)	($368,207)	($33,378)	($8,793)	$0	$0	$0	
	Meter Net Fixed Assets	$11,161,504	$8,262,686	$1,717,105	$1,060,277	$96,115	$25,321	$0	$0	$0	
	Allocated General Plant Net Fixed Assets	$582,189	$441,454	$85,041	$49,481	$5,032	$1,181	$0	$0	$0	
	Meter Net Fixed Assets Including General Plant	$11,743,693	$8,704,141	$1,802,146	$1,109,758	$101,147	$26,501	$0	$0	$0	
	Misc Revenue										
4082	Retail Services Revenues	($8,250)	($5,233)	($708)	($841)	($1,125)	($193)	($114)	($1)	($35)	CWNB
4084	Service Transaction Requests (STR) Revenues	($7,600)	($4,820)	($652)	($775)	($1,036)	($178)	($105)	($1)	($32)	CWNB
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	NFA
4225	Late Payment Charges	($127,572)	($91,852)	($30,617)	($5,103)	$0	$0	$0	$0	$0	LPHA
	Sub-total	*($143,422)*	*($101,905)*	*($31,978)*	*($6,719)*	*($2,161)*	*($371)*	*($219)*	*($2)*	*($67)*	
	Operation										
5065	Meter Expense	$358,313	$265,253	$55,123	$34,038	$3,086	$813	$0	$0	$0	CWMC
5070	Customer Premises - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	CCA
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	CCA
	Sub-total	*$358,313*	*$265,253*	*$55,123*	*$34,038*	*$3,086*	*$813*	*$0*	*$0*	*$0*	
	Maintenance										
5175	Maintenance of Meters	$56,075	$41,511	$8,627	$5,327	$483	$127	$0	$0	$0	1860
	Billing and Collection										
5310	Meter Reading Expense	$294,040	$198,417	$15,708	$52,593	$20,727	$6,595	$0	$0	$0	CWMR
5315	Customer Billing	$1,932,590	$1,432,764	$226,845	$238,629	$18,280	$3,593	$48	$154	$12,277	CWNB
5320	Collecting	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
5325	Collecting- Cash Over and Short	$50	$37	$6	$6	$0	$0	$0	$0	$0	CWNB
5330	Collection Charges	$93,351	$69,208	$10,957	$11,527	$883	$174	$2	$7	$593	CWNB
	Sub-total	*$2,320,031*	*$1,700,426*	*$253,516*	*$302,754*	*$39,890*	*$10,362*	*$50*	*$162*	*$12,870*	
	Total Operation, Maintenance and Billing	$2,734,419	$2,007,191	$317,266	$342,119	$43,459	$11,302	$50	$162	$12,870	
	Amortization Expense - Meters	$750,635	$555,683	$115,479	$71,306	$6,464	$1,703	$0	$0	$0	
	Amortization Expense - General Plant assigned to Meters	*$4,758*	*$3,608*	*$695*	*$404*	*$41*	*$10*	*$0*	*$0*	*$0*	
	Admin and General	$1,851,946	$1,358,658	$214,888	$232,172	$29,625	$7,760	$34	$110	$8,698	
	Allocated PILs	$7,475	$5,534	$1,150	$710	$64	$17	$0	$0	$0	
	Allocated Debt Return	$433,689	$321,053	$66,719	$41,198	$3,735	$984	$0	$0	$0	
	Allocated Equity Return	$539,135	$399,113	$82,941	$51,215	$4,643	$1,223	$0	$0	$0	
	Total	**$6,178,635**	**$4,548,935**	**$767,161**	**$732,405**	**$85,869**	**$22,628**	**($134)**	**$269**	**$21,502**	

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	1 Residential	2 General Service Less than 50 kW	3 General Service 50 to 999 kW	5 General Service Greater 1,000 to 4,999 kW	6 Large User	7 Street Lighting	8 Sentinel Lighting	9 Unmetered Scattered Load	
	Distribution Plant										
1565	Conservation and Demand Management Expenditures and Recoveries	$51,396	$32,621	$4,413	$5,238	$6,993	$1,196	$709	$8	$218	CDMPP
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	#N/A
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	BCP
1830-4	Poles, Towers and Fixtures - Primary	$5,613,207	$4,773,629	$377,896	$56,790	$4,350	$399	$339,424	$2,570	$58,149	PNCP
1830-5	Poles, Towers and Fixtures - Secondary	$1,685,203	$1,532,494	$24,249	$0	$0	$0	$108,967	$825	$18,668	SNCP
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	#N/A
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	BCP
1835-4	Overhead Conductors and Devices - Primary	$4,565,412	$3,882,554	$307,356	$46,189	$3,538	$325	$276,065	$2,090	$47,294	PNCP
1835-5	Overhead Conductors and Devices - Secondary	$1,370,633	$1,246,429	$19,723	$0	$0	$0	$88,626	$671	$15,183	SNCP
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	#N/A
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	BCP
1840-4	Underground Conduit - Primary	$7,245,620	$6,161,879	$487,795	$73,305	$5,615	$515	$438,135	$3,318	$75,059	PNCP
1840-5	Underground Conduit - Secondary	$5,206,039	$4,734,281	$74,913	$0	$0	$0	$336,627	$2,549	$57,669	SNCP
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	#N/A
											BCP
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	
1845-4	Underground Conductors and Devices - Primary	$6,913,898	$5,879,773	$465,462	$69,949	$5,358	$492	$418,076	$3,166	$71,623	PNCP
											SNCP
1845-5	Underground Conductors and Devices - Secondary	$4,967,693	$4,517,534	$71,483	$0	$0	$0	$321,215	$2,432	$55,029	
1850	Line Transformers	$6,915,973	$5,890,761	$466,332	$65,095	$0	$0	$418,857	$3,172	$71,757	LTNCP
1855	Services	$7,592,119	$7,076,866	$223,961	$0	$0	$0	$201,278	$3,810	$86,205	CWCS
1860	Meters	$15,037,608	$11,132,106	$2,313,411	$1,428,484	$129,493	$34,114	$0	$0	$0	CWMC
1880	IFRS Placeholder Asset Account	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
	Sub-total	*$67,164,801*	*$56,860,926*	*$4,836,993*	*$1,745,050*	*$155,348*	*$37,040*	*$2,947,978*	*$24,612*	*$556,854*	
	Accumulated Amortization										
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	($32,860,567)	($28,317,097)	($1,980,750)	($542,599)	($50,858)	($10,949)	($1,634,817)	($13,692)	($309,806)	
	Customer Related Net Fixed Assets	$34,304,234	$28,543,828	$2,856,243	$1,202,451	$104,491	$26,092	$1,313,161	$10,920	$247,049	
	Allocated General Plant Net Fixed Assets	$1,817,843	$1,525,025	$141,458	$56,116	$5,471	$1,217	$73,996	$616	$13,946	
	Customer Related NFA Including General Plant	$36,122,077	$30,068,853	$2,997,701	$1,258,567	$109,961	$27,309	$1,387,157	$11,536	$260,994	
	Misc Revenue										
4082	Retail Services Revenues	($8,250)	($5,233)	($708)	($841)	($1,125)	($193)	($114)	($1)	($35)	CWNB
4084	Service Transaction Requests (STR) Revenues	($7,600)	($4,820)	($652)	($775)	($1,036)	($178)	($105)	($1)	($32)	CWNB
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	NFA
4225	Late Payment Charges	($127,572)	($91,852)	($30,617)	($5,103)	$0	$0	$0	$0	$0	LPHA
4235	Miscellaneous Service Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
	Sub-total	*($143,422)*	*($101,905)*	*($31,978)*	*($6,719)*	*($2,161)*	*($371)*	*($219)*	*($2)*	*($67)*	

	Operating and Maintenance										
5005	Operation Supervision and Engineering	$757,882	$665,037	$36,663	$4,531	$275	$25	$42,893	$358	$8,101	1815-1855
5010	Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0	$0	1815-1855
5020	Overhead Distribution Lines and Feeders - Operation Labour	$4,253	$3,674	$234	$33	$3	$0	$261	$2	$45	1830 & 1835
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$12,240	$10,576	$674	$95	$7	$1	$752	$6	$129	1830 & 1835
5035	Overhead Distribution Transformers- Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	1850
5040	Underground Distribution Lines and Feeders - Operation Labour	$89,205	$78,061	$4,031	$525	$40	$4	$5,550	$42	$951	1840 & 1845
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$2,603	$2,277	$118	$15	$1	$0	$162	$1	$28	1840 & 1845
5055	Underground Distribution Transformers - Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	1850
5065	Meter Expense	$358,313	$265,253	$55,123	$34,038	$3,086	$813	$0	$0	$0	CWMC
5070	Customer Premises - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	CCA
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	CCA
5085	Miscellaneous Distribution Expense	$220,344	$193,351	$10,659	$1,317	$80	$7	$12,471	$104	$2,355	1815-1855
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	1840 & 1845
5095	Overhead Distribution Lines and Feeders - Rental Paid	$2,700	$2,333	$149	$21	$2	$0	$166	$1	$28	1830 & 1835
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	O&M
5105	Maintenance Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	1815-1855
5120	Maintenance of Poles, Towers and Fixtures	$29,070	$25,118	$1,602	$226	$17	$2	$1,786	$14	$306	1830
5125	Maintenance of Overhead Conductors and Devices	$138,795	$119,925	$7,648	$1,080	$83	$8	$8,527	$65	$1,461	1835
5130	Maintenance of Overhead Services	$267,900	$249,718	$7,903	$0	$0	$0	$7,102	$134	$3,042	1855
5135	Overhead Distribution Lines and Feeders - Right of Way	$44,400	$38,363	$2,446	$345	$26	$2	$2,728	$21	$467	1830 & 1835
5145	Maintenance of Underground Conduit	$25,080	$21,947	$1,133	$148	$11	$1	$1,561	$12	$267	1840
5150	Maintenance of Underground Conductors and Devices	$59,280	$51,875	$2,679	$349	$27	$2	$3,688	$28	$632	1845
5155	Maintenance of Underground Services	$168,150	$156,738	$4,960	$0	$0	$0	$4,458	$84	$1,909	1855
5160	Maintenance of Line Transformers	$126,420	$107,680	$8,524	$1,190	$0	$0	$7,656	$58	$1,312	1850
5175	Maintenance of Meters	$56,075	$41,511	$8,627	$5,327	$483	$127	$0	$0	$0	1860
	Sub-total	*$2,362,709*	*$2,033,438*	*$153,174*	*$49,241*	*$4,140*	*$993*	*$99,762*	*$930*	*$21,033*	
	Billing and Collection										
5305	Supervision	$210,865	$156,329	$24,751	$26,037	$1,995	$392	$5	$17	$1,340	CWNB
5310	Meter Reading Expense	$294,040	$198,417	$15,708	$52,593	$20,727	$6,595	$0	$0	$0	CWMR
5315	Customer Billing	$1,932,590	$1,432,764	$226,845	$238,629	$18,280	$3,593	$48	$154	$12,277	CWNB
5320	Collecting	$0	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
5325	Collecting- Cash Over and Short	$50	$37	$6	$6	$0	$0	$0	$0	$0	CWNB
5330	Collection Charges	$93,351	$69,208	$10,957	$11,527	$883	$174	$2	$7	$593	CWNB
5335	Bad Debt Expense	$150,000	$113,437	$15,747	$20,815	$0	$0	$0	$0	$0	BDHA
5340	Miscellaneous Customer Accounts Expenses	$3,400	$2,521	$399	$420	$32	$6	$0	$0	$22	CWNB
	Sub-total	*$2,684,296*	*$1,972,713*	*$294,413*	*$350,027*	*$41,917*	*$10,760*	*$56*	*$179*	*$14,232*	
	Sub Total Operating, Maintenance and Biling	*$5,047,005*	*$4,006,151*	*$447,587*	*$399,267*	*$46,057*	*$11,753*	*$99,817*	*$1,109*	*$35,265*	
	Amortization Expense - Customer Related	$1,857,323	$1,520,418	$169,335	$80,946	$11,469	$2,530	$60,479	$513	$11,633	
	Amortization Expense - General Plant assigned to Meters	$14,857	$12,464	$1,156	$459	$45	$10	$605	$5	$114	
	Admin and General	$3,417,755	$2,711,745	$303,156	$270,955	$31,396	$8,070	$67,848	$752	$23,833	
	Allocated PILs	$22,975	$19,117	$1,913	$805	$70	$17	$879	$7	$165	
	Allocated Debt Return	$1,332,918	$1,109,093	$110,982	$46,722	$4,060	$1,014	$51,024	$424	$9,599	
	Allocated Equity Return	$1,657,001	$1,378,755	$137,965	$58,082	$5,047	$1,260	$63,430	$527	$11,933	
	PLCC Adjustment for Line Transformer	$197,137	$167,909	$13,291	$1,856	$0	$0	$11,946	$90	$2,045	
	PLCC Adjustment for Primary Costs	$239,075	$203,085	$16,275	$2,478	$190	$17	$14,446	$109	$2,474	
	PLCC Adjustment for Secondary Costs	$873,019	$723,016	$54,356	$0	$0	$0	$70,552	$466	$24,629	
	Total	$11,897,181	**$9,561,827**	**$1,056,194**	**$846,184**	**$95,793**	**$24,266**	**$246,920**	**$2,669**	**$63,327**	

Below: Grouping to avoid disclosure

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

Accounts	Total	Residential	General Service Less than 50 kW	General Service 50 to 999 kW	General Service Greater 1,000 to 4,999 kW	Large User	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
Distribution Plant									
CWMC	$ 15,037,608	$ 11,132,106	$ 2,313,411	$ 1,428,484	$ 129,493	$ 34,114	$ -	$ -	$ -
Accumulated Amortization									
Accum. Amortization of Electric Utility Plant - Meters only	$ (3,876,105)	$ (2,869,419)	$ (596,307)	$ (368,207)	$ (33,378)	$ (8,793)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 11,161,504	$ 8,262,686	$ 1,717,105	$ 1,060,277	$ 96,115	$ 25,321	$ -	$ -	$ -
Misc Revenue									
CWNB	$ (15,850)	$ (10,053)	$ (1,360)	$ (1,616)	$ (2,161)	$ (371)	$ (219)	$ (2)	$ (67)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (127,572)	$ (91,852)	$ (30,617)	$ (5,103)	$ -	$ -	$ -	$ -	$ -
Sub-total	$ (143,422)	$ (101,905)	$ (31,978)	$ (6,719)	$ (2,161)	$ (371)	$ (219)	$ (2)	$ (67)
Operation									
CWMC	$ 358,313	$ 265,253	$ 55,123	$ 34,038	$ 3,086	$ 813	$ -	$ -	$ -
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	$ 358,313	$ 265,253	$ 55,123	$ 34,038	$ 3,086	$ 813	$ -	$ -	$ -
Maintenance									
1860	$ 56,075	$ 41,511	$ 8,627	$ 5,327	$ 483	$ 127	$ -	$ -	$ -
Billing and Collection									
CWMR	$ 294,040	$ 198,417	$ 15,708	$ 52,593	$ 20,727	$ 6,595	$ -	$ -	$ -
CWNB	$ 2,025,991	$ 1,502,009	$ 237,808	$ 250,162	$ 19,163	$ 3,767	$ 50	$ 162	$ 12,870
Sub-total	$ 2,320,031	$ 1,700,426	$ 253,516	$ 302,754	$ 39,890	$ 10,362	$ 50	$ 162	$ 12,870
Total Operation, Maintenance and Billing	$ 2,734,419	$ 2,007,191	$ 317,266	$ 342,119	$ 43,459	$ 11,302	$ 50	$ 162	$ 12,870
Amortization Expense - Meters	$ 750,635	$ 555,683	$ 115,479	$ 71,306	$ 6,464	$ 1,703	$ -	$ -	$ -
Allocated PILs	$ 7,105	$ 5,253	$ 1,096	$ 678	$ 61	$ 16	$ -	$ -	$ -
Allocated Debt Return	$ 412,191	$ 304,770	$ 63,571	$ 39,361	$ 3,549	$ 940	$ -	$ -	$ -
Allocated Equity Return	$ 512,410	$ 378,871	$ 79,028	$ 48,931	$ 4,412	$ 1,169	$ -	$ -	$ -
Total	**$ 4,273,337**	**$ 3,149,863**	**$ 544,461**	**$ 495,677**	**$ 55,783**	**$ 14,759**	**$ (168)**	**$ 159**	**$ 12,803**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

Accounts	Total	Residential	General Service Less than 50 kW	General Service 50 to 999 kW	General Service Greater 1,000 to 4,999 kW	Large User	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
Distribution Plant									
CWMC	$ 15,037,608	$ 11,132,106	$ 2,313,411	$ 1,428,484	$ 129,493	$ 34,114	$ -	$ -	$ -
Accumulated Amortization									
Accum. Amortization of Electric Utility Plant - Meters only	$ (3,876,105)	$ (2,869,419)	$ (596,307)	$ (368,207)	$ (33,378)	$ (8,793)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 11,161,504	$ 8,262,686	$ 1,717,105	$ 1,060,277	$ 96,115	$ 25,321	$ -	$ -	$ -
Allocated General Plant Net Fixed Assets	$ 582,189	$ 441,454	$ 85,041	$ 49,481	$ 5,032	$ 1,181	$ -	$ -	$ -
Meter Net Fixed Assets Including General Plant	$ 11,743,693	$ 8,704,141	$ 1,802,146	$ 1,109,758	$ 101,147	$ 26,501	$ -	$ -	$ -
Misc Revenue									
CWNB	$ (15,850)	$ (10,053)	$ (1,360)	$ (1,616)	$ (2,161)	$ (371)	$ (219)	$ (2)	$ (67)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (127,572)	$ (91,852)	$ (30,617)	$ (5,103)	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ (143,422)*	*$ (101,905)*	*$ (31,978)*	*$ (6,719)*	*$ (2,161)*	*$ (371)*	*$ (219)*	*$ (2)*	*$ (67)*
Operation									
CWMC	$ 358,313	$ 265,253	$ 55,123	$ 34,038	$ 3,086	$ 813	$ -	$ -	$ -
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ 358,313*	*$ 265,253*	*$ 55,123*	*$ 34,038*	*$ 3,086*	*$ 813*	*$ -*	*$ -*	*$ -*
Maintenance									
1860	$ 56,075	$ 41,511	$ 8,627	$ 5,327	$ 483	$ 127	$ -	$ -	$ -
Billing and Collection									
CWMR	$ 294,040	$ 198,417	$ 15,708	$ 52,593	$ 20,727	$ 6,595	$ -	$ -	$ -
CWNB	$ 2,025,991	$ 1,502,009	$ 237,808	$ 250,162	$ 19,163	$ 3,767	$ 50	$ 162	$ 12,870
Sub-total	*$ 2,320,031*	*$ 1,700,426*	*$ 253,516*	*$ 302,754*	*$ 39,890*	*$ 10,362*	*$ 50*	*$ 162*	*$ 12,870*
Total Operation, Maintenance and Billing	$ 2,734,419	$ 2,007,191	$ 317,266	$ 342,119	$ 43,459	$ 11,302	$ 50	$ 162	$ 12,870
Amortization Expense - Meters	$ 750,635	$ 555,683	$ 115,479	$ 71,306	$ 6,464	$ 1,703	$ -	$ -	$ -
Amortization Expense - General Plant assigned to Meters	$ 4,758	$ 3,608	$ 695	$ 404	$ 41	$ 10	$ -	$ -	$ -
Admin and General	$ 1,851,946	$ 1,358,658	$ 214,888	$ 232,172	$ 29,625	$ 7,760	$ 34	$ 110	$ 8,698
Allocated PILs	$ 7,475	$ 5,534	$ 1,150	$ 710	$ 64	$ 17	$ -	$ -	$ -
Allocated Debt Return	$ 433,689	$ 321,053	$ 66,719	$ 41,198	$ 3,735	$ 984	$ -	$ -	$ -
Allocated Equity Return	$ 539,135	$ 399,113	$ 82,941	$ 51,215	$ 4,643	$ 1,223	$ -	$ -	$ -
Total	**$ 6,178,635**	**$ 4,548,935**	**$ 767,161**	**$ 732,405**	**$ 85,869**	**$ 22,628**	**$ (134)**	**$ 269**	**$ 21,502**

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	Residential	General Service Less than 50 kW	General Service 50 to 999 kW	General Service Greater 1,000 to 4,999 kW	Large User	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
	Distribution Plant									
	CDMPP	$ 51,396	$ 32,621	$ 4,413	$ 5,238	$ 6,993	$ 1,196	$ 709	$ 8	$ 218
	Poles, Towers and Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	PNCP	$ 24,338,137	$ 20,697,834	$ 1,638,508	$ 246,232	$ 18,862	$ 1,730	$ 1,471,700	$ 11,144	$ 252,125
	SNCP	$ 13,229,568	$ 12,030,738	$ 190,368	$ -	$ -	$ -	$ 855,434	$ 6,478	$ 146,549
	Overhead Conductors and Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LTNCP	$ 6,915,973	$ 5,890,761	$ 466,332	$ 65,095	$ -	$ -	$ 418,857	$ 3,172	$ 71,757
	CWCS	$ 7,592,119	$ 7,076,866	$ 223,961	$ -	$ -	$ -	$ 201,278	$ 3,810	$ 86,205
	CWMC	$ 15,037,608	$ 11,132,106	$ 2,313,411	$ 1,428,484	$ 129,493	$ 34,114	$ -	$ -	$ -
	Sub-total	*$ 67,164,801*	*$ 56,860,926*	*$ 4,836,993*	*$ 1,745,050*	*$ 155,348*	*$ 37,040*	*$ 2,947,978*	*$ 24,612*	*$ 556,854*
	Accumulated Amortization									
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	$ (32,860,567)	$ (28,317,097)	$ (1,980,750)	$ (542,599)	$ (50,858)	$ (10,949)	$ (1,634,817)	$ (13,692)	$ (309,806)
	Customer Related Net Fixed Assets	$ 34,304,234	$ 28,543,828	$ 2,856,243	$ 1,202,451	$ 104,491	$ 26,092	$ 1,313,161	$ 10,920	$ 247,049
	Allocated General Plant Net Fixed Assets	$ 1,817,843	$ 1,525,025	$ 141,458	$ 56,116	$ 5,471	$ 1,217	$ 73,996	$ 616	$ 13,946
	Customer Related NFA Including General Plant	$ 36,122,077	$ 30,068,853	$ 2,997,701	$ 1,258,567	$ 109,961	$ 27,309	$ 1,387,157	$ 11,536	$ 260,994
	Misc Revenue									
	CWNB	$ (15,850)	$ (10,053)	$ (1,360)	$ (1,616)	$ (2,161)	$ (371)	$ (219)	$ (2)	$ (67)
	NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LPHA	$ (127,572)	$ (91,852)	$ (30,617)	$ (5,103)	$ -	$ -	$ -	$ -	$ -
	Sub-total	*$ (143,422)*	*$ (101,905)*	*$ (31,978)*	*$ (6,719)*	*$ (2,161)*	*$ (371)*	*$ (219)*	*$ (2)*	*$ (67)*
	Operating and Maintenance									
	1815-1855	$ 978,227	$ 858,388	$ 47,322	$ 5,848	$ 354	$ 33	$ 55,363	$ 462	$ 10,456
	1830 & 1835	$ 63,593	$ 54,947	$ 3,504	$ 495	$ 38	$ 3	$ 3,907	$ 30	$ 669
	1850	$ 126,420	$ 107,680	$ 8,524	$ 1,190	$ -	$ -	$ 7,656	$ 58	$ 1,312
	1840 & 1845	$ 91,808	$ 80,339	$ 4,149	$ 540	$ 41	$ 4	$ 5,712	$ 43	$ 979
	CWMC	$ 358,313	$ 265,253	$ 55,123	$ 34,038	$ 3,086	$ 813	$ -	$ -	$ -
	CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1830	$ 29,070	$ 25,118	$ 1,602	$ 226	$ 17	$ 2	$ 1,786	$ 14	$ 306
	1835	$ 138,795	$ 119,925	$ 7,648	$ 1,080	$ 83	$ 8	$ 8,527	$ 65	$ 1,461
	1855	$ 436,050	$ 406,457	$ 12,863	$ -	$ -	$ -	$ 11,560	$ 219	$ 4,951
	1840	$ 25,080	$ 21,947	$ 1,133	$ 148	$ 11	$ 1	$ 1,561	$ 12	$ 267
	1845	$ 59,280	$ 51,875	$ 2,679	$ 349	$ 27	$ 2	$ 3,688	$ 28	$ 632
	1860	$ 56,075	$ 41,511	$ 8,627	$ 5,327	$ 483	$ 127	$ -	$ -	$ -
	Sub-total	*$ 2,362,709*	*$ 2,033,438*	*$ 153,174*	*$ 49,241*	*$ 4,140*	*$ 993*	*$ 99,762*	*$ 930*	*$ 21,033*
	Billing and Collection									
	CWNB	$ 2,240,256	$ 1,660,858	$ 262,958	$ 276,618	$ 21,190	$ 4,165	$ 56	$ 179	$ 14,232
	CWMR	$ 294,040	$ 198,417	$ 15,708	$ 52,593	$ 20,727	$ 6,595	$ -	$ -	$ -
	BDHA	$ 150,000	$ 113,437	$ 15,747	$ 20,815	$ -	$ -	$ -	$ -	$ -
	Sub-total	*$ 2,684,296*	*$ 1,972,713*	*$ 294,413*	*$ 350,027*	*$ 41,917*	*$ 10,760*	*$ 56*	*$ 179*	*$ 14,232*
	Sub Total Operating, Maintenance and Biling	*$ 5,047,005*	*$ 4,006,151*	*$ 447,587*	*$ 399,267*	*$ 46,057*	*$ 11,753*	*$ 99,817*	*$ 1,109*	*$ 35,265*
	Amortization Expense - Customer Related	$ 1,857,323	$ 1,520,418	$ 169,335	$ 80,946	$ 11,469	$ 2,530	$ 60,479	$ 513	$ 11,633
	Amortization Expense - General Plant assigned to Meters	$ 14,857	$ 12,464	$ 1,156	$ 459	$ 45	$ 10	$ 605	$ 5	$ 114
	Admin and General	$ 3,417,755	$ 2,711,745	$ 303,156	$ 270,955	$ 31,396	$ 8,070	$ 67,848	$ 752	$ 23,833
	Allocated PILs	$ 22,975	$ 19,117	$ 1,913	$ 805	$ 70	$ 17	$ 879	$ 7	$ 165
	Allocated Debt Return	$ 1,332,918	$ 1,109,093	$ 110,982	$ 46,722	$ 4,060	$ 1,014	$ 51,024	$ 424	$ 9,599
	Allocated Equity Return	$ 1,657,001	$ 1,378,755	$ 137,965	$ 58,082	$ 5,047	$ 1,260	$ 63,430	$ 527	$ 11,933
	PLCC Adjustment for Line Transformer	$ 197,137	$ 167,909	$ 13,291	$ 1,856	$ -	$ -	$ 11,946	$ 90	$ 2,045
	PLCC Adjustment for Primary Costs	$ 239,075	$ 203,085	$ 16,275	$ 2,478	$ 190	$ 17	$ 14,446	$ 109	$ 2,474
	PLCC Adjustment for Secondary Costs	$ 873,019	$ 723,016	$ 54,356	$ -	$ -	$ -	$ 70,552	$ 466	$ 24,629
	Total	**$ 11,897,181**	**$ 9,561,827**	**$ 1,056,194**	**$ 846,184**	**$ 95,793**	**$ 24,266**	**$ 246,920**	**$ 2,669**	**$ 63,327**

ATTACHMENT 3

REVENUE REQUIREMENT WORK FORM

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

Choose Your Utility:

Guelph Hydro Electric Systems Inc.
Haldimand County Hydro Inc.
Halton Hills Hydro Inc.

File Number: EB-2011-0123

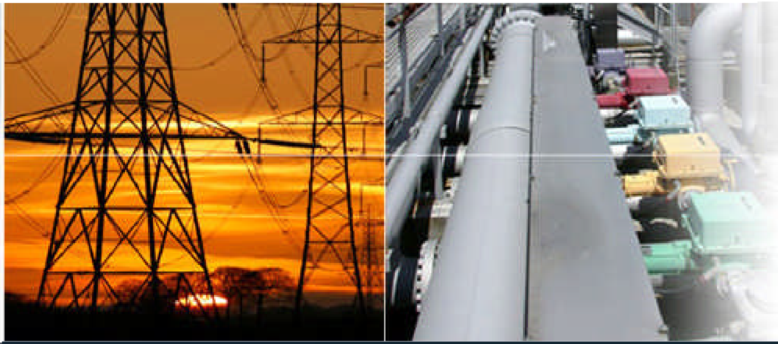
Rate Year: 2012

Click here to print the entire workbook

Application Contact Information

Name:	Cristina Birceanu
Title:	Manager of Regulatory Affairs
Phone Number:	519-837-4735
Email Address:	cbirceanu@guelphhydro.com

Copyright



Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

Guelph Hydro Electric Systems Inc.

Table of Contents

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***

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

Guelph Hydro Electric Systems Inc.

Data Input [1]

		Initial Application		Adjustments	Settlement Agreement	(6)	Adjustments	Per Board Decision
1	**Rate Base**							
	Gross Fixed Assets (average)	$178,018,480		($373,670)	$ 177,644,810			$177,644,810
	Accumulated Depreciation (average)	($63,313,009)	(5)	$689,182	($62,623,827)			($62,623,827)
	Allowance for Working Capital:							
	Controllable Expenses	$15,611,241		($1,285,241)	$ 14,326,000			$14,326,000
	Cost of Power	$143,312,358		$10,212,247	$ 153,524,605			$153,524,605
	Working Capital Rate (%)	15.00%			15.00%			15.00%
2	**Utility Income**							
	Operating Revenues:							
	Distribution Revenue at Current Rates	$24,708,000		$55,956	$24,763,956			
	Distribution Revenue at Proposed Rates	$30,652,117		($4,268,146)	$26,383,971			
	Other Revenue:							
	Specific Service Charges	$416,655		$156,011	$572,666			
	Late Payment Charges	$127,572		$0	$127,572			
	Other Distribution Revenue	$390,358		$0	$390,358			
	Other Income and Deductions	$1,116,404		$0	$1,116,404			
	Total Revenue Offsets	$2,050,989	(7)	$156,011	$2,207,000			
	Operating Expenses:							
	OM+A Expenses	$15,611,241		($1,285,241)	$ 14,326,000			$14,326,000
	Depreciation/Amortization	$6,831,714		($2,172,147)	$ 4,659,567			$4,659,567
	Property taxes	$ -			$ -			$0
	Other expenses	$ -			0			$0

		Initial Application		Adjustments	Settlement Agreement	(6)	Adjustments	Per Board Decision	
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($3,255,915)	(3)		($4,586,542)				
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$538,936			$66,273				
	Income taxes (grossed up)	$730,761			$73,246				
	Federal tax (%)	15.00%			5.44%				
	Provincial tax (%)	11.25%			4.08%				
	Income Tax Credits								
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%			56.0%			56.0%	
	Short-term debt Capitalization Ratio (%)	4.0%	(2)		4.0%	(2)		4.0%	(2)
	Common Equity Capitalization Ratio (%)	40.0%			40.0%			40.0%	
	Prefered Shares Capitalization Ratio (%)	0.0%			0.0%			0.0%	
		100.0%			100.0%			100.0%	
	Cost of Capital								
	Long-term debt Cost Rate (%)	5.26%			5.26%			5.26%	
	Short-term debt Cost Rate (%)	2.46%			2.08%			2.08%	
	Common Equity Cost Rate (%)	9.58%			9.42%			9.42%	
	Prefered Shares Cost Rate (%)	0.00%			0.00%			0.00%	

Notes:

General Data inputs are required on Sheets 3, 10A and 10B. 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) 4.0% unless an Applicant has proposed or been approved for another amount.

(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

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

Guelph Hydro Electric Systems Inc.
Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$178,018,480	($373,670)	$177,644,810	$ -	$177,644,810
2	Accumulated Depreciation (average)	(3)	($63,313,009)	$689,182	($62,623,827)	$ -	($62,623,827)
3	Net Fixed Assets (average)	(3)	$114,705,471	$315,512	$115,020,983	$ -	$115,020,983
4	Allowance for Working Capital	(1)	$23,838,540	$1,339,051	$25,177,591	$ -	$25,177,591
5	**Total Rate Base**		$138,544,011	$1,654,562	$140,198,573	$ -	$140,198,573

Allowance for Working Capital - Derivation

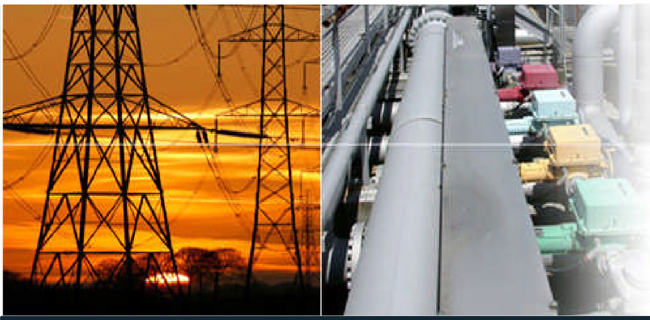
(1)

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
6	Controllable Expenses		$15,611,241	($1,285,241)	$14,326,000	$ -	$14,326,000
7	Cost of Power		$143,312,358	$10,212,247	$153,524,605	$ -	$153,524,605
8	Working Capital Base		$158,923,599	$8,927,006	$167,850,605	$ -	$167,850,605
9	Working Capital Rate %	(2)	15.00%	0.00%	15.00%	0.00%	15.00%
10	Working Capital Allowance		$23,838,540	$1,339,051	$25,177,591	$ -	$25,177,591

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study.

(3) Average of opening and closing balances for the year.



Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

Guelph Hydro Electric Systems Inc.

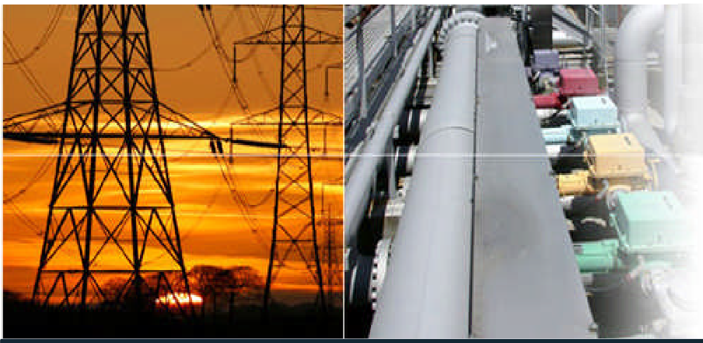
Utility Income

Line No.	Particulars	Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
	Operating Revenues:					
1	Distribution Revenue (at Proposed Rates)	$30,652,117	($4,268,146)	$26,383,971	$ -	$26,383,971
2	Other Revenue (1)	$2,050,989	$156,011	$2,207,000	$ -	$2,207,000
3	Total Operating Revenues	$32,703,106	($4,112,135)	$28,590,971	$ -	$28,590,971
	Operating Expenses:					
4	OM+A Expenses	$15,611,241	($1,285,241)	$14,326,000	$ -	$14,326,000
5	Depreciation/Amortization	$6,831,714	($2,172,147)	$4,659,567	$ -	$4,659,567
6	Property taxes	$ -	$ -	$ -	$ -	$ -
7	Capital taxes	$ -	$ -	$ -	$ -	$ -
8	Other expense	$ -	$ -	$ -	$ -	$ -
9	Subtotal (lines 4 to 8)	$22,442,955	($3,457,388)	$18,985,567	$ -	$18,985,567
10	Deemed Interest Expense	$4,220,383	$29,092	$4,249,475	$ -	$4,249,475
11	Total Expenses (lines 9 to 10)	$26,663,338	($3,428,296)	$23,235,042	$ -	$23,235,042
12	**Utility income before income taxes**	$6,039,768	($683,839)	$5,355,929	$ -	$5,355,929
13	Income taxes (grossed-up)	$730,761	($657,516)	$73,246	$ -	$73,246
14	**Utility net income**	$5,309,007	($26,323)	$5,282,683	$ -	$5,282,683

Notes

Other Revenues / Revenue Offsets

Notes	Particulars	Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
(1)	Specific Service Charges	$416,655	$156,011	$572,666		$572,666
	Late Payment Charges	$127,572	$ -	$127,572		$127,572
	Other Distribution Revenue	$390,358	$ -	$390,358		$390,358
	Other Income and Deductions	$1,116,404	$ -	$1,116,404		$1,116,404
	Total Revenue Offsets	$2,050,989	$156,011	$2,207,000	$ -	$2,207,000



Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

Guelph Hydro Electric Systems Inc.

Taxes/PILs

Line No.	Particulars	Application	Settlement Agreement	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$5,309,007	$5,282,682	$5,282,682
2	Adjustments required to arrive at taxable utility income	($3,255,915)	($4,586,542)	($3,255,915)
3	Taxable income	$2,053,091	$696,140	$2,026,767
	Calculation of Utility income Taxes			
4	Income taxes	$538,936	$66,273	$66,273
6	Total taxes	$538,936	$66,273	$66,273
7	Gross-up of Income Taxes	$191,825	$6,973	$6,973
8	Grossed-up Income Taxes	$730,761	$73,246	$73,246
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$730,761	$73,246	$73,246
10	Other tax Credits	$ -	$ -	$ -
	Tax Rates			
11	Federal tax (%)	15.00%	5.44%	5.44%
12	Provincial tax (%)	11.25%	4.08%	4.08%
13	Total tax rate (%)	26.25%	9.52%	9.52%

Notes

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

Guelph Hydro Electric Systems Inc.
Capitalization/Cost of Capital

Initial Application

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	56.00%	$77,584,646	5.26%	$4,084,056
2	Short-term Debt	4.00%	$5,541,760	2.46%	$136,327
3	**Total Debt**	60.00%	$83,126,407	5.08%	$4,220,383
	Equity				
4	Common Equity	40.00%	$55,417,604	9.58%	$5,309,007
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$55,417,604	9.58%	$5,309,007
7	**Total**	100.00%	$138,544,011	6.88%	$9,529,390

Settlement Agreement

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	56.00%	$78,511,201	5.26%	$4,132,830
2	Short-term Debt	4.00%	$5,607,943	2.08%	$116,645
3	**Total Debt**	60.00%	$84,119,144	5.05%	$4,249,475
	Equity				
4	Common Equity	40.00%	$56,079,429	9.42%	$5,282,682
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$56,079,429	9.42%	$5,282,682
7	**Total**	100.00%	$140,198,573	6.80%	$9,532,157

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$78,511,201	5.26%	$4,132,830
9	Short-term Debt	4.00%	$5,607,943	2.08%	$116,645
10	**Total Debt**	60.00%	$84,119,144	5.05%	$4,249,475
	Equity				
11	Common Equity	40.00%	$56,079,429	9.42%	$5,282,682
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$56,079,429	9.42%	$5,282,682
14	**Total**	100.00%	$140,198,573	6.80%	$9,532,157

Notes

(1) 4.0% unless an Applicant has proposed or been approved for another amount.

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

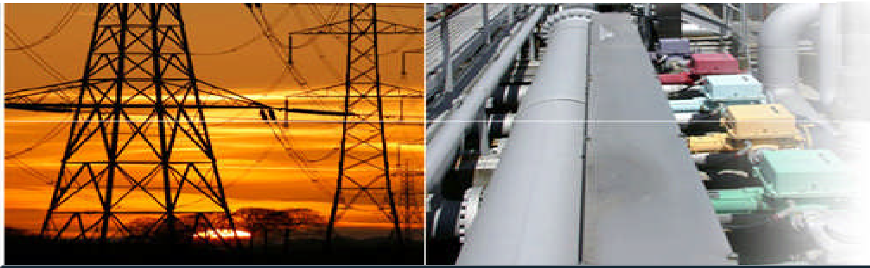
Version 2.20

Guelph Hydro Electric Systems Inc.
Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Settlement Agreement: At Current Approved Rates	Settlement Agreement: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$5,944,117		$1,620,014		$1,620,014
2	Distribution Revenue	$24,708,000	$24,708,000	$24,763,956	$24,763,957	$24,763,956	$24,763,957
3	Other Operating Revenue Offsets - net	$2,050,989	$2,050,989	$2,207,000	$2,207,000	$2,207,000	$2,207,000
4	**Total Revenue**	$26,758,989	$32,703,106	$26,970,956	$28,590,971	$26,970,956	$28,590,971
5	Operating Expenses	$22,442,955	$22,442,955	$18,985,567	$18,985,567	$18,985,567	$18,985,567
6	Deemed Interest Expense	$4,220,383	$4,220,383	$4,249,475	$4,249,475	$4,249,475	$4,249,475
	Total Cost and Expenses	$26,663,338	$26,663,338	$23,235,042	$23,235,042	$23,235,042	$23,235,042
7	**Utility Income Before Income Taxes**	$95,651	$6,039,768	$3,735,914	$5,355,929	$3,735,914	$5,355,929
8	Tax Adjustments to Accounting Income per 2009 PILs	($3,255,915)	($3,255,915)	($4,586,542)	($4,586,542)	($4,586,542)	($4,586,542)
9	**Taxable Income**	($3,160,265)	$2,783,852	($850,628)	$769,387	($850,628)	$769,387
10	Income Tax Rate	26.25%	26.25%	9.52%	9.52%	9.52%	9.52%
11	**Income Tax on Taxable Income**	($829,569)	$730,761	($80,980)	$73,246	($80,980)	$73,246
12	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
13	**Utility Net Income**	$925,220	$5,309,007	$3,816,894	$5,282,683	$3,816,894	$5,282,683

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Settlement Agreement: At Current Approved Rates	Settlement Agreement: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
14	**Utility Rate Base**	$138,544,011	$138,544,011	$140,198,573	$140,198,573	$140,198,573	$140,198,573
	Deemed Equity Portion of Rate Base	$55,417,604	$55,417,604	$56,079,429	$56,079,429	$56,079,429	$56,079,429
15	Income/(Equity Portion of Rate Base)	1.67%	9.58%	6.81%	9.42%	6.81%	9.42%
16	Target Return - Equity on Rate Base	9.58%	9.58%	9.42%	9.42%	9.42%	9.42%
17	Deficiency/Sufficiency in Return on Equity	-7.91%	0.00%	-2.61%	0.00%	-2.61%	0.00%
18	Indicated Rate of Return	3.71%	6.88%	5.75%	6.80%	5.75%	6.80%
19	Requested Rate of Return on Rate Base	6.88%	6.88%	6.80%	6.80%	6.80%	6.80%
20	Deficiency/Sufficiency in Rate of Return	-3.16%	0.00%	-1.05%	0.00%	-1.05%	0.00%
21	Target Return on Equity	$5,309,007	$5,309,007	$5,282,682	$5,282,682	$5,282,682	$5,282,682
22	Revenue Deficiency/(Sufficiency)	$4,383,786	$ -	$1,465,789	$1	$1,465,789	$1
23	**Gross Revenue Deficiency/(Sufficiency)**	$5,944,117 **(1)**		$1,620,014 **(1)**		$1,620,014 **(1)**	

Notes:
(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)



Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

Guelph Hydro Electric Systems Inc.
Revenue Requirement

Line No.	Particulars	Application	Settlement Agreement	Per Board Decision
1	OM&A Expenses	$15,611,241	$14,326,000	$14,326,000
2	Amortization/Depreciation	$6,831,714	$4,659,567	$4,659,567
3	Property Taxes	$ -	$ -	$ -
5	Income Taxes (Grossed up)	$730,761	$73,246	$73,246
6	Other Expenses	$ -	$ -	$ -
7	Return			
	Deemed Interest Expense	$4,220,383	$4,249,475	$4,249,475
	Return on Deemed Equity	$5,309,007	$5,282,682	$5,282,682
8	**Service Revenue Requirement (before Revenues)**	$32,703,106	$28,590,970	$28,590,970
9	Revenue Offsets	$2,050,989	$2,207,000	$ -
10	**Base Revenue Requirement**	$30,652,117	$26,383,970	$28,590,970
11	Distribution revenue	$30,652,117	$26,383,971	$26,383,971
12	Other revenue	$2,050,989	$2,207,000	$2,207,000
13	**Total revenue**	$32,703,106	$28,590,971	$28,590,971
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ - (1)	$1 (1)	$1 (1)

Notes

(1) Line 11 - Line 8

Consumption 800 **kWh**

			Current Board-Approved			Proposed			Impact	
		Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
1	Monthly Service Charge	monthly	$ 13.4100	1	$ 13.41	$ 14.2900	1	$ 14.29	$ 0.88	6.56%
2	Smart Meter Rate Adder	monthly	$ 1.1700	1	$ 1.17		1	$ -	-$ 1.17	-100.00%
3	Service Charge Rate Adder(s)	monthly	$ -	1	$ -	-$ 0.1165	1	-$ 0.12	-$ 0.12	
4	Service Charge Rate Rider(s)	monthly	$ -	1	$ -	-$ 0.1773	1	-$ 0.18	-$ 0.18	
5	Distribution Volumetric Rate	per kWh	$ 0.0164	800	$ 13.12	$ 0.0174	800	$ 13.92	$ 0.80	6.10%
6	Low Voltage Rate Adder	per kWh	$ 0.0001	800	$ 0.08	$ -	800	$ -	-$ 0.08	-100.00%
7	Volumetric Rate Adder(s)		$ -	800	$ -	$ -	800	$ -	$ -	
8	Volumetric Rate Rider(s)		$ -	800	$ -	$ -	800	$ -	$ -	
9	Smart Meter Disposition Rider	monthly	$ -	800	$ -	$ -	800	$ -	$ -	
10	LRAM & SSM Rate Rider	per kWh	$ -	800	$ -	$ 0.0003	800	$ 0.24	$ 0.24	
11	Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0015	800	-$ 1.20	-$ 0.0020	800	-$ 1.59	-$ 0.39	32.29%
12	Recovery of Late Payment Penalty	monthly	$ 0.2200	1	$ 0.22	$ 0.2200	1	$ 0.22	$ -	0.00%
13	Incremental Capital Module Adder	per kWh	$ 0.0008	800	$ 0.64	$ -	800	$ -	-$ 0.64	-100.00%
14	Tax Change Rate Rider	per kWh	-$ 0.0005	800	-$ 0.40	$ -	800	$ -	$ 0.40	-100.00%
15	Global Adjustment Sub-Account Di	per kWh	$ 0.0006	800	$ 0.48	-$ 0.0001	800	-$ 0.10	-$ 0.58	-120.90%
16	**Sub-Total A - Distribution**				**$ 27.52**			**$ 26.69**	**-$ 0.83**	**-3.02%**
17	RTSR - Network	per kWh	$ 0.0062	832.32	$ 5.16	$ 0.0064	816.72	$ 5.23	$ 0.07	1.29%
18	RTSR - Line and Transformation Connection	per kWh	$ 0.0052	832.32	$ 4.33	$ 0.0053	816.72	$ 4.33	$ 0.00	0.01%
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ 37.01**			**$ 36.24**	**-$ 0.76**	**-2.07%**
20	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	832.32	$ 4.33	$ 0.0052	816.72	$ 4.25	-$ 0.08	-1.87%
21	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	832.32	$ 1.08	$ 0.0013	816.72	$ 1.06	-$ 0.02	-1.87%
22	Special Purpose Charge		$ -	832.32	$ -	$ -	816.72	$ -	$ -	
23	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
24	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	0.00%
25	Energy	per kWh	$ 0.0752	832.32	$ 62.55	$ 0.0752	816.72	$ 61.38	-$ 1.17	-1.87%
26	Stranded Meter Cost Recovery Ra	monthly			$ -	$ 0.7333	1	$ 0.73	$ 0.73	
27	GEA Rate Adder (sum of Renewal	monthly			$ -	$ 0.9346	1	$ 0.93	$ 0.93	
28	**Total Bill (before Taxes)**				**$ 110.82**			**$ 110.45**	**-$ 0.37**	**-0.33%**
29	HST		13%		$ 14.41	13%		$ 14.36	-$ 0.05	-0.33%
30	**Total Bill (including Sub-total B)**				**$ 125.22**			**$ 124.81**	**-$ 0.41**	**-0.33%**
31	**Ontario Clean Energy Benefit (OCEB)**		-10%		**-$ 12.52**	-10%		**-$ 12.48**	**$ 0.04**	**-0.32%**
32	**Total Bill (including OCEB)**				**$ 112.70**			**$ 112.33**	**-$ 0.37**	**-0.33%**
33	**Loss Factor (%)**	**Note 1**	4.04%			2.09%				

Notes:
(1): Enter existing and proposed total loss factor (Secondary Metered Customer < 5,000 kW) as a percentage.

3. Smart Meter Disposition Rate Rider
4. Post Retairement Actuarial Gain (PRAG) Rate Rider
26. Stranded Meter Cost Recovery - should be considered under Sub-Total A- Distribution
27.GEA Rate Adder - should be considered under Sub-Total A - Distribution
Note: The Bill Impact does not include the 1562 PILs Disp Rate Rider because there are no more place holders for additional monthly rate riders

Consumption 2000 **kWh**

			Current Board-Approved			Proposed			Impact	
		Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
1	Monthly Service Charge	monthly	$ 12.2600	1	$ 12.26	$ 14.2900	1	$ 14.29	$ 2.03	16.56%
2	Smart Meter Rate Adder	monthly	$ 1.1700	1	$ 1.17	-$ 0.1165	1	-$ 0.12	-$ 1.29	-109.96%
3	Service Charge Rate Adder(s)	monthly	$ -	1	$ -	-$ 0.2463	1	-$ 0.25	-$ 0.25	
4	Service Charge Rate Rider(s)	monthly	$ -	1	$ -	-$ 0.4994	1	-$ 0.50	-$ 0.50	
5	Distribution Volumetric Rate	per kWh	$ 0.0156	2000	$ 31.20	$ 0.0134	2000	$ 26.80	-$ 4.40	-14.10%
6	Low Voltage Rate Adder	per kWh	$ 0.0001	2000	$ 0.20	$ -	2000	$ -	-$ 0.20	-100.00%
7	Volumetric Rate Adder(s)		$ -	2000	$ -	$ -	2000	$ -	$ -	
8	Volumetric Rate Rider(s)		$ -	2000	$ -	$ -	2000	$ -	$ -	
9	Smart Meter Disposition Rider		$ -	2000	$ -	$ -	2000	$ -	$ -	
10	LRAM & SSM Rider	per kWh	$ -	2000	$ -	$ 0.0001	2000	$ 0.20	$ 0.20	
11	Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0015	2000	-$ 3.00	-$ 0.0014	2000	-$ 2.74	$ 0.26	-8.81%
12	Recovery of Late Payment Penalty	monthly	$ 0.5700	1	$ 0.57	$ 0.5700	1	$ 0.57	$ -	0.00%
13	Incremental Capital Module Adder	per kWh	$ 0.0004	2000	$ 0.80	$ -	2000	$ -	-$ 0.80	-100.00%
14	Tax Change Rate Rider	per kWh	-$ 0.0003	2000	-$ 0.60	$ -	2000	$ -	$ 0.60	-100.00%
15	Global Adjustment Sub-Account D	per kWh	$ 0.0006	2000	$ 1.20	-$ 0.0001	2000	-$ 0.29	-$ 1.49	-124.00%
16	**Sub-Total A - Distribution**				**$ 43.80**			**$ 37.97**	**-$ 5.83**	**-13.30%**
17	RTSR - Network	per kWh	$ 0.0057	2080.8	$ 11.86	$ 0.0059	2041.8	$ 12.05	$ 0.19	1.57%
18	RTSR - Line and Transformation Connection	per kWh	$ 0.0046	2080.8	$ 9.57	$ 0.0047	2041.8	$ 9.60	$ 0.02	0.26%
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ 65.23**			**$ 59.62**	**-$ 5.61**	**-8.61%**
20	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2080.8	$ 10.82	$ 0.0052	2041.8	$ 10.62	-$ 0.20	-1.87%
21	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2080.8	$ 2.71	$ 0.0013	2041.8	$ 2.65	-$ 0.05	-1.87%
22	Special Purpose Charge		$ -	2080.8	$ -	$ -	2041.8	$ -	$ -	
23	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
24	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	0.00%
25	Energy	per kWh	$ 0.0752	2080.8	$ 156.37	$ 0.0752	2041.8	$ 153.44	-$ 2.93	-1.87%
26	Stranded Meter Cost Recovery Ra	monthly			$ -	$ 0.7333	1	$ 0.73	$ 0.73	
27	GEA Rate Adder				$ -	$ 1.9107	1	$ 1.91	$ 1.91	
28	**Total Bill (before Taxes)**				**$ 249.38**			**$ 243.22**	**-$ 6.16**	**-2.47%**
29	HST		13%		$ 32.42	13%		$ 31.62	-$ 0.80	-2.47%
30	**Total Bill (including Sub-total B)**				**$ 281.80**			**$ 274.84**	**-$ 6.96**	**-2.47%**
31	**Ontario Clean Energy Benefit (OCEB)**		-10%		**-$ 28.18**	-10%		**-$ 27.48**	**$ 0.70**	**-2.48%**
32	**Total Bill (including OCEB)**				**$ 253.62**			**$ 247.36**	**-$ 6.26**	**-2.47%**
33	**Loss Factor**	(1)	4.04%			2.09%				

Notes:
(1): See Note (1) from Sheet 10A. Bill Impacts - Residential

3. Smart Meter Disposition Rate Rider
4. Post Retairement Actuarial Gain (PRAG) Rate Rider
26. Stranded Meter Cost Recovery - should be considered under Sub-Total A- Distribution
27.GEA Rate Adder - should be considered under Sub-Total A - Distribution
Note: The Bill Impact does not include the 1562 PILs Disp Rate Rider because there are no more place holders for additional monthly rate riders