Niagara
On-The-Lake
HYDRO

March 22, 2014

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Toronto ON M4P 1E4

Via Courier and RESS

Niagara-on-the-Lake Hydro Inc. 2014 COS Rate Application
OEB Case EB-2013-0155

Dear Ms. Walli

Niagara-on-the-Lake Hydro Inc. is pleased to submit the enclosed Settlement Agreement pursuant to the Settlement Conference held on February 19 and 20, 2014, in accordance with Procedural Order No. 3.

The Parties (NOTL Hydro and the Intervenors: VECC and Energy Probe) achieved a settlement in all matters except for one:

- Eligibility of NOTL Hydro's Smart Grid Project for recording in the Green Energy/Smart Grid variance accounts

The Parties request a written hearing on the unsettled matter, for which NOTL Hydro's written submission is Appendix 1 of this Settlement Agreement. The Parties agree that the Intervenors will submit their written response within 7 calendar days of this letter.

Yours truly

Mike Galloway, President
Encl.

Cc
David Macintosh and Randy Aiken for Energy Probe
Michael Janigan, Mark Garner, Bill Harper and Donna Brady for VECC
Stephen Vetsis for OEB staff
Paul Vlahos, Facilitator

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

AND IN THE MATTER OF an application by Niagara-on-the-Lake Hydro Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2014

NIAGARA-ON-THE-LAKE HYDRO INC.
SETTLEMENT PROPOSAL

Filed March 22, 2014

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Appendix 4 – Bill Impacts (including unsettled Group 2 Rate Riders)

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INTRODUCTION

Niagara-on-the-Lake Hydro Inc. ("NOTL Hydro") filed a complete application with the Ontario Energy Board (the "Board") on September 30, 2013 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 NOTL Hydro charges for electricity distribution, to be effective May 1, 2014. The Board issued a Notice of Application and Hearing dated October 29, 2013.

The Board issued Procedural Order No. 2 dated December 20, 2013, in which the Board established an issues list for the proceeding and set dates for the filing of interrogatories and interrogatory responses

The Board issued Procedural Order No. 3 dated February 12, 2014 making provision for a Settlement Conference on February 19 and 20, 2014.

The Settlement Conference was held on February 19 and 20, 2014 with Mr. Paul Vlahos as Facilitator and was subject to the rules relating to confidentiality and privilege contained in the Board's "Settlement Conference Guidelines".

NOTL Hydro and the following intervenors (the "intervenors " and collectively including NOTL Hydro, the "parties") participated in the settlement conference and are parties to this Settlement Proposal:

- Energy Probe ("EP");

and

- Vulnerable Energy Consumers Coalition ("VECC").

Ontario Energy Board staff also participated in the settlement conference but are not a party to this Settlement Proposal.

This document is called a "Settlement Proposal" because it is a proposal by the

Parties to the Board to settle the issues in this proceeding. It is termed a proposal as between the Parties and the Board. However, as between the Parties, and subject only to the Board's approval of this Settlement Proposal, this document is intended to be a legal agreement, creating mutual obligations, and binding and enforceable in accordance with its terms. As set forth later in this Preamble, this agreement is subject to a condition subsequent, that if it is not accepted by the Board in its entirety, then unless amended by the parties it is null and void and of no further effect. In entering into this agreement, the Parties understand and agree that, pursuant to the Act, the Board has exclusive jurisdiction with respect to the interpretation or enforcement of the terms hereof.

These settlement proceedings are subject to the rules relating to confidentiality and privilege contained in 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 Proposal.

This Settlement Proposal provides a brief description of each of the settled and partially settled issues, together with references to the evidence filed to-date. The parties agree that references to the "evidence" in this Settlement Proposal shall, unless the context otherwise requires, includes (a) all interrogatory responses filed by NOTL Hydro in the within proceeding including responses to certain clarification questions from intervenors b) additional information included by the parties in this Settlement Proposal, and c) the Appendices to this document . The supporting parties for each settled or partially settled issue agree that the evidence filed to-date in respect of that settled or partially settled issue, as supplemented in some instances by additional information recorded in this Settlement Proposal, is sufficient in the context of the overall settlement to support the proposed settlement or partial settlement, and the sum of the evidence in this proceeding provides an appropriate evidentiary record to support acceptance by the Board of this Settlement Proposal.

There are Appendices to this Settlement Proposal which provide further support for the proposed settlement. The Appendices include all information and calculations that would be included in a draft rate order, including a proposed Tariff of Rates and Charges for the test year. The parties acknowledge that the Appendices were prepared by NOTL Hydro, that they constitute evidence in respect of the Application, and that the intervenors are relying on their accuracy in entering into this Settlement Proposal. .

The Board has ordered that any Settlement Proposal arising from the Settlement Conference shall be filed with the Board on or before March 6, 2014. On March 4, 2014, NOTL Hydro advised the Board that the target date for submission was revised to March 13, 2014 and the Board accepted the target date by letter dated March 6, 2014. On March 13, 2014, NOTL hydro advised the Board that the Settlement Proposal had not yet been finalized and would be submitted as soon as possible. In addition to outlining the terms of any settlement, the Board ordered that the Settlement Proposal should contain a list of any unsettled issues, indicating with reasons whether the parties believe those issues should be dealt with by way of oral or written hearing. NOTL Hydro, VECC and Energy Probe (“the Parties”) submit that these requirements have been met in this Settlement .

The Board has also indicated that Parties should be mindful that any settlement proposal must be supported with sufficient rationale for the settlement of every issue for which settlement is reached. Parties should indicate how the elements of the settlement proposal are consistent with the Board’s *Renewed Regulatory*

Framework for Electricity Distributors: A Performance- Based Approach issued on October 18, 2012 (the "RRFE Report") other Board policy, and prior Board decisions. The Parties submit that these requirements have been met in this Settlement Proposal.

Positions of the Parties

Outlined below are the final positions of the Parties following the Settlement Conference. For ease of reference, this Settlement Proposal follows the format of the final approved issues list for the Application attached to Procedural Order No. 2. The following table describes how the issues have been characterized for the purposes of this Settlement Proposal and provides a summary of the status of the issues at the outcome of the settlement conference:

Complete Settlement: An issue for which complete settlement was reached by all parties. If this Settlement Proposal is accepted by the Board, the parties will not adduce any evidence or argument during the hearing in respect of these issues.	#s of issues settled: 1, 2, 3, 4. 5. 6. 7, 8, 9.1 (other than related to Account 1535) and 9.2
No Settlement: An issue for which no settlement was reached. The Parties agree that NOTL Hydro and the Intervenors will each make a written submission on this matter requesting a Board Decision through a written hearing.	# of issue not settled: 9.1 related to Account 1535

According to the Board's *Settlement Conference Guidelines* (p. 3), the parties must consider whether a Settlement Proposal should include an appropriate adjustment mechanism for any settled issue that may be affected by external factors. NOTL Hydro and the other parties consider that no settled issue requires a specific adjustment mechanism.

The parties have settled the issues as a package and none of the parts of this Settlement Proposal is severable. If the Board does not accept this Settlement Proposal, in its entirety, then there is no settlement.

Unless stated otherwise, the settlement of any particular issue in this proceeding and the positions of the parties in this settlement proposal are without prejudice to the rights of parties to raise the same issue and/or to take any position thereon in any other proceeding, whether or not NOTL Hydro is a party to such proceeding.

Details on Unsettled Matter

As indicated above, there is one unsettled matter in this proceeding which the Parties request be resolved by a written hearing. This matter is under Issue 9.1 and only affects the balances in one Group 2 Deferral/Variance Account, namely Account 1535 – Smart Grid OM&A Deferral Account.

The Parties do not agree on whether the smart grid project was eligible for recording in the Green Energy/Smart Grid variance accounts, and consequently whether the amount that was recorded in Account 1535 is eligible for recovery. NOTL Hydro has included their written submission in Appendix 1 of this Settlement Proposal. The Intervenors have agreed to file their written reply submissions within 7 days of filing of this Settlement Proposal should the Board approve the issue to be heard by means of a written hearing.

SUMMARY

This Settlement Proposal is being filed pursuant to the Board's renewed regulatory framework. In reaching settlement, the parties have been guided by the Filing Requirements for 2014, the approved issues list, and the RRFE Report.

The parties recognize the Application is among the first to be filed under the renewed regulatory framework. The parties further recognize that this is a transition year. The parties request that the Board take this fact into consideration when reviewing this Settlement Proposal.

In the context of a comprehensive performance-based approach to regulation that is based on the achievement of outcomes that ensure that Ontario's electricity system provides value for money for customers, this Settlement Proposal should achieve the following outcomes subject to any language modifying the same in the Settlement Proposal :

- **Customer Focus:**
  - This Settlement Proposal reflects NOTL Hydro's customer focus and efforts to address the matters raised by the Intervenors who represent certain of NOTL Hydro's customer groups.
  - This Settlement Proposal will, if accepted by the Board, confirm that in consideration of the scale of NOTL Hydro and the level of the capital expenditures planned for the test year, the customer engagement activities undertaken by the applicant are commensurate with the approvals requested in the application.
- **Operational Effectiveness:**
  - This Settlement Proposal will, if accepted by the Board, result in a reduction of $75,445 in proposed OM&A expenses in the test year. OM&A is being reduced from $2,230,707 in the Application to $2,155,262 in the Settlement Proposal.
    - NOTL Hydro will continue to investigate areas that are within its control to reduce or curtail costs and better utilize existing resources.
    - NOTL Hydro commits to producing evidence of sustainable savings arising from its operational effectiveness initiatives for its next cost of service rate application.
  - This Settlement Proposal will, if accepted by the Board, result in a reduction in working capital allowance to 11% which reflects the overall resolution of those issues in the Settlement Proposal together with some efficiencies arising from monthly billing.

  - This Settlement Proposal will, if accepted by the Board, result in savings of avoided hearing costs.

- **Public Policy Responsiveness:**

  - This Settlement Proposal will, if accepted by the Board, enable NOTL Hydro to continue to meet all obligations mandated by government relevant to the Application, including in respect of renewable energy, smart meters and any other obligations that are mandated as a condition of NOTL Hydro's distribution licence.

- **Financial Performance:**

  - This Settlement Proposal should, if accepted by the Board, produce rates in the test year that will allow NOTL Hydro to meet its obligations to its customers while maintaining its financial viability.

The Total Bill Impacts resulting from the Settlement Proposal, including the DVA rate riders which are unsettled at present as discussed under Issue 9.1 are summarized below and are found in detail in *Appendix 4 – Bill Impacts (Including unsettled Group 2 Rate Riders)*:

Rate Class	**Bill**	**Per cent Increase (Decrease)**	**$ Increase (Decrease)**
Residential	Total bill on TOU (including OCEB)	(2.84%)	($3.57)
GS<50 kW	Total bill on TOU (including OCEB)	(7.69%)	($23.92)
GS>50 kW	Total Bill	(9.22%)	($755.93)
Streetlights	Total Bill	28.57%	$4.21
Unmetered Scattered Load	Total bill on TOU (including OCEB)	(24.11%)	($40.79)

Based on the foregoing, and the evidence and rationale provided below, the parties agree that this Settlement Proposal is appropriate and recommend its acceptance by the Board.

ORGANIZATION OF THE PROPOSAL

For the purposes of organizing this Proposal, the Parties have used the issue list set out in Procedural Order No 2.

The Proposal also contains the following Appendices in PDF format:

- Appendix 1 - Request for Board Decision on the Eligibility of NOTL Hydro's Smart Grid Project for recording in the Green Energy/Smart Grid variance accounts
- Appendix 2 – Response to Energy Probe Clarification Questions
- Appendix 3 – Revenue Requirement Work Form
- Appendix 4 – Bill Impacts (including unsettled Group 2 Rate Riders)
- Appendix 5 – PILS Work Form
- Series of Appendices 6 – Tables referenced under Issues 7.1, 7.2, 7.3, 7.5, 7.6, 7.7 and 8.2

In addition, the following Excel files referenced in the Settlement Proposal and reflecting the settled matters are submitted via RESS:

- Load Forecast model
- Revenue Requirement Work Form
- PILs Work Form
- Cost Allocation (RUN 3)

Niagara-on-the-Lake Hydro Inc.
2014 Cost of Service Rate Application
EB-2013-0155

ISSUES

1. Foundation

1.1 Does the planning (regional, infrastructure investment, asset management etc.) undertaken by the applicant and outlined in the application support the appropriate management of the applicant's assets?

Status:	**Complete Settlement**	
Supporting Parties:	NOTL Hydro, Energy Probe, VECC	
Evidence:	Item 1	Application: Exhibit 2, Tab 3, Schedule 1 and Appendix 2A-Distribution System Plan
	Other Items related to this issue	Responses to Interrogatories: 1.1-VECC-1/2 and 1.1-Staff-1/2 and 1.1-Energy Probe-1/2

Rationale

The Parties reviewed the RRFE Report and in particular Section 3 – "Distribution Infrastructure Investment Planning".

The Parties considered the Evidence Items referenced above in light of their review of the RRFE Report, noting that 2014 is considered a transitional year by the Board in the implementation of the RRFE.

Issue 1.1 Conclusion

For the purposes of settlement of the issues in this proceeding, the parties agree that the planning undertaken by the applicant and outlined in the application, together with the outcomes of the settlement of issues 7, 8 and 9 herein, support the appropriate management of the applicant's assets for the test year.

1.2 Are the customer engagement activities undertaken by the applicant commensurate with the approvals requested in the application?

Status:	**Complete Settlement**	
Supporting Parties:	NOTL Hydro, Energy Probe, VECC	
Evidence:	Item 1	Application: Exhibit 1, Tab 2, Schedule 1 and Appendix 1B-Customer Engagement Survey
	Other Items related to this issue	Responses to Interrogatories: 1.2-VECC-3/4/5/6/7/8 and 1.2-Energy Probe-3

Rationale

The Parties reviewed the RRFE Report and in particular the underlying focus on customers and the Board's intention to establish performance outcomes that it expects Distributors to achieve in four areas including: "Customer Focus: services are provided in a manner that responds to identified customer preferences"[1].

The Parties considered the customer engagement survey done by NOTL Hydro in June and July 2013 and noted that NOTL Hydro has attempted to reflect the results in the Distribution System Plan (e.g. the proposal to invest in a customer communication system referred to as Teleworks).

Issue 1.2 Conclusion

For the purposes of settlement of the issues in this proceeding, and in consideration of the scale of NOTL Hydro and the level of the capital expenditures planned for the test year, and based on the outcomes of the resolution of issues 7, 8 and 9, herein, the parties agree that the customer engagement activities

[1] Page 57 of RRFE Report

undertaken by the applicant are commensurate with the approvals requested in the application.

2. Performance Measures

2.1 Does the applicant's performance in the areas of: (1) delivering on Board-approved plans from its most recent cost of service decision; (2) reliability performance; (3) service quality, and (4) efficiency benchmarking, support the application?

Status:	**Complete Settlement**	
Supporting Parties:	NOTL Hydro, Energy Probe, VECC	
Evidence:	Item 1	Application: (1) Exhibit 1, Tab 5, Schedule 21 and (2 and 3) Exhibit 2 Tab 3 Schedule 5 and (4) Exhibit 4 Tab 2 Schedule 2
	Item 2	Responses to Interrogatory: 2.1-Energy Probe-4
	Other Items related to this issue	Responses to Interrogatories: 2.1-VECC-9/10 and 2.1-Staff-3 and 2.1-Energy Probe-5

Rationale

The Parties reviewed the RRFE Report and in particular Section 4 – "Performance Measurement and Continuous Improvement" and the Board's intention to establish performance outcomes that it expects Distributors to achieve in four areas including: "Operational Effectiveness: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives"[2].

The Parties considered the Evidence Items referenced above in light of their review of the RRFE Report, noting that 2014 is considered a transitional year by the Board in the implementation of the RRFE.

Delivering on Board-approved plans

The Parties note that there are no Board-approved plans from NOTL Hydro's most recent cost of service decision (case EB-2008-0237 for 2009 rates). At that time,

[2] RRFE Report Page 57

the Board did not have a requirement for a Distribution System Plan. However, the Board approved a 2009 capital expenditure level of $1,877,496. As shown in the updated 5-year forecast budget Table 2.3.1 under Issue 4.1 and reproduced below, NOTL Hydro's actual capital expenditures in 2009 were close to the approved amount at approximately $1,805,000. The Parties agree that the 2009 actual expenditures were consistent with the Board approval.

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2009			2010			2011			2012			2013			2014	2015	2016	2017	2018
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access		44	--		334	--		246	--		1,850	--		134	--	100	100	100	100	100
System Renewal		1,339	--		721	--		397	--		1,745	--		913	--	970	4,030	1,030	935	1,030
System Service		15	--		23	--		19	--		96	--		136	--	95	55	55	55	55
General Plant		407	--		449	--		397	--		491	--		140	--	120	65	65	160	65
TOTAL EXPENDITURE	-	1,805	--	-	1,527	--	-	1,059	--	-	4,182	--	-	1,322	--	1,285	4,250	1,250	1,250	1,250
System O&M		$ 839	--		$ 745	--		$ 817	--		$ 949	--		$ 894	--	$ 948	$ 963	$ 979	$ 994	$ 1,010
Checksum 2-BA1		*-$ 0*			*-$ 0*			*$ 0*			*$ 0*			12 months						

NOTL Hydro's evidence in the 2009 cost of service application outlined a five-year capital forecast in which capital expenditures were approximately $1.9 million in 2009 and approximately $1.3 million per year in the 2010 to 2012 period (excluding smart meters). The 2012 actual total of approximately $4,182,000 included the impact of the approved smart meters capital variance account disposition of approximately $1,800,000. Excluding this smart meter impact, the average capital expenditure in the 2010 to 2013 period was approximately $1.6 million.

Reliability Performance

The Parties note NOTL Hydro's historical reliability performance as shown in the following Table 2.3.3 from the Evidence Item 1:

Table 2.3.3 - Service Reliability Statistics

Year	SAIDI	SAIFI	CAIDI
Including Loss of Supply			
2009	0.33	0.28	1.2
2010	0.06	0.03	1.62
2011	15.39	4.36	3.53
2012	1.54	0.95	1.63
Excluding Loss of Supply			
2009	0.21	0.13	1.58
2010	0.06	0.03	1.62
2011	15.39	4.36	3.53
2012	0.94	0.95	0.99

The higher statistics in 2011 reflect the severe wind storm that affected NOTL's service area on April 28, 2011.

Service Quality

The Parties note NOTL Hydro's service quality performance as shown in the following Table 2.3.5 from the Evidence Item 1:

Table 2.3.5 - Reported Service Quality Indicators (SQIs)

Indicator	OEB Minimum Standard	2009	2010	2011	2012
Connection of new services - Low Voltage	90% within 5 days	100%	100%	100%	100%
Connection of new services - High Voltage	90% within 10 days	100%	100%	100%	100%
Telephone call accessibility rate	65% of calls answered within 30 seconds	89.1%	88.6%	87.7%	No data
Appointments scheduled	90% of the time	100%	100%	100%	100%
Appointments met	90% of the time	100%	100%	100%	100%
Written responses to inquiries	80% within 10 days	100%	100%	100%	100%
Emergency response - Urban Areas	80% within 60 minutes	100%	100%	100%	100%
Emergency response - Rural Areas	80% within 120 minutes	100%	100%	100%	100%

Efficiency Benchmarking

The Parties note NOTL Hydro's position in Group III – Stretch Factor 0.3% in the "*Appendix D: 2014 Stretch Factor Assignments"* of the *"Report of the Board - Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors - EB-2010-0379".*

Issue 2.1 Conclusions

For the purposes of settlement of the issues in this proceeding and based on the resolution of issues 7, 8 and 9 herein, the parties agree that:

(1) though there are no Board-approved plans from NOTL Hydro's most recent cost of service decision (2009) with which to compare the applicant's performance, the applicant has shown a history of investment in its infrastructure at levels similar to the five-year forecasts included in the 2009 application;

(2) the applicant's historical performance in terms of reliability supports the approvals sought in the application, as amended by this Settlement Proposal, for the 2014 test year;

(3) the applicant's historical performance in the area of service quality supports the application, as amended by this Settlement Proposal, for 2014; and

(4) the applicant's performance in the area of efficiency benchmarking supports the application, as amended by this Settlement Proposal, for 2014.

3. Customer Focus

3.1 Are the applicant's proposed capital expenditures and operating expenses appropriately reflective of customer feedback and preferences?

Status:	**Complete Settlement**	
Supporting Parties:	NOTL Hydro, Energy Probe, VECC	
Evidence:	Item 1	Application: Exhibit 1, Tab 2, Schedule 1 and Appendix 1B-Customer Engagement Survey and Exhibit 2 Tab 3 and Exhibit 4 Tab 2
	Other Items related to this issue	Responses to Interrogatories: 3.1-VECC-11 and 3.1-Energy Probe-6

Rationale

The Parties reviewed the RRFE Report and in particular the underlying focus on customers and the Board's intention to establish performance outcomes that it expects Distributors to achieve in four areas including: "Customer Focus: services are provided in a manner that responds to identified customer preferences" [3].

The Parties considered the Evidence Items referenced above in light of their review of the RRFE Report, noting that 2014 is considered a transitional year by the Board in the implementation of the RRFE.

Issue 3.1 Conclusion

For the purposes of settlement of the issues in this proceeding, and subject to the adjustments to the proposed capital expenditures and operating expenses described in respect of issue 7.1 below, the Parties agree that the applicant's proposed capital expenditures and operating expenses are appropriate in the

[3] RRFE Report Page 57

context of the transition test year of 2014. The Parties note that the amount of customer feedback received in the Survey appears to be commensurate with the level of capital expenditures being sought and the size of NOTL, and the Parties agree that the proposed expenses are reflective of customer feedback and preferences. This includes, but is not limited to, the feedback and preferences of the Intervenors that are party to this Settlement Proposal.

4. Operational Effectiveness

4.1 Does the applicant's distribution system plan appropriately support continuous improvement in productivity, the attainment of system reliability and quality objectives, and the associated level of revenue requirement requested by the applicant?

Status:	**Complete Settlement**	
Supporting Parties:	NOTL Hydro, Energy Probe, VECC	
Evidence:	Item 1	Application: Exhibit 2, Tab 3, Schedule 1 and Appendix 2A-Distribution System Plan and Exhibit 2 Tab 3 Schedule 5
	Item 2	Responses to Interrogatories: 1.1-Energy Probe-1
	Other Items related to this issue	Responses to Interrogatories: 4.1-VECC-12/13 and 4.1-Staff-4/5/6 and 4.1-Energy Probe-7

Rationale

The Parties reviewed the RRFE Report and in particular Section 3 – "Distribution Infrastructure Investment Planning" and the Board's intention to establish performance outcomes that it expects Distributors to achieve in four areas including: "Operational Effectiveness: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives"[4].

The Parties considered the Evidence Items referenced above in light of their review of the RRFE Report, noting that 2014 is considered a transitional year by the Board in the implementation of the RRFE.

[4] RRFE Report Page 57

The Parties noted the updated 5-year forecast budget Table 2.3.1 in the Evidence Item 2 as follows:

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2009			2010			2011			2012			2013			2014	2015	2016	2017	2018
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access		44	--		334	--		246	--		1,850	--		134	--	100	100	100	100	100
System Renewal		1,339	--		721	--		397	--		1,745	--		913	--	970	4,030	1,030	935	1,030
System Service		15	--		23	--		19	--		96	--		136	--	95	55	55	55	55
General Plant		407	--		449	--		397	--		491	--		140	--	120	65	65	160	65
TOTAL EXPENDITURE	-	1,805	--	-	1,527	--	-	1,059	--	-	4,182	--	-	1,322	--	1,285	4,250	1,250	1,250	1,250
System O&M		$ 839	--		$ 745	--		$ 817	--		$ 949	--		$ 894	--	$ 948	$ 963	$ 979	$ 994	$ 1,010
Checksum 2-BA1		*-$ 0*			*-$ 0*			*$ 0*			*$ 0*			12 months						

In 2014, the *System Service*[5] expenditure is to largely complete the integration commenced in 2012 of customer information, asset information, financial information and smart meter information from the various systems used by NOTL Hydro (“CIS”, “FIS”, “AMI”, “ODS”) utilizing the geographical information system (“GIS”) as a central data base. An Outage Management System is the final outcome. The Outage Management System will provide key information that will allow NOTL Hydro staff to proactively respond to outages, resulting in improved customer service. Engineering design staff will have up to date information such as transformer loading and asset age and condition thus potentially reducing the number of field visits.

The *System Renewal*[6] in 2014 is part of a long-term multi-year plan to replace the aging (1950s-1960s) legacy 4kV system in the Niagara-on-the-Lake “Old Town” with buried, more efficient 27.6kV facilities. The *System Renewal* also includes conversion from 4kV to 27.6 kV in rural areas. Conversion to 27.6 kV will continue to reduce distribution losses and outage calls to the benefit of customers.

Issue 4.1 Conclusion

[5] Evidence Item 1 - Distribution Plan, Page 37
[6] Evidence Item 1 - Distribution Plan, Pages 34 and 35

For the purposes of settlement of the issues in this proceeding, the parties agree that the applicant's distribution system plan appropriately supports the level of associated revenue requirement requested by NOTL Hydro for the test year 2014 pursuant to this Settlement Proposal. For the purposes of settlement of the issues in this proceeding, the parties accept the evidence herein and NOTL Hydro's confirmation that the distribution system plan appropriately supports continuous improvements in productivity and the attainment of system reliability and quality objectives at the new revenue requirement level set by this Settlement Proposal.

4.2 Are the applicant's proposed OM&A expenses clearly driven by appropriate objectives and do they show continuous improvement in cost performance?

Status:	**Complete Settlement**	
Supporting Parties:	NOTL Hydro, Energy Probe, VECC	
Evidence:	Item 1	Application: Exhibit 4, Tab 1 and Exhibit 4 Tab 2 Schedules 1/2
	Other Items related to this issue	Responses to Interrogatories: 4.2-VECC-14/15/16/17/18/19/20 and 4.2-Staff-7/8/9 and 42-Energy Probe-8/9/10/11/12/13/14

Rationale

The Parties reviewed the RRFE Report and in particular the Board's intention to establish performance outcomes that it expects Distributors to achieve in four areas including: "Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable"[7].

The Parties considered the Evidence Items referenced above in light of their review of the RRFE Report, noting that 2014 is considered a transitional year by the Board in the implementation of the RRFE

In the Evidence Item 3, NOTL Hydro proposed a 2014 OM&A total of $2,230,707. In the Evidence Item 4, NOTL Hydro proposed a reduction of $15,445 to a proposed 2014 OM&A total of $2,215,262. The Parties agree to a further reduction of $60,000 with a resulting 2014 OM&A total of $2,155,262, representing a total reduction of $75,445 from the original application.

When increases due to inflation and customer growth are taken into account, the proposed OM&A total of $2,155,262 indicates that decreases were achieved due to

[7] Page 57 of RRFE Report

continuous productivity improvements of 0.16% per annum from the 2009 Board approved total OM&A of $1,844,140 to the proposed 2014 total OM&A. The Table below shows the calculation that demonstrates the productivity improvement factor of 0.16%:

	2009 Board Approved	2010	2011	2012	2013	2014
Base OM&A	$ 1,844,140					
plus Inflation[1]		+1.00%	+2.30%	+1.90%	+1.60%	+1.70%
plus Customer Growth[2]		+0.68%	+1.13%	+1.92%	+1.88%	+2.44%
less Productivity Improvement		-0.16%	-0.16%	-0.16%	-0.16%	-0.16%
Calculated OM&A[3]	$ 1,844,140	$ 1,872,209	$ 1,933,774	$ 2,005,096	$ 2,072,114	$ 2,155,262
NOTL Hydro Proposed						$2,155,262
(1) 2010-2012 Actual, 2013-2014 Board Forecast						
(2) Exhibit 4, Tab 1, Schedule 2, Table 4.1.5						
(3) Base OM&A increased each year by the inflation and customer growth factors and decreased by the productivity improvement factors						

Issue 4.2 Conclusion

For the purposes of settlement of the issues in this proceeding, and subject to the adjustment to OM&A expenses described under issue 7.1 below, the parties agree that NOTL Hydro's OM&A expenses are driven by appropriate high-level objectives, such as reflected in NOTL Hydro's Mission and Values Statement[8], including:

<u>Providing the highest standard of safety, service and reliability</u>

- Consistently improve controlled reliability
- Assessing new technologies as they become available
- Deliver the service wanted/expected by our customers at the lowest possible cost
- Maintain the first quartile performance in the average bill to our customers amongst the Niagara-Erie area LDC's
- Achieve highest standard of E&USA equivalent Zero Quest

[8] Appendix 1H of Exhibit 1 of the original Application

In consideration of this as a transition year, for the purposes of settlement of the issues in this proceeding, and subject to the adjustment to OM&A expenses described under issue 7.1 below, the parties agree that the proposed OM&A expenses of $2,155,262, reflecting a reduction of $75,445 from the OM&A in the original application of $2,230,707, show a continuous improvement in cost performance for the purpose of the test year 2014.

4.3 Are the applicant's proposed operating and capital expenditures appropriately paced and prioritized to result in reasonable rate increases for customers, or is any additional rate mitigation required?

Status:	**Complete Settlement**	
Supporting Parties:	NOTL Hydro, Energy Probe, VECC	
Evidence:	Item 1	Application: Exhibit 2 Appendix 2A and Exhibit 8 Tab 1 Schedules 1/2
	Other Items related to this issue	Responses to Interrogatories: 4.3-Staff-10/11

Rationale

The Parties reviewed the RRFE Report and in particular Section 2.4 – "Rate Mitigation".

The Parties considered the Evidence Items referenced above in light of their review of the RRFE Report, noting that 2014 is considered a transitional year by the Board in the implementation of the RRFE.

Rate Mitigation

The adjustments made in this Settlement Proposal will not result in a rate increase for rate classes other than Street Lighting. As shown in Appendix 4 – Bill Impacts, the monthly service charges and distribution volumetric charges decrease from current rates by approximately 2% for residential customers, decrease by approximately 19% for GS<50 KW customers, decrease by approximately 18% for GS>50 kW customers and decrease by approximately 63% for unmetered scattered load customers. The monthly service charges and distribution volumetric charges for streetlights increase by approximately 49%. As indicated in the response to 4.3-Staff-11, NOTL Hydro's main streetlight customer (95% of NOTL's streetlight connections) has not provided any comment or objection since being advised of the increase in October 2013.

Pacing of Expenditures

The Parties noted as an example of appropriate pacing that there is a consistent level[9] of proposed expenditures in the period 2014 to 2018 as shown in the updated 5-year forecast budget Table 2.3.1 referenced under Issue 4.1 above and shown again below:

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2009			2010			2011			2012			2013			2014	2015	2016	2017	2018
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access		44	--		334	--		246	--		1,850	--		134	--	100	100	100	100	100
System Renewal		1,339	--		721	--		397	--		1,745	--		913	--	970	4,030	1,030	935	1,030
System Service		15	--		23	--		19	--		96	--		136	--	95	55	55	55	55
General Plant		407	--		449	--		397	--		491	--		140	--	120	65	65	160	65
TOTAL EXPENDITURE	-	1,805	--	-	1,527	--	-	1,059	--	-	4,182	--	-	1,322	--	1,285	4,250	1,250	1,250	1,250
System O&M		$ 839	--		$ 745	--		$ 817	--		$ 949	--		$ 894	--	$ 948	$ 963	$ 979	$ 994	$ 1,010
Checksum 2-BA1		*-$ 0*			*-$ 0*			*$ 0*			*$ 0*			12 months						

Issue 4.3 Conclusion

In accordance with the resolution of issues 7, 8 and 9 herein, the Parties agree that no additional rate mitigation is required for any of the rate classes. For the purposes of settlement of the issues in this proceeding, the parties agree that NOTL Hydro's proposed operating and capital expenditures, as adjusted under issue 7.1 of this Settlement Proposal, can be appropriately paced and prioritized by NOTL Hydro and will result in just and reasonable rates for customers in the test year 2014.

[9] Other than the proposed replacement and upsizing of a unit of one of NOTL Hydro's transformer stations in 2015, forecast to cost $3,000,000, as stated in NOTL Hydro's Distribution System Plan

5. Public Policy Responsiveness

5.1 Do the applicant's proposals meet the obligations mandated by government in areas such as renewable energy and smart meters and any other government mandated obligations?

Status:	Complete Settlement	
Supporting Parties:	NOTL Hydro, Energy Probe, VECC	
Evidence:	Item 1	Application: Exhibit 1 Tab 5 Schedule 15 and Exhibit 1 Tab 1 Schedule 2 and Exhibit 2 Appendix 2A and Exhibit 9 Tab 2 Schedule 1 and Exhibit 9 Tab 3 Schedule 3
	Other Items related to this issue	Responses to Interrogatories: 5.1-VECC-21 and 5.1-Staff-12/13/14/15/16/17 and 5.1-Energy Probe-15

Rationale

The Parties reviewed the RRFE Report and in particular the Board's intention to establish performance outcomes that it expects Distributors to achieve in four areas including: "Public Policy Responsiveness: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board"[10].

The Parties considered the Evidence Items referenced above in light of their review of the RRFE Report, noting that 2014 is considered a transitional year by the Board in the implementation of the RRFE.

Issue 5.1 Conclusion

For the purposes of settlement of the issues in this proceeding, the parties accept the evidence, the resolution of issues 7, 8 and 9 herein, and NOTL Hydro's confirmation that it will continue to meet all obligations mandated by government

[10] RRFE Report Page 57

relevant to this application, including in respect of renewable energy, smart meters and any other obligations that are mandated as a condition of NOTL Hydro's distribution licence in the test year 2014.

6. Financial Performance

6.1 Do the applicant's proposed rates allow it to meet its obligations to its customers while maintaining its financial viability?

Status:	**Complete Settlement**	
Supporting Parties:	NOTL Hydro, Energy Probe, VECC	
Evidence:	Item 1	Application: Exhibit 8
	Other Items related to this issue	There were no Interrogatories on this issue

Rationale

The Parties reviewed the RRFE Report and in particular the Board's intention to establish performance outcomes that it expects Distributors to achieve in four areas including: "Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable"[11].

The Parties considered the Evidence Items referenced above in light of their review of the RRFE Report, noting that 2014 is considered a transitional year by the Board in the implementation of the RRFE.

Issue 6.1 Conclusion

For the purposes of settlement of the issues in this proceeding, and subject to the adjustments noted in this Settlement Proposal for issues 7, 8 and 9, the parties agree that NOTL Hydro's proposed rates in the test year allow it to meet its obligations to its customers while maintaining its financial viability.

[11] Page 57 of RRFE Report

6.2 Has the applicant adequately demonstrated that the savings resulting from its operational effectiveness initiatives are sustainable?

Status:	**Complete Settlement**	
Supporting Parties:	NOTL Hydro, Energy Probe, VECC	
Evidence:	Item 1	Application: Exhibits 1, 2 and 4
	Item 2	Responses to Interrogatory: 6.2-Energy Probe 16.

Rationale

The Parties reviewed the RRFE Report and in particular the Board's intention to establish performance outcomes that it expects Distributors to achieve in four areas including: "Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable"[12].

The Parties considered the Evidence Items referenced above in light of their review of the RRFE Report, noting that 2014 is considered a transitional year by the Board in the implementation of the RRFE.

Issue 6.2 Conclusion

In light of the fact that this is a transition year, and as a result quantitative evidence of past operational effectiveness initiatives is not readily available, the parties agree that the applicant has adequately demonstrated that it is pursuing operational effectiveness initiatives as cited in the Evidence Item 2 (e.g. membership in the Utility Collaborative Services group of distributors, replacement of the remaining legacy 4kV system with a more efficient 27.6 kV system, reduction in line losses, implementation of an Outage Management System, File Nexus and Teleworks and the intent to add no additional staff in the current rate period). NOTL Hydro commits to producing evidence of sustainable savings arising from its operational effectiveness initiatives for its next cost of service rate application.

[12] Page 57 of RRFE Report

7. Revenue Requirement

7.1 Is the proposed Test year rate base including the working capital allowance reasonable?

Status:	**Complete Settlement**	
Supporting Parties:	NOTL Hydro, Energy Probe, VECC	
Evidence:	Item 1	Application: Exhibit 2, Tab 4, Schedule 1
	Item 2	Response to Interrogatory: 4.2-Staff-9
	Item 3	Application: Exhibit 4, Tab 2, Schedule 1
	Item 4	Response to Interrogatory: 4.2-VECC-15
	Item 5	Response to Interrogatory: 7.1-Energy Probe-19
	Item 6	Response to Interrogatory: 7.2-Energy Probe-26
	Item 7	Response to Interrogatory: 7.1-Energy Probe-24
	Item 8	Response to Interrogatory: 4.2-VECC-38
	Item 9	Application: Exhibit 3 Tab 2 Schedule 1 Table 3.2.18
	Other Items related to this issue	Response to Interrogatories: 7.1-Energy Probe-17/18/20/21/22/23/25

Fixed Assets

In response to a Clarification Question 1[13] from Energy Probe regarding the Evidence Item 5, the fixed assets ending balances for 2013 and 2014 were updated to $21,927,693 and $22,177,062, respectively.

Working Capital Allowance ("WCA") Rate

In the application, NOTL Hydro had incorporated the default value of 13% for the Working Capital Allowance rate.

This Settlement Proposal results in a reduction in working capital allowance to

[13] The clarification questions and responses are provided in Appendix 2.

11%, which reflects a complete settlement of all of the issues in this proceeding. NOTL is on monthly billing, and in the absence of a lead/lag study the Parties agree that this is a reasonable approach in light of the settlement of all of the other issues in this proceeding and the presence of monthly billing arrangements.

- ***OM&A for purposes of calculating WCA***
  As indicated under Issue 4.3, the agreed 2014 OM&A total is $2,155,262.

  The Parties agree that allocated depreciation, not being a cash expense, should be excluded from this OM&A amount for purposes of the WCA calculation. In response to Clarification Question 1[14] from Energy Probe regarding the Evidence Item 5, the updated 2014 fully allocated depreciation was identified as transportation $93,228 and stores equipment $1,293 for a total of $94,521[15]. In the Evidence Item 6, it is stated that 40% of fully +allocated depreciation is in support of operating jobs. Thus, the Parties agree that 40% of $94,521 is allocated to OM&A. Thus, the Parties agree that the OM&A for purposes of WCA calculation is $2,155,262 less $37,808, i.e. $2,117,454.

- ***Taxes other than income taxes***
  The Parties agree that the amount of Taxes other than Income Taxes is $28,596 as shown in Table 2.4.1 in the Evidence Item 1.

- ***Power Supply Expenses***
  The Parties noted the updated cost of power calculations provided in the Evidence Item 7 to reflect the OEB's RPP Report dated October 17, 2013 and the revised RTSR rates per the Evidence Item 8. Under Issue 8.1, the Parties agree that the numbers of 2013 and 2014 customers/connections in

[14] The clarification questions and responses are provided in Appendix 2.
[15] See Attachment 1 of the Clarification Response.

the Evidence Item 1 should each be adjusted. As a result of these customer adjustments, the portions of the total 2014 purchased power forecast[16] of 187,976,750 kWh in each rate class change from the Evidence Item 9 to the adjusted Table 3.2.18 provided under Issue 8.1. The 2014 power supply expenses calculation was updated to reflect these changes. The Parties agree to the adjusted 2014 power supply expenses calculation of $19,959,228, shown in detail in Appendix 6 -7.1

On the basis of the agreed amounts for each line item in the calculation of WCA as shown in the Table below, the Parties agree to the following WCA of $2,431,581:

WORKING CAPITAL ALLOWANCE FOR 2014		
OM&A		2,155,262
Less: Allocated Depreciation		(37,808)
OM&A adjusted for WCA calculation		2,117,454
Taxes Other than Income Taxes		28,596
Total Eligible Distribution Expenses		**2,146,050**
Power Supply Expenses		19,959,228
Total Working Capital Expenses		**22,105,278**
Working Capital Allowance @	11.00%	**2,431,581**

Rate Base

On this basis and using the agreed-upon working capital allowance identified above, the Parties agree to the 2014 rate base of $24,483,958 as follows:

RATE BASE CALCULATION FOR 2014	
Fixed Assets Opening Balance 2014	21,927,693
Fixed Assets Closing Balance 2014	22,177,062
Average Fixed Asset Balance for 2014	22,052,377
Working Capital Allowance	2,431,581
Rate Base	24,483,958

Issue 7.1 Conclusion

[16] Unchanged from the initial Application

The Parties agree that the proposed 2014 Test year rate base including the working capital allowance based on the above agreed components and calculation is reasonable. The changes to the WCA and rate base as a result of settlement are summarized in the table below:

	Original Application	**Change**	**Settlement**
WCA	$2,781,742	($350,161)	$2,431,581
Rate Base	$24,995,678	($511,720)	$24,483,958

7.2 Are the proposed levels of depreciation/amortization expense appropriately reflective of the useful lives of the assets and the Board`s accounting policies?

Status:	**Complete Settlement**	
Supporting Parties:	NOTL Hydro, Energy Probe, VECC	
Evidence:	Item 1	Application: Exhibit 4, Tab 3, Schedule 1
	Item 2	Response to Interrogatory: 7.7-VECC-27
	Item 3	Application: Exhibit 1, Tab 5, Schedule 17
	Other Items related to this issue	Response to Interrogatory: 7.2-Energy Probe-26

The Parties accept the proposed useful lives of assets as set out in the Evidence Item 2.

As set out in Evidence Item 3 and as stated under Issue 9.2, NOTL Hydro has made changes to the depreciation and capitalization policies effective January 1, 2013, pursuant to the Board’s regulatory accounting policy direction in the Board letter of July 17, 2012.

Table 4.3.1 in the Evidence Item 1 summarized the amortization expenses for 2009 to 2014 in the original application.

In Appendix 6–7.2, a Fixed Asset Continuity schedule for 2014 is provided which shows an updated 2014 amortization expense of $911,109 excluding fully allocated depreciation, which is accepted by the Parties.

The Parties agree that the proposed levels of depreciation/amortization expense reflecting the agreed-upon items are reflective of the useful lives of the assets and the Board`s accounting policies.

7.3 Are the proposed levels of taxes appropriate?

Status:	**Complete Settlement**	
Supporting Parties:	NOTL Hydro, Energy Probe, VECC	
Evidence:	Item 1	Application: Exhibit 4, Tab 4, Schedule 1
	Item 2	Response to Interrogatory: 7.1-Energy Probe-19/22
	Other Items related to this issue	Response to Interrogatory: 7.3-Energy Probe-27

Income Tax, Large Corporation Tax and Ontario Capital Taxes:

NOTL Hydro is subject to the payment of PILs under Section 93 of the Electricity Act, 1998, as amended.

Table 4.4.1 in the Evidence Item 1 provides a summary of 2009 Approved, the 2009, 2010, 2011, 2012 Actual, and the 2013 Bridge Year and 2014 Test Year income tax estimate using Federal and Provincial tax rates as of June 20, 2012 as specified by the OEB in the 2014 Test Year Income Tax PILs Work-form V2.0, Sheet "B. Tax Rates and Exemptions".

The Parties agree that the following adjusted Table 4.4.1 provides the accurate adjusted Income and Capital Tax amounts reflecting all other adjustments in the Settlement Proposal that affect taxes:

Table 4.4.1 – Summary of Income & Capital Taxes 2009 to 2014 –ADJUSTED

Description	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Bridge	2014 Test
Income Taxes Paid	$ 351,762	$ 376,432	$ 99,209	$ (88,838)	$ 462,731	$ 3,502	$ 32,470
Large Corporation Tax	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ontario Capital Tax	$ 15,428	$ 11,000	$ 5,000	$ -	$ -	$ -	$ -
Total Taxes	$ 367,191	$ 387,432	$ 104,209	$ (88,838)	$ 462,731	$ 3,502	$ 32,470

Capital Cost allowance

In the Evidence Item 2, NOTL Hydro updated fixed asset continuity schedules for 2013 and 2014 to include entries for truck disposals that had been inadvertently missed in the Evidence Item 1, to reflect actual 2013 capital expenditures and to re-allocate $30,000 from truck purchases to software upgrades in 2014.

In response to Clarification Question 5[17] from Energy Probe, NOTL Hydro noted that it had included the 2013 and 2014 computer hardware additions in CCA class 10 in the application, Evidence Item 1, whereas the class should be 50.

The Parties agree that the updated Table 4.4.3 and Table 4.4.5 provided in Appendix 6-7.3 correctly reflect the changes stated above, i.e. actual 2013 capital expenditures, truck disposal entries, re-allocation of $30,000 in 2014 capital expenditures from trucks to software upgrade and the re-allocation of computer hardware from CCA class 10 to CCA class 50 in 2013 and 2014.

Issue 7.3 Conclusion

The Parties agree that the adjusted tax calculation of $32,470 in the 2014 test year, reflective of the changes noted above, is appropriate.

An updated PILs work-form reflecting the agreed-upon changes above is provided via RESS and in Appendix 5 of this Settlement Proposal.

[17] See Appendix 2, Page 5

7.4 Is the proposed allocation of shared services and corporate costs appropriate?

Status:	**Complete Settlement**	
Supporting Parties:	NOTL Hydro, Energy Probe, VECC	
Evidence:	Item 1	Application: Exhibit 4, Tab 2, Schedule 3 (Shared Services and Corporate Cost Allocation)
	Other Items related to this issue	Application: Exhibit 1 Appendix 1C (Audited Financial Statements); Exhibit 1, Tab 5, Schedule 14 (Corporate and Utility Organizational Structure); Responses to Interrogatories: 7.4-VECC-23/24 and 7.4-Energy Probe-28

The Evidence Item 1 stated that:

"NOTL Hydro does not provide services to the parent company, Niagara-on-the-Lake Energy Inc., nor receive services from the parent company. No costs related to the Board of Directors of the parent company are allocated to NOTL Hydro.

NOTL Hydro does not receive any services or charges from its affiliate company, Energy Services Niagara Inc. ("ESNI").

No Board of Directors related costs for ESNI are included in NOTL Hydro's costs.

NOTL Hydro has a shared services agreement with ESNI, whereby the following services are, will be or have been provided to ESNI over the period 2009 to 2014:

- Water and wastewater billing services for users in the Town of Niagara-on-the-Lake;
- Maintenance of Town of Niagara-on-the-Lake street lights;
- Billing services and installation and maintenance of electric and gas water heater rental units owned by ESNI;
- Administrative support for the above services."

The Evidence Item 1 also stated that:

"NOTL Hydro had a pricing approach for services provided to ESNI that the Board found reasonable in the 2009 COS application (EB-2008-0237)."

The Parties agree that the pricing approach approved in the 2009 COS is still appropriate as a method of fully allocating to ESNI those costs that are incurred by NOTL Hydro on behalf of ESNI.

The Parties agree that the proposed allocation of shared services and the corporate costs, as set out in the Evidence Item 1, are appropriate.

7.5 Are the proposed capital structure, rate of return on equity and short and long term debt costs appropriate?

Status:	**Complete Settlement**	
Supporting Parties:	NOTL Hydro, Energy Probe, VECC	
Evidence:	Item 1	Application: Exhibit 5, Tab 1, Schedules 1/2
	Item 2	Responses to Interrogatories: 7.5-VECC-25 and 7.5-Energy Probe-30/31

In the Evidence Item 1, NOTL Hydro stated that it will be seeking a 10-year loan from a third party to meet anticipated cash requirements in 2014, and calculated the interest cost assuming the OEB deemed long-term debt rate at that time of 4.12%. In response to Clarification Question 6[18] from Energy Probe, NOTL Hydro stated that the applicable interest rate from Infrastructure Ontario for such a loan is currently 3.18%.

For the purposes of calculating the long-term debt rate, the Parties agree that the interest rate to be used in calculating the interest cost for this loan is 3.18%. The resulting weighted average cost of long-term debt, summarized in Appendix 6-7.5, is 4.96%. The Parties agree that NOTL Hydro has updated the remaining cost of capital parameters in NOTL Hydro`s cost of capital calculations in accordance with the Board`s letter of November 25, 2013.

The calculation of the resulting return on equity is summarized in table 5.1.1 below.

[18] See Appendix 2

Table 5.1.1 – Capital Structure 2014 – UPDATED

Deemed Capital Structure for 2014				
Description	**$**	**% of Rate Base**	**Rate of Return**	**Return**
Long Term Debt	13,711,016	56.00%	4.96%	680,095
Unfunded Short Term Debt	979,358	4.00%	2.11%	20,664
Total Debt	14,690,375	60.00%		700,759
Common Share Equity	9,793,583	40.00%	9.36%	916,679
Total equity	9,793,583	40.00%		916,679
Total Rate Base	24,483,958	100.00%	6.61%	**1,617,439**

The Parties agree that the proposed capital structure, rate of return on equity and short and long term debt costs, summarized in Table 5.1.1 above are appropriate.

7.6 Is the proposed forecast of other revenues including those from specific service charges appropriate?

Status:	**Complete Settlement**	
Supporting Parties:	NOTL Hydro, Energy Probe, VECC	
Evidence:	Item 1	Application: Exhibit 3, Tab 3, Schedule 2
	Item 2	Responses to Interrogatories: 7.1-VECC-22 and 7.6-VECC-26
	Item 3	Response to Interrogatory 7.6-Energy Probe-32

Agreed Adjustment - Account 4235 – Specific Service Charges

In Table 3.3.11 of the Evidence Item 1, NOTL Hydro forecasted 2014 revenue from Specific Service Charges at $58,300. In the Evidence Item 2, NOTL Hydro updated the proposed forecast to $76,330 as a result of a review of 2013 actual (unaudited) revenue. The Parties accept the updated 2014 forecast of Specific Service Charges at $76,330.

Agreed Adjustment - Account 4360 – Loss on Disposition of Property

In the Evidence Item 3, NOTL Hydro updated the 2013 forecast for Loss on Disposition of Property to the actual loss amount of ($7,942). The forecast loss for 2014 in this Evidence was ($30,000). The Parties agree that the forecast loss amount for 2014 should be updated to ($8,000), i.e. an amount similar to the 2013 actual amount.

Agreed Adjustment - Account 4086 – SSS Administration Revenue

As a result of the agreed adjustments to the original load forecasts of customer numbers under Issue 8.1, the calculated SSS Administration Revenue forecast for 2014 at $0.25 per customer per month increases from the original application by

$96[19] from $25,483 to $25,579. The Parties accept the forecast of $25,579.

Agreed as per Application with a note that NOTL Hydro bears the risk - Account 4340 – Profits and Losses from Fin. Inst. Hedges

NOTL Hydro has two demand instalment loans with CIBC, one to finance the construction of a transformer station and the other to finance the purchase of a transformer station from Hydro One. These loans are shown in Table 5.1.3 in Appendix 6-7.5. The loans are fixed rate loans by way of interest rate swaps. The fair values of these two interest rate swap agreements are based on amounts quoted by CIBC to realize favourable contracts or settle unfavourable contracts taking into account interest rates as at December 31st of each year[20]. A year-over-year increase in fair value of the interest rate swap is reported as a decrease in financial expense in NOTL Hydro's income statement, whereas a decrease in fair value is reported as an increase in financial expense.

The Parties accept NOTL Hydro's forecast in the Evidence Item 1 of $nil for this Account noting that this acceptance is on the basis that NOTL Hydro, not the ratepayer, bears the risk of an increase in fair value (i.e. profit) or decrease in fair value (i.e. loss).

Agreed as per Application – all other Accounts

The Parties agree that NOTL Hydro's forecasts for all other Accounts in the range from Account 4082 to Account 4405 are reasonable based on projections of historical actuals and the Parties accept these forecasts.

Summary - Total Other Revenues

The Parties agree that the total forecast of Other Revenues for 2014 is

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[19] Net increase from the load forecast in the original application of +43 – 13 + 2 = 32 customers x $0.25 x 12 months = $96

[20] See Note 18 of NOTL Hydro's 2012 Financial Statements in Appendix 1C of Exhibit 1 of the initial Application.

$282,877, as per the Table provided in Appendix 6-7.6. This amount reflects an increase of $40,126 from the total forecast in the original application of $242,751, as a result of the agreed adjustments and accepted forecasts referred to above.

7.7 Has the proposed revenue requirement been accurately determined from the operating, depreciation and tax (PILs) expenses and return on capital, less other revenues?

<table>
<tr><td>Status:</td><td colspan="2">Complete Settlement</td></tr>
<tr><td>Supporting Parties:</td><td colspan="2">NOTL Hydro, Energy Probe, VECC</td></tr>
<tr><td rowspan="4">Evidence:</td><td>Item 1</td><td>Application: Exhibit 6, Tab 1, Schedule 1</td></tr>
<tr><td>Item 2</td><td>Responses to Interrogatory 7.7-Energy Probe-33</td></tr>
<tr><td>Item 3</td><td>Responses to Energy Probe Clarification Questions</td></tr>
<tr><td>Other Items related to this issue</td><td>Responses to Interrogatories: 7.7-VECC-27 and and 7.7-Staff-18/19</td></tr>
</table>

Revenue Requirement

The application proposed a 2014 service revenue requirement of $4,788,116, which reflected a revenue sufficiency of $298,131 at current rates. As a result of the agreed-upon items in this Settlement Proposal, the Parties agree that the 2014 service revenue requirement is $4,744,877, which reflects a revenue sufficiency of $386,736 at current rates. Details of the agreed revenue sufficiency are provided in the Table 6.1.1 in Appendix 6-7.7.

The changes in service revenue requirement at each stage of the rates process to date are summarized below:

Procedural Stage	Service Revenue Requirement
Initial Application	$ 4,788,716
Changes	$ 60,364
Interrogatories Response	$ 4,849,080
Changes	$ (1,136)
Clarification Questions Response	$ 4,847,944
Changes	$ (103,067)
Settlement	$ 4,744,877
Initial Application	$ 4,788,116
Total Changes	$ (43,239)
Settlement	$ 4,744,877

The Table below shows the associated base revenue requirement of $4,462,000 after deducting the revenue offsets of $282,877 from the service revenue requirement, and shows the changes in the components of the revenue requirement from the original application to the Settlement Proposal:

Calculation of Base Revenue Requirement - Settlement vs Applicatioon			
Description	**Application**	**Change**	**Settlement**
OM&A Expenses	$ 2,230,707	-$ 75,445	$ 2,155,262
Property Taxes	$ 28,596	$ 0	$ 28,596
Amortization Expenses	$ 929,588	-$ 18,479	$ 911,109
Regulated Return on Capital	$ 1,567,217	$ 50,222	$ 1,617,439
PILs	$ 32,607	-$ 137	$ 32,470
Service Revenue Requirement	**$ 4,788,716**	**-$ 43,838**	**$ 4,744,877**
Less: Revenue Offsets	$ 242,751	$ 40,126	$ 282,877
Base Revenue Requirement	**$ 4,545,965**	**-$ 83,964**	**$ 4,462,000**

A revised Revenue Requirement Work form is provided in Appendix 3. An updated listing of the agreed Settlement changes and changes in the RRWF from the initial application to the Settlement Proposal is also provided in Appendix 3

The Parties agree that the proposed revenue requirement has been accurately determined from the operating, depreciation and tax (PILs) expenses and return on capital, less other revenues.

8. Load Forecast, Cost Allocation and Rate Design

8.1 Is the proposed load forecast, including billing determinants an appropriate reflection of the energy and demand requirements of the applicant?

<table>
<tr><td>Status:</td><td colspan="2">Complete Settlement</td></tr>
<tr><td>Supporting Parties:</td><td colspan="2">NOTL Hydro, Energy Probe, VECC</td></tr>
<tr><td rowspan="4">Evidence:</td><td>Item 1</td><td>Application: Exhibit 3, Tab 2, Schedule 1</td></tr>
<tr><td>Item 2</td><td>Response to Interrogatory: 8.1-VECC-30</td></tr>
<tr><td>Item 3</td><td>Application: Exhibit 2 Tab 4 Schedule 1 Table 2.4.4</td></tr>
<tr><td>Other Items related to this issue</td><td>Responses to Interrogatories: 8.1-VECC-28/29/31/32 and 8.1-Staff-20/21 and 8.1-Energy Probe-34</td></tr>
</table>

Purchased kWh Load Forecast

The Parties accept NOTL Hydro's purchased power forecast methodology as set out in the Evidence Item 1, resulting in weather normalized purchased load forecasts of 189,087,892 kWh for 2013 and 193,206,757 kWh for 2014 as shown in Table 3.2.7 of the Evidence Item 1.

Weather Normalized Billed kWh Forecast

The Parties accept NOTL Hydro's total weather normalized billed energy forecasts, before manual adjustments for The Outlet Collection at Niagara ("Outlet Mall") and 2013 and 2014 CDM programs, of 181,448,205 kWh for 2013 and 185,400,656 kWh for 2014 as stated on Page 15 of the Evidence Item 1.

Customer/Connection Forecast by Rate Class

The Parties reviewed the forecast of 2013 and 2014 customers/connections in Table 3.2.10 of the Evidence Item 1 and the actual 2013 customers/connections in the Evidence Item 2. The Parties agree that the numbers of 2013 and 2014 customers/connections in the Evidence Item 1 should each be adjusted as follows:

- Residential – increase by 43
- GS<50kW – decrease by 13
- GS>50kW – increase by 2

On this basis, the Parties agree that the adjusted customer/connection forecasts, prior to the manual customer adjustments for the Outlet Mall and FIT/RESOP generators set out in the Evidence Item 1 pages 17 and 18, are as in the following adjusted Table 3.2.10:

Table 3.2.10: Customer/Connection Forecast - ADJUSTED						
Year	Residential	GS<50	GS>50	Street Lighting	USL	Total
Forecast Number of Customers/Connections						
2013	7,008	1,241	122	2,003	22	10,396
2014	7,158	1,243	126	2,058	22	10,607

Usage per Customer

The Parties accept NOTL Hydro's forecast of annual kWh usage per customer in 2013 and 2014 as per Table 3.2.13 in the Evidence Item 1.

Non-Normalized Weather Billed kWh Forecast

Table 3.2.14 in the Evidence Item 1 sets out the Non-Normalized Weather Billed Energy Forecasts prior to the agreed adjustments in customers/connections. Based on the agreed customer/connection forecasts in Table 3.2.10 above and the agreed usage per customer, the Parties agree that the Adjusted Non-Normalized Weather Billed Energy Forecasts are as in the following adjusted Table 3.2.14:

Table 3.2.14: Non-normalized Weather Billed Energy Forecast (kWh) - ADJUSTED						
Year	Residential	GS<50	GS>50	Street Lighting	USL	Total
NON-normalized Weather Billed Energy Forecast (kWh)						
2013 (Not Normalized)	68,569,999	35,238,471	81,929,867	1,205,215	238,007	187,181,559
2014 (Not Normalized)	69,544,425	35,282,095	83,306,834	1,248,464	240,322	189,622,140

Weather Adjustment

Table 3.2.18 in the Evidence Item 1 sets out that the alignment of the non-normalized billed energy forecast with the normalized forecast in the original application.

The Parties accept that the weather sensitivity by rate class is per Table 3.2.15 in the Evidence Item 1. The Parties accept that the difference between the normalized and the non-normalized billed kWh forecasts is assigned on a pro-rata basis to each rate class based on the level of weather sensitivity. As a result of the effect of the adjustment in the customer/connection forecasts agreed to by the Parties, the agreed weather adjustments are negative (5,733,354) kWh in 2013 (i.e. 187,181,559 – 181,448,205) and negative (4,221,484) kWh in 2014 (i.e. 189,622,140 – 185,400,656)[21].

CDM and Outlet Mall

The Parties accept the original manual billed kWh adjustments for CDM and the Outlet Mall set out in the Evidence Item 1.

Normalized Billed Energy Forecast (kWh)

Based on the above agreed adjustments for weather, CDM and the Outlet Mall, the Parties agree that the alignment of the non-normalized billed energy forecast with the normalized forecast is per the following adjusted Table 3.2.18:

[21] The differences in the original application, Evidence Item 1 Table 3.2.18, were negative (4,341,397) kWh in 2013 and negative (2,846,088) kWh in 2014. The net increase in customers in the Settlement results in an increased non-normalized kWh forecast and consequently a larger negative weather sensitivity adjustment.

Table 3.2.18: Alignment of Non-normal to Weather Normal Forecast - ADJUSTED							
Year	Residential	GS<50	GS>50	Street Lighting	Sentinels	USL	Total
Non-normalized Weather Billed Energy Forecast (kWh)							
2013 Non-Normalized Bridge	68,569,999	35,238,471	81,929,867	1,205,215		238,007	187,181,559
2014 Non-Normalized Test	69,544,425	35,282,095	83,306,834	1,248,464		240,322	189,622,140
Weather Adjustment (kWh)							
2013	-2,249,642	-1,156,102	-2,327,610	0		0	-5,733,354
2014	-1,658,972	-841,649	-1,720,863	0		0	-4,221,484
Manual Adjustments - CDM (kWh)							
2013	-73,439	-514,075	-146,879	0		0	-734,393
2014	-132,043	-924,300	-264,086	0		0	-1,320,428
Manual Adjustments - Outlet Mall (kWh)							
2013	0	0	0	0		0	0
2014	0	3,744,552	151,970	0		0	3,896,522
Weather Normalized Billed Energy Forecast (kWh)							
2013 Normalized Bridge	66,246,918	33,568,294	79,455,378	1,205,215		238,007	180,713,812
2014 Normalized Test	67,753,410	37,260,698	81,473,856	1,248,464		240,322	187,976,750

LRAM Variance Account

The Parties accept the 2014 expected savings for the LRAM Variance Account as set out in Table 3.2.17 in the Evidence Item 1 and shown below:

Table 3.2.17: 2014 Expected Savings for LRAM Variance Account							
	Residential	GS<50	GS>50	Street Lighting	Sentinels	USL	Total
kWh	461,087	1,231,015	1,187,082	0		0	2,879,184
kW where applicable			1,104	0			1,104

Billed KW Load Forecast

The Parties accept the average kW/kWh ratio in Table 3.2.20 in the Evidence Item 1 as the ratio to be applied to the weather normalized billed energy forecast to provide the forecast of kW for the applicable rate classes. On this basis, the Parties agree that the forecast of kW by rate class reflecting the adjusted weather normalized billed kWh forecast is per the following adjusted Table 3.2.21:

Table 3.2.21: kW Forecast by Applicable Rate Class - ADJUSTED				
Year	GS>50	Street Lighting	Sentinels	Total
Predicted Billed kW				
2013 Normalized Bridge	196,560	3,260		199,820
2014 Normalized Test	201,178	3,377		204,554

Summary

The Parties agree that the following Table provides an accurate summary of the agreed adjustments to the load forecast data resulting from all of the above[22].

In addition, The Table below shows the cost of power by rate class resulting from the agreed forecast, with the agreed adjustments being the differences between the Evidence Item 3 and the Table under "Power Supply Expenses" under Issue 7.1.

An updated load forecast Excel model reflecting the Settlement Proposal is provided via RESS.

[22] The numbers of customers in the Summary Table are the numbers at 2014 year-end. The agreed adjustments for 2013 year-end are the same as for the 2014 year-end. Consequently the same adjustments apply to the 2014 average numbers of customers.

2014 LOAD FORECAST - SETTLEMENT SUMMARY

RATE CLASS	APPLICATION AS FILED	AGREED ADJUSTMENTS	SETTLEMENT PROPOSAL
Residential			
Customers at year-end	7,115	43	7,158
kWh	67,875,319	(121,909)	67,753,410
Cost of Power	6,944,665	$ 366,684	$ 7,311,349
General Service< 50 kW			
Customers at year-end	1,351	(13)	1,338
kWh	37,894,182	(633,484)	37,260,698
Cost of Power	3,832,723	$ 138,471	3,971,194
General Service> 50 kW			
Customers at year-end	126	2	128
kWh	80,718,464	755,392	81,473,856
kW	199,309	1,869	201,178
Cost of Power	8,211,717	$ 310,437	8,522,154
Streetlights			
Connections at year-end	2,058	0	2,058
kWh	1,248,464	(0)	1,248,464
kW	3,377	(0)	3,377
Cost of Power	125,408	$ 3,556	128,964
Unmetered Loads			
Customers at year-end	22	(0)	22
kWh	240,322	0	240,322
Cost of Power	24,199	$ 1,368	25,567
Total of Above			
Customer/Connections	10,672	32	10,704
kWh	187,976,750	0	187,976,750
kW from applicable classes	202,686	1,868	204,554
Cost of Power	$ 19,138,712	$ 820,516	$ 19,959,228

Issue 8.1 Conclusion

The Parties agree that the proposed load forecast, including billing determinants, based on the above agreements is an appropriate reflection of the energy and demand requirements of NOTL Hydro for the Test year 2014.

8.2 Is the proposed cost allocation methodology including the revenue-to-cost ratios appropriate?

<table>
<tr><td>Status:</td><td colspan="2">Complete Settlement</td></tr>
<tr><td>Supporting Parties:</td><td colspan="2">NOTL Hydro, Energy Probe, VECC</td></tr>
<tr><td rowspan="3">Evidence:</td><td>Item 1</td><td>Application: Exhibit 7, Tab 1, Schedules 1 and 2</td></tr>
<tr><td>Item 2</td><td>Response to Interrogatory: 8.2-VECC-34</td></tr>
<tr><td>Other Items related to this issue</td><td>Response to Interrogatories: 8.2-VECC-33/35 and 8.2-Staff-22/23</td></tr>
</table>

Services (account 1855)

In Table 7.1.1 of the Evidence Item 1, NOTL Hydro proposed a service weighting factor of 1.00 for the Residential class and factors of 0.00 for all the other classes. In answering a written Clarification Question 7[23] from Energy Probe regarding NOTL Hydro's response to 8.2-VECC-34 (Evidence Item 2), NOTL Hydro determined that it had incorrectly calculated the weightings for Table 7.1.1 given that NOTL Hydro does maintain services for GS<50 and USL that have an ampacity of 200 or less. The Parties agree to the corrected services weighting factors, replacing the factors in Table 7.1.1 in the application, as follows:

- Residential 1.00
- GS<50 0.76
- USL 0.37
- GS> 50 0.00
- Street Lights 0.00

The Parties agree on the updated cost allocation model (designated as RUN 3 and provided via RESS) reflecting this correction and the effect of all other relevant adjustments agreed to in this Settlement Proposal. Updated sheets I6, I8, O1 and O2 are provided In Appendix 6-8.2. With regard to sheet O1, the Parties agree that

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[23] See Appendix 2

in the calculation of working capital allowance, the allocated depreciation is excluded from the OM&A for each rate class in proportion to the total OM&A for each rate class.

Allocated Costs and Revenue to Cost Ratios

The Parties agree that the adjusted Table 7.1.8 below accurately reflects the effects of all other relevant adjustments agreed to in this Settlement Proposal.

Table 7.1.8 – Allocated Costs – ADJUSTED

Classes	**Costs Allocated from Previous Study**	**%**	**Costs Allocated in Test Year Study (Column 7A)**	%
Residential	$ 2,637,013	53.22%	$ 2,844,235	59.94%
GS < 50 kW	$ 1,277,325	25.78%	$ 869,164	18.32%
GS > 50 kW	$ 760,738	15.35%	$ 691,959	14.58%
Street Lighting	$ 250,797	5.06%	$ 333,612	7.03%
Unmetered Scattered Load (USL)	$ 29,120	0.59%	$ 5,907	0.12%
Total	$ 4,954,993	100.00%	$ 4,744,877	100.00%

The agreed revenue-to-cost ratios in Table 7.1.9 below are calculated by adjusting the allocations of revenue among rate classes in order to be within the Board's target range as set out in the March 31, 2011 *Report of the Board on Cost Allocation* released in relation to EB-2010-0219. Specifically, the revenue-to-cost ratios for the GS<50 kW, GS>50 kW and USL classes are moved down to the target range at 120%. The Residential and Streetlighting ratios are set at the same level as each other and then this level is adjusted to the balancing ratio needed to maintain revenue neutrality, i.e. 90.14%

Table 7.1.9 – Revenue-to-Cost Ratios – ADJUSTED

Rate Class	2011 Board Approved	2014 Updated Cost Allocation Study	2014 Proposed Ratios	Board Targets	
				Min to Max	
Residential	95%	85.0%	90.14%	85%	115%
GS<50 kW	96%	135.4%	120.00%	80%	120%
GS>50 kW	134%	135.5%	120.00%	80%	120%
Streetlighting	70%	58.2%	90.14%	70%	120%
Unmetered Scattered Load	100%	288.6%	120.00%	80%	120%

Issue 8.2 Conclusion

The Parties note that the proposed revenue-to-cost ratios are all within the Board target ranges and agree that the proposed cost allocation methodology including the revenue-to-cost ratios based on the above agreements is appropriate.

8.3 Is the proposed rate design including the class-specific fixed and variable splits and any applicant-specific rate classes appropriate?

Status:	**Complete Settlement**	
Supporting Parties:	NOTL Hydro, Energy Probe, VECC	
Evidence:	Item 1	Application: Exhibit 8, Tab 1, Schedule 1
	Other Items related to this issue	Responses to Interrogatories: 8.3-VECC-36 and 8.3-Staff-24 and 8.3-Energy Probe-36

DISTRIBUTION RATE DESIGN:

The Evidence Item 1 sets out the calculation of NOTL Hydro's originally proposed distribution rates by rate class for the 2014 Test Year.

NOTL Hydro has updated the total 2014 service revenue requirement to be $4,744,877 based on the effect of all relevant adjustments agreed to in this Settlement Proposal. The total adjusted revenue offsets in the amount of $282,877 reduce NOTL Hydro's total service revenue requirement to a base revenue requirement of $4,462,000 which is used to determine the agreed-upon distribution rates. The revenue requirement is summarized in Table 8.1.1under Issue 7.7:

The outstanding base revenue requirement is allocated to the various rate classes using the adjusted revenue to cost ratios outlined in Table 7.1.9 under Issue 8.2 above. The following Table 8.1.2 shows how the base revenue requirement has been allocated to the rate classes.

Table 8.1.2 Rate Class Base Revenue Requirement	
Rate Class	2014 Base Revenue Requirement
Residential	$ 2,381,452
GS<50 kW	$ 994,528
GS>50 kW	$ 800,431
Streetlighting	$ 278,919
Unmetered Scattered Load	$ 6,670
Total	$ 4,462,000

Determination of Monthly Fixed Charges:

Based on applying the existing approved monthly service charges to the forecasted number of customers for 2014 and applying the existing approved distribution volumetric charge excluding the adjustment for transformation allowance, to 2014 forecasted volumes the following Table 8.1.3 outlines NOTL Hydro's current split between fixed and variable distribution revenue.

Table 8.1.3 Current Fixed Variable Split					
Rate Class	2014 Fixed Base Revenue with 2013 Approved Rates	2014 Variable Base Revenue with 2013 Approved Rates	2014 Total Base Revenue with 2013 Approved Rates	Fixed Revenue Proportion	Variable Revenue Proportion
Residential	$ 1,556,349	$ 874,019	$ 2,430,368	64.04%	35.96%
GS<50 kW	$ 712,290	$ 514,198	$ 1,226,488	58.08%	41.92%
GS>50 kW	$ 492,268	$ 494,409	$ 986,676	49.89%	50.11%
Streetlighting	$ 121,357	$ 65,777	$ 187,134	64.85%	35.15%
Unmetered Scattered Load	$ 14,152	$ 3,917	$ 18,069	78.32%	21.68%
Total	$ 2,896,416	$ 1,952,319	$ 4,848,735	59.74%	40.26%

Consistent with the Board Decisions on 2011 cost of service rate applications for Hydro One Brampton, Kenora Hydro and Horizon Utilities, the Board's Decision on Atikokan Hydro's 2012 cost of service application, as well as the Board's recent Decision on Centre Wellington Hydro's 2013 cost of service application, the Parties agree to maintain the current fixed/variable proportions for all rate classes. The following Table 8.1.4 outlines the calculation of the proposed monthly service charge by rate class.

Table 8.1.4 Proposed Monthly Service Charge

Rate Class	2014 Total Base Revenue Requirement	Fixed Revenue Proportion	Fixed Revenue	Customers/ Connections	Proposed Monthly Service Charge
Residential	$ 2,381,452	64.04%	$ 1,525,025	7,083	$ 17.94
GS<50 kW	$ 994,528	58.08%	$ 577,578	1,291	$ 37.28
GS>50 kW	$ 800,431	49.89%	$ 399,347	125	$ 266.42
Streetlighting	$ 278,919	64.85%	$ 180,880	2,031	$ 7.42
Unmetered Scattered Load	$ 6,670	78.32%	$ 5,224	22	$ 20.05
Total	$ 4,462,000	59.74%	$ 2,688,053		

Table 8.1.5 below compares the current and proposed monthly fixed charges with the floor and ceiling as calculated in the cost allocation study:

Table 8.1.5: Monthly Service Charge Information from Cost Allocation Model

Rate Class	Current Service Charge	Proposed Service Charge	Customer Unit Cost per month - Avoided Cost	Customer Unit Cost per month - Minimum System with PLCC Adjustment
Residential	$ 18.31	$ 17.94	$ 8.31	$ 25.49
GS<50 kW	$ 45.97	$ 37.28	$ 9.42	$ 24.42
GS>50 kW	$ 328.41	$ 266.42	$ 29.02	$ 49.85
Streetlighting	$ 4.98	$ 7.42	$ 0.92	$ 13.64
Unmetered Scattered Load	$ 54.31	$ 20.05	$ 3.81	$ 16.85

Proposed Volumetric Charges:

The volumetric distribution charge is calculated by dividing the variable distribution portion of the base revenue requirement by the appropriate 2014 Test Year usage, kWh or kW, as the class charge determinant.

The following Table 8.1.6 provides the agreed-upon calculations of NOTL Hydro's volumetric distribution charges for the 2014 Test Year assuming the fixed/variable split used in designing the monthly service charge.

Table 8.1.6 Proposed Distribution Volumetric Charge

Rate Class	2014 Total Base Revenue Requirement	Fixed Revenue	Variable Revenue	Annualized kWh or kW as required	Unit of Measure	Proposed Volumetric Distribution Charge before transformer allowance
Residential	$ 2,381,452	$ 1,525,025	$ 856,427	67,753,410	kWh	$0.0126
GS<50 kW	$ 994,528	$ 577,578	$ 416,950	37,260,698	kWh	$0.0112
GS>50 kW	$ 800,431	$ 399,347	$ 401,084	201,178	kW	$1.9937
Streetlighting	$ 278,919	$ 180,880	$ 98,039	3,377	kW	$29.0338
Unmetered Scattered Load	$ 6,670	$ 5,224	$ 1,446	240,322	kWh	$0.0060
Total	$ 4,462,000	$ 2,688,053	$ 1,773,947			

Transformer Allowance

The Parties accept the proposed maintenance of the current rate of $0.56 per kW of demand per month for the 2014 test year for eligible GS>50kW customers as set out on Pages 4 and 5 of the Evidence Item 1.

However, in order to ensure NOTL Hydro collects the proposed distribution revenue assigned to the rate class, which provides a Transformer Allowance, the total amount or "cost" of the Transformer Allowance for the rate class needs to be collected in the distribution volumetric rates from all customers in the class. This will allow NOTL Hydro to collect distribution revenue from the rate class at the "gross" level, then to provide a Transformer Allowance which will reduce the gross distribution revenue to a "net" level. The net level amount will be equivalent to the proposed distribution revenue assigned to the rate class.

As a result, the amount of Transformer Allowance expected to be provided to those GS>50kW customers that own their transformers is included in the volumetric charge for the class. The proposed "net" volumetric charge of $1.9937 per kW for the GS>50kW class is increased by $0.1088 per kW to include $21,894 or the "cost" of the Transformer Allowance in the GS>50kW class volumetric charge.

This means the “gross” proposed distribution volumetric charge for this class will be $2.1025. The Parties note that this approach to the calculation of this charge is common practice, not unique to NOTL Hydro and was the approach in the original 2014 COS application and in NOTL Hydro’s Board-approved 2009 COS.

Proposed Distribution Rates:

The following Table 8.1.7 sets out the agreed-upon 2014 electricity distribution rates based on the foregoing calculations.

Table 8.1.7 Proposed Distribution Rates			
Rate Class	Proposed Monthly Service Charge	Unit of Measure	Proposed Volumetric Distribution Charge including transformer allowance adjustment
Residential	$17.94	kWh	$0.0126
GS<50 kW	$37.28	kWh	$0.0112
GS>50 kW	$266.42	kW	$2.1025
Streetlighting	$7.42	kW	$29.0338
Unmetered Scattered Load	$20.05	kWh	$0.0060
Transformer Discount		kW	-$0.56

Issue 8.3 Conclusion

The Parties agree that the proposed rate design including the class-specific fixed and variable splits based on the above agreements is appropriate. The Parties agree that NOTL Hydro has no applicant-specific rate classes.

8.4 Are the proposed Total Loss Adjustment Factors appropriate for the distributor's system and a reasonable proxy for the expected losses?

Status:	**Complete Settlement**	
Supporting Parties:	NOTL Hydro, Energy Probe, VECC	
Evidence:	Item 1	Application: Exhibit 8, Tab 1, Schedule 1
	Other Items related to this issue	Response to Interrogatory: 8.4-VECC-37

Total Loss Factor by Class

The Parties agree to the class-specific Loss Factors used by NOTL Hydro in the calculation of commodity and other non-distribution charges for the 2014 test year as set out in Table 8.1.9 in the Evidence Item 1 and shown below:

Table 8.1.9 Total Loss Factor by Class

Loss Factors	
Supply Facilities Loss Factor (5 year average)	1.0045
Distribution Loss Factor - Secondary Metered Customers < 5,000 kW	1.0333
Distribution Loss Factor - Primary Metered Customers < 5,000 kW	1.0229
Total Loss Factor - Secondary Metered Customers < 5,000 kW	1.0379
Total Loss Factor - Primary Metered Customers < 5,000 kW	1.0275

Issue 8.4 Conclusion

The Parties agree that the proposed Total Loss Adjustment Factors based on the above agreement are appropriate for the NOTL Hydro's system and a reasonable proxy for the expected losses.

8.5 Is the proposed forecast of other regulated rates and charges including the proposed Retail Transmission Service Rates appropriate?

Status:	**Complete Settlement**	
Supporting Parties:	NOTL Hydro, Energy Probe, VECC	
Evidence:	Item 1	Application: Exhibit 8, Tab 1, Schedule 1
	Item 2	Response to Interrogatory: 8.5-VECC-38
	Other Items related to this issue	Response to Interrogatory: 8.5-Staff-25

Updated Retail Transmission and Service ("RTS") Rates

NOTL Hydro proposed RTS rates in Table 8.1.7 in the Evidence Item 1 based on the UTRs approved by the Board at that time. In the Evidence Item 2, NOTL Hydro updated the proposed RTS rates for 2014 based on the 2014 UTRs approved by the Board on January 9, 2014 in case EB-2012-0031. The Parties accept the updated RTS rates in the Evidence Item 2 and as shown below:

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Residential	kWh	$ 0.0072	$ 0.0013
General Service Less Than 50 kW	kWh	$ 0.0066	$ 0.0013
General Service 50 to 4,999 kW	kW	$ 2.6853	$ 0.4602
General Service 50 to 4,999 kW – Interval Metered	kW	$ 2.9023	$ 1.1068
Unmetered Scattered Load	kWh	$ 0.0066	$ 0.0013
Street Lighting	kW	$ 2.0249	$ 0.3558

The updated RTSR Excel work form was provided via RESS on February 6, 2014 as file "NOTL_RTSR_VECC IR38_20140206".

Updated Rural or Remote Protection Plan Rate

The Evidence Item 1 Page 8 set out the Rural or Remote Protection Plan Rate of $0.0012 per kWh that was effective May 1, 2013. The Parties accept the proposed Rural or Remote Protection Plan Rate of $0.0013 per kWh as updated by the Board to be effective May 1, 2014.

Retail Service Charges; Wholesale Market Services rates; Smart Metering Charge; and Specific Service Charges

The Parties accept the proposed Retail Service Charges, Wholesale Market Service Charge, Smart Metering Charges and Specific Service Charges as set out in the Evidence Item 1, pages 7 to 9,

Issue 8.5 Conclusion

The Parties agree that the proposed forecast of other regulated rates and charges including the proposed Retail Transmission Service Rates based on the above acceptances is appropriate.

8.6 Is the proposed Tariff of Rates and Charges an accurate representation of the application, subject to the Board's findings on the application?

Status:	**Partial Settlement**	
Supporting Parties:	NOTL Hydro, Energy Probe, VECC	
Evidence:	Item 1	Application: Exhibit 8, Tab 1, Schedule 1
	Item 2	Application: Exhibit 8, Tab 3, Schedule 2
	Other Items related to this issue	There were no Interrogatories on this Issue

The Parties agree that a complete Tariff of Rates and Charges would not be included in this Settlement Proposal as there is a matter not settled as indicated below, but the Parties acknowledge that a complete Tariff will be required after the Board decision on the unsettled matter. At this time, a summary of rates and charges settled and not settled is provided below.

MATTER NOT SETTLED[24]

Rate Riders for Group 2 Accounts exc. 1568 and 1592 as affected by Proposed Disposition of Account 1535 – Smart Grid OM&A Deferral Account

Table 9.3.9 in the Evidence Item 2 is reproduced below. Because the "Group 2 Accounts exc. 1568 and 1592 " include Account 1535, the rate riders for this Group of Accounts are not settled.

[24] See "Matter Not Settled" Under Issue 9.1

Table 9.3.9: 2014 Deferral and Variance Account Rate Rider by Class

Rate Class	Group 1 Accounts	Group 2 Accounts exc. 1568 and 1592	Group 2 Accounts 1568 and 1592	Total	2012 Actual Load Data	Billing Factor	Rate
Residential	$(297,907)	$ 278,310	$(14,783)	**$ (34,380)**	66,912,797	kWh	$ (0.0005)
General Service Less Than 50 kW	$(157,192)	$ 78,571	$ 9,250	**$ (69,370)**	35,318,239	kWh	$ (0.0020)
General Service 50 to 4,999 kW	$(353,154)	$ 78,045	$ (8,578)	**$ (283,688)**	203,974	kW	$ (1.3909)
Unmetered Scattered Load	$ (981)	$ 1,003	$ (150)	**$ (128)**	219,430	kWh	$ (0.0006)
Street Lighting	$ (5,165)	$ 3,376	$ (1,800)	**$ (3,590)**	3,238	kW	$ (1.1086)
Total	**$(814,400)**	**$ 439,305**	**$(16,061)**	**$ (391,155)**			

MATTERS SETTLED

Proposed Distribution Rates

The settled distribution rates are shown in Table 8.1.7 under Issue 8.1 above.

Total Loss Factor by Class

The settled loss factors are shown in Table 8.1.9 under Issue 8.1 above.

Retail Transmission and Service (“RTS”) Rates

The settled RTS rates are shown under Issue 8.5 above.

Retail Service Charges; Wholesale Market Services rates; and Specific Service Charges

As indicated under Issue 8.5 above, the settled charges are as set out in the Evidence Item 1, Tables 8.1.8, 8.1.9 and 8.1.10 with the exception of the Rural or Remote Protection Plan Rate which is agreed to be updated to $0.0013 per kWh.

Smart Metering Charge

As indicated under Issue 8.5 above, the settled charges are as set out in the Evidence Item 1, namely a Smart Metering charge of $0.79 per month for Residential and General Service < 50 kW customers.

Rate Riders for Non-RPP Global Adjustment

The settled rate riders are as set out in the Evidence Item 2, Table 9.3.10. This Table is reproduced below.

Table 9.3.10: 2014 Non-RPP Global Adjustment Rate Rider by Class

Rate Class	RSVA - Global Adjustment	2012 Non-RPP Quantities	Billing Factor	Rate
Residential	$ (4,934)	2,326,644	kWh	$ (0.0021)
General Service Less Than 50 kW	$ (6,637)	3,129,726	kWh	$ (0.0021)
General Service 50 to 4,999 kW	$ (156,558)	189,784	kW	$ (0.8249)
Unmetered Scattered Load	$ -	-	kWh	$ -
Street Lighting	$ (2,252)	2,955	kW	$ (0.7620)
Total	**$ (170,381)**			

BILL IMPACTS

Notwithstanding that the Board decision on the unsettled matter regarding Account 1535 is not yet known, and consequently that the decision on the Rate Riders for Group 2 Accounts exc. 1568 and 1592 as set out in Table 9.3.9 above is not yet known, the Appendix 4 to this Settlement Proposal is intended to show the bill impacts including the proposed rate riders in Table 9.3.9.

Issue 8.6 Conclusion

The Parties agree that, except for the Rate Riders for Group 2 Accounts exc. 1568 and 1592 which are subject to the Board decision on the unsettled matter of Account 1535, the rates and charges set out above are an accurate representation of the agreed-upon items.

9. Accounting

9.1 Are the proposed deferral accounts, both new and existing, account balances, allocation methodology, disposition periods and related rate riders appropriate?

The Parties agree that this issue is partially settled. The Evidence listed below is pertinent to both the settled and unsettled matters.

Status:	**Partial Settlement**	
Parties:	NOTL Hydro, Energy Probe, VECC	
Evidence:	Item 1	Application: Exhibit 9, Tab 3, Schedule 3
	Item 2	Response to Interrogatory: 5.1-Staff-17
	Item 3	Application: Exhibit 9, Tab 3, Schedule 5
	Item 4	Response to Interrogatory: 9.1-Energy Probe-37
	Item 5	Application: Exhibit 9, Tab 3, Schedule 4
	Item 6	Response to Interrogatory: 9.1-Staff-27
	Item 7	Application: Exhibit 9, Tab 2, Schedule 1
	Item 8	Response to Interrogatory: 5.1-Staff-15
	Item 9	Application: Exhibit 9, Tab 3, Schedule 1
	Item 10	Application: Exhibit 9, Tab 3, Schedule 2
	Item 11	Response to Interrogatories: 9.1-VECC-39/40
	Other Items related to this issue	Response to Interrogatories: 9.1-Staff-26/28

SETTLED MATTERS

Stranded Meter Rate Rider

In the Evidence Item 1, NOTL Hydro proposed an allocation of the remaining net book value of stranded meters using the weighted meter capital cost allocations in NOTL Hydro’s 2009 cost of service rate application, which used the 2006 cost allocation model. In the Evidence Item 2, NOTL Hydro offered an approach using a snapshot of historical purchase prices (circa 2006) which would be reflective of the comparability of installation costs. Using this approach, the allocated weighting of stranded meters would be 44.2% residential, 55.8% GS<50kW as follows:

Allocation Based on Historical Price Snapshot				
Meter Type	**Cost**	**Res**	**GS<50**	**Total**
Regular Residential	$ 39.00	6,597		6,597
Central Meters	$ 99.00	69	187	256
7 Jaw GS<50	$ 295.00		1,066	1,066
Total		6,666	1,253	7,919
Weighted Average Cost		$ 39.62	265.73	
Total Cost		$ 264,133	$ 332,957	$ 597,089
Percentage of Total Cost / Allocated Weighting		**44.2%**	**55.8%**	**100.0%**

The Parties agree that the allocated weighting above properly reflects the relative rate class costs caused by stranded meters and should be used for the calculation of the cost recovery rate riders. The Table below from the Evidence Item 2 reflects this weighting and provides updated calculations of the rate riders. The Parties agree on the rate riders calculation in the Table below.

	<u>Stranded Meters Calculation</u>			
	Capital cost	$ 349,266	*Actual*	
	Accumulated depreciation to Dec 31, 2011	$ 237,184	*Actual*	
	2012 Depreciation	$ 9,836	*Actual*	
	2013 depreciation	$ 9,462	*Forecast*	
A	Net Book Value @ Dec 31, 2013	$ 92,784	*Forecast*	
		Residential	GS< 50 kW	Total
B	Weighted meter capital -per Staff IR17c	$ 264,133	$ 332,957	$ 597,089
C = % of B	Allocated weighting of stranded meters	44.2%	55.8%	100.0%
D = C x A	Net Book Value Segregated by Rate Class	$ 41,045	$ 51,740	$ 92,784
E	Forecast average customers in 2014	7,040	1,304	8,345
F = D / E /12	Rate rider to recover stranded meter costs per Staff IR17c	$ 0.49	$ 3.31	per month
	Recovery period (years)	1	1	
	Number of meters stranded	6,666	1,253	7,919

Account 1572 - Z-Factor – Lightning Storm Cost Recovery

In the Evidence Item 3, NOTL Hydro requested recovery of costs of $55,839 including interest resulting from a natural disaster that occurred on July 19 and 20, 2013. Further details were provided in the Evidence Item 4.

The Parties reviewed the request against the eligibility criteria for recovery set out in Section 3.2.2.1 of the Filing Requirements issued on July 17, 2013 and agreed that the necessary criteria had been met. The Parties carefully re-assessed the extreme severity of the storm as described in the Evidence Item 3 and agree that due to its extra-ordinary nature the event met the definition of a Z-Factor event. The Parties accept the calculation of the balance will be recovered through the requested Deferral and Variance Account rate riders calculated in the EDDVAR model submitted with the Application.

Account 1576 – Accounting Changes Under GAAP

The calculation of Account 1576 in Evidence Item 5 was updated in Evidence Item 6 based on the actual (unaudited) 2013 capital expenditures and disposals and to reflect OEB's updated cost of capital parameters in the "WACC" rate (regulated rate of return) issued on November 25, 2013. The Parties agree that the updated closing balance in Account 1576 is $671,921 as per the Evidence Item 6.

Under Issue 7.5 above, Table 5.1.1 is provided showing an agreed-upon updated NOTL Hydro WACC of 6.61%. With this updated WACC rate of 6.61%, the Parties agree that the amount to be included in the rate rider calculation is $893,861 as per the Table below.

Appendix 2-EE
Account 1576 - Accounting Changes under CGAAP
2013 Changes in Accounting Policies under CGAAP

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013

	2010 Rebasing Year	2011	2012	2013	2014 Rebasing Year	2015	2016	2016	2017
Reporting Basis	CGAAP	IRM	IRM	IRM	CGAAP - ASPE	IRM	IRM	IRM	IRM
Forecast vs. Actual Used in Rebasing Year	Forecast	Actual	Actual	Forecast	Forecast				
				$	$	$	$	$	$
PP&E Values under former CGAAP									
Opening net PP&E - Note 1				21,557,141					
Net Additions - Note 4				1,094,857					
Net Depreciation (amounts should be negative) - Note 4				-1,396,227					
Closing net PP&E (1)				21,255,771					
PP&E Values under revised CGAAP (Starts from 2013)									
Opening net PP&E - Note 1				21,557,141					
Net Additions - Note 4				1,098,857					
Net Depreciation (amounts should be negative) - Note 4				-728,305					
Closing net PP&E (2)				21,927,693					
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP				-671,921					

Effect on Deferral and Variance Account Rate Riders			
Closing balance in Account 1576	- 671,921	**WACC**	6.61%
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	- 221,940	**# of years of rate rider disposition period**	5
Amount included in Deferral and Variance Account Rate Rider Calculation	- 893,861		

Account 1534 – Smart Grid Capital Deferral Account

The Parties accept NOTL Hydro's request in the Evidence Item 7 for the 2013 net capital addition of $237,952 to be included in the calculation of NOTL Hydro's 2014 rate base.

Account 1532 – Renewable Generation Connection OM&A Deferral account

In the Evidence Item 7, NOTL Hydro requested assignment of $17,457 to Provincial Rate Protection, or $17,629 including grossed-up PILs, reflecting a working capital allowance rate of 13% and the capital structure in the Application at that time.

The Parties have reviewed the further details provided in the Evidence Item 8.

Based on the agreed-upon working capital allowance rate of 11% under Issue 7.1 and the agreed-upon capital structure under Issue 9.1 Table 5.1.1 above, the Parties agree upon the updated Direct Benefits/Provincial Amount of $17,610 including grossed-up PILs as follows, with a monthly amount to be paid by the IESO of $1,468:

		2014 Test Year		
			Direct Benefit	Provincial
		Total	6%	94%
Net Fixed Assets (average)		$ -	$ -	$ -
Incremental OM&A (on-going, N/A for Provincial Recovery)		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recovery)		$18,572	$ -	$ 17,457
WCA	11%		$ -	$ 1,920
Rate Base			$ -	$ 1,920
Deemed ST Debt	4%		$ -	$ 77
Deemed LT Debt	56%		$ -	$ 1,075
Deemed Equity	40%		$ -	$ 768
ST Interest	2.11%		$ -	$ 2
LT Interest	4.96%		$ -	$ 53
ROE	9.36%		$ -	$ 72
Cost of Capital Total			$ -	$ 127
OM&A			$ -	$ 17,457
Amortization		$ -	$ -	$ -
Grossed-up PILs			$ -	$ 26
Revenue Requirement			$ -	$ 17,610
Provincial Rate Protection				$ 17,610
Monthly Amount Paid by IESO				$ 1,468

All Other Accounts (excluding 1535 – Smart Grid OM&A Deferral Account)

The Parties accept the requested claims for all other accounts except 1535 as set out in the Evidence Item 7.

Summary - Amounts Claimed

The Parties accept the amounts claimed in the Evidence Item 9 excluding Account 1535 as follows:

- Table 9.3.1: Group 1 Deferral/Variance Accounts – Excluding 1589 GA
  - Total Claim ($814,400)
- Table 9.3.2: Group 2 Deferral/Variance Accounts
  - Total claim $423,244 less $133,025 for Account 1535 = $290,219
- Table 9.3.3: 1589 - Global Adjustment
  - Total claim ($170,381)

Summary – Allocators

The Parties accept the allocators[25] in Table 9.3.4 in the Evidence Item 10 used to assign Group 1 and Group 2 balances to each rate class.

Summary – Balances and Allocations

The Parties accept the allocations of the Group 1 and Group 2 balances to rate classes, based on the allocators referred to above, in the Evidence Item 10 excluding Account 1535 as follows:

- Table 9.3.5: Group 1 Balances and Allocations
- Table 9.3.6: Group 2 Balances and Allocations – Excluding 1568 and 1592
  - but excluding the claim of $133,025 for account 1535
- Table 9.3.7: Group 2 Balances and Allocations - Accounts 1568 and 1592
- Table 9.3.8: RSVA Power Sub-Account Global Adjustment Balance and Allocation

Summary - Rate Rider Calculations

The Parties accept the rate rider calculation methodology underlying Tables 9.3.9 and 9.3.10 in the Evidence Item 10.

[25] I.e. # of customers, metered kWh, metered kW, billed kWh for non-RPP customers, distribution revenue, 1595 recovery share proportion (2011) or 1568 LRAM variance account class allocation ($amounts) .

However, the Parties acknowledge that the rate riders by customer rate class in Table 9.3.9 in the Evidence Item 10 are dependent on the Board decision on the matter not settled regarding Account 1535.

The Parties accept the rate rider calculations in Table 9.3.10: 2014 Non-RPP Global Adjustment Rate Rider by Class in the Evidence Item 10.

Issue 9.1 Conclusion on Settled Matters

The Parties agree that the proposed deferral accounts, both new and existing, account balances, allocation methodology, disposition periods and related rate riders based on the above agreements for the settled matters are appropriate.

MATTER NOT SETTLED

Account 1535 – Smart Grid OM&A Deferral Account

In the Evidence Item 7, NOTL Hydro requested disposition of the December 31, 2013 adjusted balance in Account 1535 plus forecasted interest through April 30, 2014 in the total amount of $133,025. Further details on the smart grid project were provided in the Evidence Item 11.

Issue 9.1 Conclusion on Unsettled Matter

The Parties do not agree on whether the smart grid project was eligible for recording in the Green Energy/Smart Grid variance accounts, and consequently whether the amount that was recorded in Account 1535 is eligible for recovery. The Parties agree that an interpretation of the eligibility requirements by the Board is required to resolve this matter.

The Parties agree that NOTL Hydro and the Intervenors would each make a written submission to the Board on this matter, requesting a Board decision through a written hearing. Notwithstanding that it will be the Board's decision on the form of hearing, oral or written, NOTL Hydro's written Submission is attached to this Settlement Proposal as Appendix 1. The Parties agree that the Intervenors would submit their written Reply Submission within 7 calendar days of submission of this Settlement Proposal.

9.2 Have all impacts of any changes in accounting standards, policies, estimates and adjustments been properly identified, and is the treatment of each of these impacts appropriate?

Status:	**Complete Settlement**	
Supporting Parties:	NOTL Hydro, Energy Probe, VECC	
Evidence:	Item 1	Application: Exhibit 1, Tab 5, Schedule 17
	Other Items related to this issue	There were no Interrogatories related to this Issue

As set out in Evidence Item 1, NOTL Hydro has made changes to the depreciation and capitalization policies effective January 1, 2013, pursuant to the Board's regulatory accounting policy direction in the Board letter of July 17, 2012.

The Parties agree that all impacts of these changes have been properly identified and the treatment of each of these impacts is appropriate.

Appendix 1

Request for Board Decision on the Eligibility of NOTL Hydro's Smart Grid Project for recording in the Green Energy/Smart Grid variance accounts

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

AND IN THE MATTER OF an application by Niagara-on-the-Lake Hydro Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2014

NIAGARA-ON-THE-LAKE HYDRO INC.
PURSUANT TO SETTLEMENT PROPOSAL

Request for Board Decision on the Eligibility of NOTL Hydro's Smart Grid Project for recording in the Green Energy/Smart Grid variance accounts

Filed March 22, 2014

Introduction

Account 1535 – Smart Grid OM&A Deferral Account

In the initial Application: Exhibit 9, Tab 2, Schedule 1, NOTL Hydro requested disposition of the December 31, 2013 adjusted balance in Account 1535 plus forecasted interest through April 30, 2014 in the total amount of $133,025. Further details on the smart grid project were provided in NOTL Hydro's responses to Interrogatories: 9.1-VECC-39/40 and 5.1-Staff-13.

Issue 9.1 Conclusion on Unsettled Matter

The Parties do not agree on whether the smart grid project was eligible for recording in the Green Energy/Smart Grid variance accounts, and consequently whether the amount that was recorded in Account 1535 is eligible for recovery. The Parties agree that an interpretation of the eligibility requirements by the Board is required to resolve this matter.

The Parties agree that NOTL Hydro and the Intervenors would each make a written submission to the Board on this matter, requesting a Board decision through a written hearing. This Appendix 1 to the Settlement Proposal is NOTL Hydro's Submission on this matter.

Background on Smart Grid Project

In 2009, NOTL Hydro decided to proceed with the installation of the Old Town Smart self-healing switch arrangement, having been inspired by the Energy Minister's Green Energy vision and prompted by the OEB's creation of Green Energy/Smart Grid variance accounts. We carefully studied the criteria established for the variance accounts and were convinced that the project qualified and we were advancing Smart Grid public policy established by the government. In 2010, the switches were considered leading edge and utilized smart grid technology to solve a complex situation. Upon completing the system installation in 2011, NOTL Hydro was invited (and accepted) to speak at a North American technical conference in Montreal hosted by Hydro Quebec and share our experience to the audience.

We also note that this project was recognized by Canada Revenue as a valid Science Research and Experimental Data (SRED) project in a 2012 application for a SRED tax credit. The initiative qualified as "Experimental Development" with the purpose "To achieve technological advancement for the purpose of creating new or improving existing materials, devices, products or processes".

The data below shows OM&A expenses related to this project charged to the Account 1535 over the period 2009 to 2012. The associated capital expenses and net capital addition of $237,952 accepted by the Parties under Issues 9.1 are also shown.

Breakdown of 1535 Claim			**1534**	
OM&A to December 31, 2012			Capital to December 2012	
Demonstration projects				
2009 OM&A	$ 10,602		2009	$ 1,483
2010 OM&A	$ 2,208		2010	$ 250,569
2011 OM&A	$ 69,726		2011	$ 21,347
2012 OM&A	$ 2,049		2012	$ -
Total	$ 84,585		Total	$ 273,398
Studies and planning exercises	$ -		Interest	$ 8,796.24
Education and training	$ -		Accumulated Depreciation	$ (44,242.04)
Total OM&A	$ 84,585		Requested net capital addition	$ 237,952
Depreciation to December 31, 2012	$ 44,242			
Interest to april 30, 2014	$ 4,198			
Total	$133,025			

Reason for Recording in Account 1535

The accounts used for recording the costs of the project, 1534 and 1535, were approved by the Board for use by distributors where costs for smart grid initiatives were not included in rates. NOTL Hydro's project was not included in the 2009 COS rebased rates.

NOTL Hydro used these accounts in good faith based on its understanding at the time that the project was eligible as it met the definitions in the Accounting Procedures Handbook as explained in "Frequently Asked Question" Q16 issued December 23, 2010 and extracted in the Addendum at the end of this submission.

The interrogatory 9.1-VECC-39 asked whether the Smart Grid projects were previously approved by the Board. NOTL Hydro's response was that the projects were not previously approved by the Board. However, there appeared to be no requirement in the answer A16 to the "Frequently Asked Question" Q16 for Distributors to seek prior approval of the Board of project's eligibility.

Comment regarding Renewed Regulatory Framework for Electricity

Notwithstanding NOTL Hydro's position on this matter, NOTL Hydro notes that Section 3.3.3 of the Report of the Ontario Energy Board dated October 18, 2012 states as follows:

3.3.3 Treatment of Smart Grid Investments for Rate-setting

Under the integrated approach to planning described in this Report grid-enhancing advanced information and exchange systems and equipment (which are commonly referred to as smart grid) are considered integral to all utility investment. Under this approach, no distinction is made for regulatory purposes between "smart grid" and more traditional investments undertaken by distributors and transmitters – more advanced technologies are so integrated with other activities that such distinctions are not productive.

This approach to smart grid investments and activities will best support the achievement of the objectives of the renewed regulatory framework. It facilitates more fully integrated planning, and will promote economic efficiency and the better alignment of expenditures with cost recovery so as to minimize 'total bill' impacts. It is also more efficient from a regulatory perspective.

NOTL Hydro recognizes that under the renewed regulatory framework, it appears that had the project been implemented since the issuance of the Report, the project would not be eligible.

However, NOTL Hydro completed the project in the period before issuance of the report on the "Renewed Regulatory Framework for Electricity", at which time every indication was that the project was an eligible smart grid project. The business decision to proceed with the project, with its significant OM&A and capital expenditures, was made on that basis, i.e. that the project was an eligible smart grid project.

<u>Summary</u>

NOTL Hydro requests that the Board approve the eligibility of the smart grid project on the basis of the Board policy in effect at the time of the project implementation, without prejudice to the eligibility of smart grid projects under the "Renewed Regulatory Framework for Electricity".

Addendum

<u>Extracts from "Frequently Asked Question" Q16 issued December 23, 2010</u>

ACCOUNTING PROCEDURES HANDBOOK

Frequently Asked Questions

The questions and answers in this section are in relation to matters that, for convenience, are classed as relating generally to the implementation of the *Green Energy and Green Economy Act, 2009* ("GEA"):

Q.16 Can you please provide the Capital, OM&A and Rate Adder Deferral Accounts and their account descriptions in relation to Renewable Generation Connection and Smart Grid Development?

A.16 In its June 16, 2009 "Guidelines: Deemed Conditions of Licence: Distribution System Planning" (G-2009-0087), the Board created four new deferral accounts in the Uniform System of Accounts to allow distributors to begin recording expenditures for certain activities relating to the connection of renewable generation or the development of a smart grid. These deferral accounts were authorized to be used to record qualifying incremental capital investments or OM&A expenses. In this context, incremental means that an investment was not included in previous capital plans approved by the Board or is not funded through current rates.

In its March 25, 2010 "Filing Requirements: Distribution System Plans - Filing under Deemed Conditions of Licence" (EB-2009-0397), the Board created two additional deferral accounts for the recording of amounts collected from ratepayers through any funding adder the Board may approve relating to the connection of renewable generation or the development of a smart grid.

With respect to the smart grid accounts, the Board indicated in both the June, 2009 Guidelines and the March, 2010 Filing Requirements that the legislative and regulatory framework regarding the development and establishment of the smart grid was still under development. Most importantly, the objectives, interoperability requirements and technology standards for the smart grid were being developed. For that reason, the Board limited amounts that can be recorded in the "Smart Grid Capital Deferral Account" and the "Smart Grid OM&A Deferral Account" to expenditures associated with the following activities:

- smart grid demonstration projects;
- smart grid studies and planning exercises; and
- smart grid education and training.

The Board also indicated that expenditures for smart meter-related investments

ACCOUNTING PROCEDURES HANDBOOK

Frequently Asked Questions

and activities, including advanced metering infrastructure, are adequately addressed through other mechanisms and may not be recorded in these GEA deferral accounts.

The six accounts and their descriptions are provided below.

The six accounts referred to in the extract above included:

Account 1534: Smart Grid Capital Deferral Account
Investments related to smart grid demonstration projects should be recorded in this capital deferral Account. This Account should also be used to record the cost of smart grid investments that are undertaken as part of a project to accommodate renewable generation.

The distributor's normal capitalization policies from its last cost of service proceeding should be followed in identifying fixed asset expenditures.

Account 1535: Smart Grid OM&A Deferral Account
Operating, maintenance, amortization and administrative expenses directly related to the following smart grid development activities should be recorded in this operating deferral Account:

- smart grid demonstration projects;
- smart grid studies and planning exercises; and
- smart grid education and training.

This includes expenses associated with preparing the smart grid portion of a "GEA Plan". 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 1534. An investment in a renewable enabling improvement, as defined in the DSC, may incorporate what the distributor believes to be smart grid technologies. In such cases, distributors should allocate any costs associated with the incorporation of smart grid technologies to the smart grid deferral Accounts, with the balance of the costs going to the renewable generation connection deferral Accounts.

Account 1536: Smart Grid Funding Adder Deferral Account
This Account will record the revenue collected through a funding adder approved by the Board related to smart grid development.

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Appendix 2

Response to Energy Probe Clarification Questions

Niagara
On-The-Lake
HYDRO

February 14, 2014

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Toronto ON M4P 1E4

Via RESS and e-mail

Niagara-on-the-Lake Hydro Inc. 2014 COS Rate Application
OEB Case EB-2013-0155

Dear Ms. Walli

Niagara-on-the-Lake Hydro Inc. is pleased to submit the enclosed responses to clarification questions from Energy Probe.

In addition, separate files are being submitted via RESS as per the following questions:

- Question 7 - updated cost allocation model - RUN 2 (Excel)
- Question 8 - updated RRWF (Excel)

Yours truly

Mike Galloway, President
Encl.

Cc
David Macintosh and Randy Aiken for Energy Probe
Michael Janigan, Mark Garner, Bill Harper and Donna Brady for VECC
Stephen Vetsis

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Response to Energy Probe Clarification Questions
2014 Electricity Distribution Rates
Niagara-on-the-Lake Hydro Inc.
EB-2013-0155

Question 1

Ref: 7.1-Energy Probe-19

Please provide revised versions of Tables 2.2.5 and 2.2.6 with all the appropriate links calculated so that all the figures in the tables are shown and calculated appropriately.

Response

Revised versions are provided as Attachment 1, in which the "#REF!" broken links are repaired. These revised versions also have the CCA class for computer hardware changed to CCA class 50 as per the response to Question 5.

-

Question 2

Ref: 7.1-Energy Probe-19 &
1.1-Energy Probe-1

The response to 1.1-Energy Probe-1 shows actual (unaudited) capital expenditures added to rate base for 2013 of $1,322,000. The figure from the revised Table 2.2.5 from 7.1-Energy Probe-19 adds to a total net addition of $1,560,160. Please confirm that the difference is all related to the addition of $237,952 for smart grid investments that NOTL Hydro is proposing to include in rate base beginning in 2014.

Response

NOTL Hydro confirms that the difference is all related to the addition of $237,952 for smart grid investments that NOTL Hydro is proposing to include in rate base beginning in 2014.

The $1,322,000 is a rounded amount, reflecting the actual (unaudited) amount of $1,322,215, which when the $237,952 is added gives the total of $1,560,167 in the updated Table 2.2.5 in the response to Question 1.

Question 3

Ref: 7.1-Energy Probe-19 &
7.1-Energy Probe-20

The response to 7.1-Energy Probe-20 indicates that the increase in contributed capital now forecast for 2014 has no impact on the net additions of $1,285,000 shown in 7.1-Energy Probe-19. However, the total capital additions shown in the 2014 Table 2.2.6 in 7.1-Energy Probe-19 is $1,185,000. Please reconcile and if required, please provide a corrected version of Table 2.2.6 from 7.1-Energy Probe-19.

Response

We regret that the Table 2.2.6 provided in response to 7.1-Energy Probe-19 was not properly checked before submission. The proposed total of 2014 capital additions is unchanged at $1,285,000. A corrected Table 2.2.6 is provided in response to Question 1 above.

Question 4

Ref: 1.1-VECC-1 &
7.1-Energy Probe-23

a) **Please explain the $100,000 difference in the Miscellaneous line for 2014 in the two versions of Table 2.3.2 shown in the responses.**

b) **Table 2.3.2 in the response to 7.l-Energy Probe-23 does not include the Miscellaneous figures for 2009 through 2012 and the totals are not calculated. Please confirm that these figures are the same as found in the table in the response to 1.1-VECC-1.**

Response

a) We regret that the Table 2.3.2 provided in response to 7.1-Energy Probe-23 was not properly checked before submission. The Table 2.3.2 provided in response to 1.1-VECC-1, which showed 2014 Miscellaneous at $105,000, not $5,000, was correct. The proposed total of 2014 capital additions is unchanged at $1,285,000.

b) NOTL Hydro confirms that the miscellaneous figures for 2009 through 2012 are the same as found in the table in the response to 1.1-VECC-1.

Question 5

Ref: Exhibit 4, Tab 4, Schedule 2 &
7.7-Staff-18 &
7.1-Energy Probe-22

a) Please explain why computer hardware was included in CCA class 10 rather than in CCA class 50 in Tables 4.4.3 and 4.4.5, respectively for 2013 and 2014.

b) In the response to 7.7-Staff-18, the listing of the changes does not show any line item for changes to the CCA available in 2014 as a result of the actual (unaudited) capital expenditures in 2013 and the change for 2014 associated with the $30,000 re-allocated as noted in 7.1-Energy Probe-22. Did NOTL take into account the change in the CCA in updating the RRWF?

c) Please provide updated versions of Tables 4.4.3 and 4.4.5 that reflect both the $30,000 change noted in 7.1-Energy Probe-22 and the correct allocation of computer hardware from CCA class 10 to 50 in both 2013 and 2014.

Response

a) We have consulted today with our KPMG tax advisors, who have confirmed that historical computer hardware was included in CCA class 50 in NOTL Hydro's 2012 and earlier tax returns. NOTL Hydro staff had included the 2013 and 2014 computer hardware additions in CCA class 10 in the application based on the OEB Attachment 2-BA model as shown below and on the generic CRA description of class 10, without consulting with KPMG. We accept that it appears that the class should be 50 and have made the change accordingly.

Appendix 2-BA
Fixed Asset Continuity Schedule - CGAAP/ASPE/USGAAP

Year

			Cost				Acc	
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Add
12	1611	Computer Software (Formally known as Account 1925)				$ -		
CEC	1612	Land Rights (Formally known as Account 1906)				$ -		
N/A	1805	Land				$ -		
47	1808	Buildings				$ -		
13	1810	Leasehold Improvements				$ -		
47	1815	Transformer Station Equipment >50 kV				$ -		
47	1820	Distribution Station Equipment <50 kV				$ -		
47	1825	Storage Battery Equipment				$ -		
47	1830	Poles, Towers & Fixtures				$ -		
47	1835	Overhead Conductors & Devices				$ -		
47	1840	Underground Conduit				$ -		
47	1845	Underground Conductors & Devices				$ -		
47	1850	Line Transformers				$ -		
47	1855	Services (Overhead & Underground)				$ -		
47	1860	Meters				$ -		
47	1860	Meters (Smart Meters)				$ -		
N/A	1905	Land				$ -		
47	1908	Buildings & Fixtures				$ -		
13	1910	Leasehold Improvements				$ -		
8	1915	Office Furniture & Equipment (10 years)				$ -		
8	1915	Office Furniture & Equipment (5 years)				$ -		
10	1920	Computer Equipment - Hardware				$ -		
[illegible]	[illegible]	Computer Equip.-Hardware(Post Mar				$		

b) While not listed in the response to 7.7-Staff-18, NOTL Hydro did take account of the actual (unaudited) 2013 capital expenditures and the $30,000 re-allocation in 2014 in updating the RRWF.

c) Updated Tables 4.4.3 and 4.4.5 are provided below that reflect both the $30,000 change noted in 7.1-Energy Probe-22 (as they did before) and the re-allocation of computer hardware from CCA class 10 to 50 in 2013 & 2014.

Table 4.4.3 (updated)

CCA Continuity Schedule (2013)

Class	Class Description	UCC Prior Year Ending Balance	Additions	Dispositions	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 22-Feb-2005	10,092,052	0	0	10,092,052	0	10,092,052	4%	403,682	9,688,370
1b	Buildings	96,558	0	0	96,558	0	96,558	6%	5,793	90,765
2	Distribution System - pre 1988	3,349,969	0	0	3,349,969	0	3,349,969	6%	200,998	3,148,971
6	Buildings - after 1990	3,670	0	0	3,670	0	3,670	10%	367	3,303
8	General Office/Stores Equip	385,575	5,751	0	391,326	2,875	388,450	20%	77,690	313,636
10	Computer Hardware/ Vehicles	353,014	53,681	35,341	371,354	9,170	362,184	30%	108,655	262,699
10.1	Certain Automobiles		0	0	0	0	0	30%	0	0
12	Computer Software	57,669	104,895	0	162,564	52,448	110,117	100%	110,117	52,448
3	Buildings - pre 1990		0	0	0	0	0	5%	0	0
			0	0	0	0	0		0	0
13 3	Lease # 3		0	0	0	0	0		0	0
13 4	Lease # 4		0	0	0	0	0		0	0
14	Franchise		0	0	0	0	0		0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	25,277	0	0	25,277	0	25,277	8%	2,022	23,255
43.1	Certain Energy-Efficient Electrical Generating Equipment		0	0	0	0	0	30%	0	0
45	Computers & Systems Hardware acq'd post Mar 22/04	563	0	0	563	0	563	45%	253	310
50	Computers & Systems Hardware acq'd post Mar 19/07	16,642	38,762	0	55,404	19,381	36,023	55%	19,813	35,591
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)		0	0	0	0	0	30%	0	0
47	Distribution System - post 22-Feb-2005	9,501,812	1,357,079	425,970	10,432,921	465,554	9,967,366	8%	797,389	9,635,532
	SUB-TOTAL - UCC	**23,882,801**	**1,560,167**	**461,310**	**24,981,658**	**549,429**	**24,432,230**		**1,726,780**	**23,254,878**

CEC	Incorporation costs	10,564
CEC	Land Rights	
CEC	FMV Bump-up	
	SUB-TOTAL - CEC	**10,564**

Table 4.4.5 (updated)

CCA Continuity Schedule (2014)

Class	Class Description	UCC Prior Year Ending Balance	Additions	Dispositions	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 22-Feb-2005	9,688,370	0	0	9,688,370	0	9,688,370	4%	387,535	9,300,835
1b	Buildings	90,765	0	0	90,765	0	90,765	6%	5,446	85,319
2	Distribution System - pre 1988	3,148,971	0	0	3,148,971	0	3,148,971	6%	188,938	2,960,033
6	Buildings - after 1990	3,303	0	0	3,303	0	3,303	10%	330	2,973
8	General Office/Stores Equip	313,636	15,000	0	328,636	7,500	321,136	20%	64,227	264,409
10	Computer Hardware/ Vehicles	262,699	0	0	262,699	0	262,699	30%	78,810	183,889
10.1	Certain Automobiles	0	0	0	0	0	0	30%	0	0
12	Computer Software	52,448	190,000	0	242,448	95,000	147,448	100%	147,448	95,000
3	Buildings - pre 1990	0	0	0	0	0	0	5%	0	0
		0	0	0	0	0	0	0%	0	0
13 3	Lease # 3	0	0	0	0	0	0		0	0
13 4	Lease # 4	0	0	0	0	0	0		0	0
14	Franchise	0	0	0	0	0	0		0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	23,255	0	0	23,255	0	23,255	8%	1,860	21,394
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0	0	0	30%	0	0
45	Computers & Systems Hardware acq'd post Mar 22/04	310	0	0	310	0	310	45%	139	170
50	Computers & Systems Hardware acq'd post Mar 19/07	35,591	5,000	0	40,591	2,500	38,091	55%	20,950	19,641
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0	0	0	30%	0	0
47	Distribution System - post 22-Feb-2005	9,635,532	1,075,000	477,000	10,233,532	299,000	9,934,532	8%	794,763	9,438,769
	SUB-TOTAL - UCC	**23,254,878**	**1,285,000**	**477,000**	**24,062,878**	**404,000**	**23,658,878**		**1,690,446**	**22,372,432**

CEC	Goodwill	10,564
CEC	Land Rights	0
CEC	FMV Bump-up	0
	SUB-TOTAL - CEC	**10,564**

Question 6

Ref: 7.5-Energy Probe-30

a) What is the expected term of the $300,000 loan that is forecast to be required in 2014?

b) What is the current interest rate available from Infrastructure Ontario for a loan of the term noted in the response to part (a) above?

Response

a) As shown in Table 5.1.2 – Debt Instruments 2009-2014, Exhibit 5 Tab 1 Schedule 2, Page 4, the expected term is 10 years.

b) We have contacted Infrastructure Ontario today (February 13th) and their response is shown below:

"Infrastructure Ontario's "indicative" interest rates are posted on our web site and can viewed any time by using this link:

http://www.infrastructureontario.ca/Templates/RateForm.aspx?ekfrm=2147483942&langtype=1033&sector=ldc

The "indicative" 10 year interest rates on February 13, 2014 are as follows:

Serial loan - 3.08%

Amortizer loan - 3.18%"

Question 7

Ref: 8.2-VECC-34

The response to part (a) states that NOTL Hydro will maintain the basic service in perpetuity for the USL, GS < 50 and GS > 50 rate classes, but the response to part (b) states that NOTL Hydro does not maintain/repair service assets for other rates classes, referring to non-residential classes. Please explain.

Response

We have incorrectly calculated the weightings for Table 7.1.1 given that we do maintain services for GS<50 and USL that have an ampacity of 200 or less. The corrected services weighting factors replacing the Table 7.1.1 in the application are as follows:

- Residential 1.00
- GS<50 0.76
- USL 0.37
- GS> 50 0.00
- Street Lights 0.00

An updated cost allocation model (designated as RUN 2) is provided via RESS. Updated sheets I6, I8, O1 and O2 are provided as Attachment 2.

Updated bill impacts are provided as Attachment 3.

Question 8

Ref: 7.7-Energy Probe-33

Please provide an update to the response, including an update to the tracking sheet and a live Excel spreadsheet for the RRWF, to reflect any changes or corrections as a result of these questions.

Response

An updated tracking sheet is provided below.

Topic	Interrogatory Response	RRWF reference
Specific Service Charges increase	7.1-VECC-22	See RRWF 3. Data Input Sheet, Note 13
O&M reduction	4.2-VECC-15	See RRWF 3. Data Input Sheet, Note 14
1576 update	9.1-Staff-27	n/a
Capital Parameters update	7.5-Energy Probe-31	-
Truck disposals update	7.1-Energy Probe-22	See RRWF 3. Data Input Sheet, Note 10
Capital Contributions update	7.1-Energy Probe-20	-
FA Continuity update	7.1-Energy Probe-20	See RRWF 3. Data Input Sheet, Note 10 and Note 15
Cost of Power update	7.1-Energy Probe-24	See RRWF 3. Data Input Sheet, Note 12
RTSR update	8.5-VECC-38	n/a

Updates

Computer hardware CCA class change	Energy Probe – Clarification Question 5	See RRWF 3. Data Input Sheet, Note 16
Cost allocation - Service Weighting Factors	Energy Probe – Clarification Question 7	n/a

An updated Table 6.1.1 is provided below.

Table 6.1.1 Revenue Sufficiency (updated per Energy Probe Questions)

	A	B	C	D
5	**Description**	**2013 Bridge Actual**	**2014 Test Existing Rates**	**2014 Test - Required Revenue**
6	**Revenue**			
7	Revenue Deficiency			(256,933)
8	Distribution Revenue	5,059,576	4,844,096	4,844,096
9	Other Operating Revenue (Net)	(396,410)	260,781	260,781
10	**Total Revenue**	**4,663,166**	**5,104,877**	**4,847,944**
11				
12	**Costs and Expenses**			
13	Administrative & General, Billing & Collecting	1,221,443	1,267,085	1,267,085
14	Operation & Maintenance	960,446	948,177	948,177
15	Depreciation & Amortization	985,790	911,109	911,109
16	Property Taxes	28,146	28,596	28,596
17	Return on PP&E			0
18	Deemed Interest	871,411	723,666	723,666
19	**Total Costs and Expenses**	**4,067,237**	**3,878,635**	**3,878,635**
20				
21	**Utility Income Before Income Taxes**	**595,929**	**1,226,242**	**969,309**
22				
23	**Income Taxes:**			
24	Corporate Income Taxes	1,206	75,420	35,595
25	**Total Income Taxes**	**1,206**	**75,420**	**35,595**
26				
27	**Utility Net Income**	**594,723**	**1,150,823**	**933,714**
28				
29				
30	**Income Tax Expense Calculation:**			
31	Accounting Income	595,929	1,226,242	969,309
32	Tax Adjustments to Accounting Income	(542,990)	(662,245)	(662,245)
33	**Taxable Income**	**52,939**	**563,997**	**307,064**
34	**Income tax expense before credits**	**8,206**	**87,420**	**47,595**
35	**Credits**	**7,000**	**12,000**	**12,000**
36	**Income Tax Expense**	1,206	75,420	35,595
37	**Tax Rate**	15.50%	15.50%	15.50%
38				
39	**Actual Return on Rate Base:**			
40	Rate Base	24,444,044	24,938,951	24,938,951
41				
42	Interest Expense	871,411	723,666	723,666
43	Net Income	594,723	1,150,823	933,714
44	**Total Actual Return on Rate Base**	**1,466,135**	**1,874,489**	**1,657,381**
45				
46	**Actual Return on Rate Base**	6.00%	7.52%	6.65%
47				
48	**Required Return on Rate Base:**			
49	Rate Base	24,444,044	24,938,951	24,938,951
50				
51	**Return Rates:**			
52	Return on Debt (Weighted)	5.94%	4.84%	4.84%
53	Return on Equity	8.01%	9.36%	9.36%
54				
55	Deemed Interest Expense	871,411	723,666	723,666
56	Return On Equity	783,187	933,714	933,714
57	**Total Return**	**1,654,599**	**1,657,381**	**1,657,381**
58				
59	**Expected Return on Rate Base**	6.77%	6.65%	6.65%
60				
61	**Revenue Deficiency After Tax**	**188,464**	**(217,108)**	**0**
62	**Revenue Deficiency Before Tax**	**223,034**	**(256,933)**	**0**
63				
64				
65	**Tax Exhibit**			**2014**
66				
67	Deemed Utility Income			933,714
68	Tax Adjustments to Accounting Income			(662,245)
69	**Taxable Income prior to adjusting revenue to PILs**			**271,469**
70	Tax Rate			15.50%
71	Total PILs before gross up before tax credits			**42,078**
72	Tax Credits			**12,000**
73	Total PILs before gross up after tax credits			**30,078**
74	**Grossed up PILs**			**35,595**
75				

An updated RRWF is provided below as Attachment 4[1]. A live Excel RRWF is submitted via RESS.

[1] "Supplementary Interrogatory Responses" heading selected to refer to "Clarification Questions"

Attachment 1

Updated Tables 2.2.5 and 2.2.6

For Response to Energy Probe Question 1

File Number:	EB-2013-0155
Exhibit:	Exhibit 2
Tab:	2
Schedule:	1
Page:	1
Date:	February 14, 2014

Appendix 2-BA
Fixed Asset Continuity Schedule - CGAAP/ASPE/USGAAP

Year **2013**

			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	$ 258,134	$ -	$ -	$ 258,134	$ -	$ -	$ -	$ -	$ 258,134
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Trans Stn Equip >50 Kv-Other-York	$ 1,915,162	$ -	$ -	$ 1,915,162	-$ 449,087	-$ 32,129	$ -	-$ 481,216	$ 1,433,946
47	1815	Trans Stn Equip >50 Kv-Tx - York	$ 827,000	$ -	$ -	$ 827,000	-$ 196,413	-$ 17,763	$ -	-$ 214,176	$ 612,824
47	1815	Trans Stn Equip >50 Kv-Other-Conc 5	$ 2,010,750	$ -	$ -	$ 2,010,750	-$ 346,145	-$ 34,587	$ -	-$ 380,732	$ 1,630,018
47	1815	Trans Stn Equip >50 Kv-Tx -Conc 5	$ 670,096	$ -	$ -	$ 670,096	-$ 125,643	-$ 14,519	$ -	-$ 140,162	$ 529,934
47	1820	Distribution Station Equipment <50 kV	$ 160,630	$ -	$ -	$ 160,630	-$ 112,703	-$ 47,927	$ -	-$ 160,630	-$ 0
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 5,094,579	$ 252,116	-$ 29,886	$ 5,316,810	-$ 2,964,062	-$ 77,879	$ 28,188	-$ 3,013,753	$ 2,303,057
47	1835	Overhead Conductors & Devices	$ 6,652,606	$ 132,181	-$ 27,867	$ 6,756,920	-$ 3,813,945	-$ 69,233	$ 26,009	-$ 3,857,169	$ 2,899,751
47	1840	Underground Conduit	$ 4,988,108	$ 261,599	$ -	$ 5,249,706	-$ 2,282,798	-$ 52,842	$ -	-$ 2,335,640	$ 2,914,066
47	1845	Underground Conductors & Devices	$ 8,810,757	$ 507,775	$ -	$ 9,318,533	-$ 4,642,700	-$ 145,230	$ -	-$ 4,787,931	$ 4,530,602
47	1850	Line Transformers	$ 7,860,290	$ 234,149	-$ 18,951	$ 8,075,489	-$ 3,915,307	-$ 122,411	$ 14,532	-$ 4,023,187	$ 4,052,302
47	1855	Services - Overhead	$ 575,400	$ 30,148	$ -	$ 605,548	-$ 132,293	-$ 8,302	$ -	-$ 140,595	$ 464,953
47	1855	Services - Underground	$ 2,308,811	$ 225,648	$ -	$ 2,534,459	-$ 629,751	-$ 46,018	$ -	-$ 675,769	$ 1,858,690
47	1860	Meters - CT/PTs component	$ 451,702	$ -	$ 1,255	$ 452,958	-$ 320,713	-$ 4,483	$ -	-$ 325,197	$ 127,761
47	1860	Meters - Other component	$ 280,257	$ 27,481	-$ 1,255	$ 306,482	-$ 174,998	-$ 8,340	$ -	-$ 183,338	$ 123,145
47	1860	Meters - Stranded	$ 349,266	$ -	-$ 349,266	$ -	-$ 247,020	-$ 9,462	$ 256,482	$ -	$ -
47	1860	Meters (Smart Meters)	$ 1,699,032	$ 19,478	$ -	$ 1,718,509	-$ 281,584	-$ 113,918	$ -	-$ 395,502	$ 1,323,008
N/A	1905	Land	$ 49,000	$ -	$ -	$ 49,000	$ -	$ -	$ -	$ -	$ 49,000
47	1908	Buildings & Fixtures - HQ	$ 1,044,958	$ 1,060	$ -	$ 1,046,018	-$ 366,588	-$ 17,268	$ -	-$ 383,856	$ 662,162
47	1908	Buildings & Fixtures - PCB shed	$ 8,690	$ -	$ -	$ 8,690	-$ 7,085	-$ 357	$ -	-$ 7,442	$ 1,249
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 214,125	$ 2,509	$ -	$ 216,633	-$ 170,861	-$ 8,736	$ -	-$ 179,597	$ 37,037
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equipment - Hardware	$ 376,140	$ 38,762	$ -	$ 414,902	-$ 337,918	-$ 33,090	$ -	-$ 371,008	$ 43,894
12	1925	Computer Software	$ 1,711,417	$ 104,895	$ -	$ 1,816,312	-$ 1,545,851	-$ 118,784	$ -	-$ 1,664,636	$ 151,677
12	1925	Computer Software (CIS TOU upgrade)	$ 170,000	$ -	$ -	$ 170,000	-$ 51,000	-$ 34,000	$ -	-$ 85,000	$ 85,000
10	1930	Transportation Equipment<3 tons	$ 141,065	$ 53,681	-$ 35,341	$ 159,405	-$ 129,358	-$ 14,054	$ 35,341	-$ 108,071	$ 51,334
10	1930	Transportation Equipment>3 tons	$ 940,581	$ -	$ -	$ 940,581	-$ 317,468	-$ 79,761	$ -	-$ 397,229	$ 543,352
10	1930	Transportation Equipment-trailer	$ 38,458	$ -	$ -	$ 38,458	-$ 38,458	$ -	$ -	-$ 38,458	$ -
10	1930	Transportation Equipment-old account									
8	1935	Stores Equipment	$ 24,684	$ -	$ -	$ 24,684	-$ 18,375	-$ 1,043	$ -	-$ 19,417	$ 5,266
8	1940	Tools, Shop & Garage Equipment	$ 463,313	$ 3,242	$ -	$ 466,555	-$ 400,141	-$ 24,382	$ -	-$ 424,524	$ 42,031
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 54,383	$ -	$ -	$ 54,383	-$ 38,445	-$ 3,991	$ -	-$ 42,436	$ 11,947
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises				$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises				$ -				$ -	$ -
47	1980	System Supervisor Equipment	$ 325,968	$ -	$ -	$ 325,968	-$ 215,219	-$ 51,595	$ -	-$ 266,814	$ 59,154
47	1980	System Supervisor Equipment - smartgrid	$ -	$ 237,952	$ -	$ 237,952	$ -	-$ 18,227	$ -	-$ 18,227	$ 219,726
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants - Poles	-$ 231,683	-$ 6,683	$ -	-$ 238,366	$ 62,117	$ 4,473	$ -	$ 66,591	-$ 171,775
47	1995	Contributions & Grants - Wires	-$ 235,221	$ -	$ -	-$ 235,221	$ 71,105	$ 3,107	$ -	$ 74,212	-$ 161,009
47	1995	Contributions & Grants - OH services	-$ 137,549	-$ 9,014	$ -	-$ 146,562	$ 49,028	$ 1,803	$ -	$ 50,831	-$ 95,731
47	1995	Contributions & Grants - Conduit	-$ 781,544	-$ 97,678	$ -	-$ 879,222	$ 203,427	$ 10,529	$ -	$ 213,956	-$ 665,266
47	1995	Contributions & Grants - UG conductor	-$ 1,644,448	-$ 144,330	$ -	-$ 1,788,778	$ 553,918	$ 31,077	$ -	$ 584,995	-$ 1,203,783
47	1995	Contributions & Grants - UG services	-$ 1,435,421	-$ 171,231	$ -	-$ 1,606,653	$ 403,556	$ 28,722	$ -	$ 432,278	-$ 1,174,374
47	1995	Contributions & Grants - Transformers	-$ 2,140,168	-$ 143,573	$ -	-$ 2,283,741	$ 630,529	$ 41,264	$ -	$ 671,793	-$ 1,611,948
47	1995	Contributions & Grants - Building	-$ 13,000	$ -	$ -	-$ 13,000	$ 3,380	$ 205	$ -	$ 3,585	-$ 9,415
47	1995	Contributions & Grants - Meters	-$ 7,344	$ -	$ -	-$ 7,344	$ 3,024	$ 294	$ -	$ 3,318	-$ 4,026
47	1995	Contributions & Grants - Trucks	-$ 9,722	$ -	$ -	-$ 9,722	$ 9,722	$ -	$ -	$ 9,722	$ 0
	etc.					$ -				$ -	$ -
						$ -				$ -	$ -
		Sub-Total	**$ 43,839,262**	**$ 1,560,167**	**-$ 461,310**	**$ 44,938,119**	**-$ 22,282,121**	**-$ 1,088,857**	**$ 360,551**	**-$ 23,010,427**	**$ 21,927,693**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 43,839,262**	**$ 1,560,167**	**-$ 461,310**	**$ 44,938,119**	**-$ 22,282,121**	**-$ 1,088,857**	**$ 360,551**	**-$ 23,010,427**	**$ 21,927,693**

10		Transportation
8		Stores Equipment

Less: Fully Allocated Depreciation	
Transportation	-$ 93,814
Stores Equipment	-$ 1,043
Net Depreciation	-$ 994,000

g

File Number:	EB-2013-0155
Exhibit:	Exhibit 2
Tab:	2
Schedule:	1
Page:	1
Date:	February 14, 2014

Appendix 2-BA
Fixed Asset Continuity Schedule - CGAAP/ASPE/USGAAP

Year 2014

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
N/A	1805	Land	$ 258,134	$ -	$ -	$ 258,134	$ -	$ -	$ -	$ -	$ 258,134
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Trans Stn Equip >50 Kv-Other-York	$ 1,915,162	$ 5,000	$ -	$ 1,920,162	-$ 481,216	-$ 32,174	$ -	-$ 513,390	$ 1,406,772
47	1815	Trans Stn Equip >50 Kv-Tx - York	$ 827,000	$ -	$ -	$ 827,000	-$ 214,176	-$ 17,763	$ -	-$ 231,939	$ 595,061
47	1815	Trans Stn Equip >50 Kv-Other-Conc 5	$ 2,010,750	$ -	$ -	$ 2,010,750	-$ 380,732	-$ 34,587	$ -	-$ 415,319	$ 1,595,431
47	1815	Trans Stn Equip >50 Kv-Tx -Conc 5	$ 670,096	$ -	$ -	$ 670,096	-$ 140,162	-$ 14,519	$ -	-$ 154,681	$ 515,416
47	1820	Distribution Station Equipment <50 kV	$ 160,630	$ -	$ -	$ 160,630	-$ 160,630	$ -	$ -	-$ 160,630	-$ 0
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 5,316,810	$ 224,000	-$ 182,000	$ 5,358,810	-$ 3,013,753	-$ 83,150	$ 182,000	-$ 2,914,903	$ 2,443,906
47	1835	Overhead Conductors & Devices	$ 6,756,920	$ 312,750	-$ 215,000	$ 6,854,670	-$ 3,857,169	-$ 72,925	$ 215,000	-$ 3,715,094	$ 3,139,576
47	1840	Underground Conduit	$ 5,249,706	$ 222,000	$ -	$ 5,471,706	-$ 2,335,640	-$ 56,562	$ -	-$ 2,392,202	$ 3,079,504
47	1845	Underground Conductors & Devices	$ 9,318,533	$ 285,000	$ -	$ 9,603,533	-$ 4,787,931	-$ 154,039	$ -	-$ 4,941,969	$ 4,661,563
47	1850	Line Transformers	$ 8,075,489	$ 241,250	-$ 80,000	$ 8,236,739	-$ 4,023,187	-$ 127,311	$ 50,000	-$ 4,100,497	$ 4,136,242
47	1855	Services - Overhead	$ 605,548	$ 25,000	$ -	$ 630,548	-$ 140,595	-$ 8,762	$ -	-$ 149,357	$ 481,191
47	1855	Services - Underground	$ 2,534,459	$ 215,000	$ -	$ 2,749,459	-$ 675,769	-$ 50,915	$ -	-$ 726,684	$ 2,022,776
47	1860	Meters - CT/PTs component	$ 452,958	$ -	$ 1,255	$ 454,213	-$ 325,197	-$ 4,483	$ -	-$ 329,680	$ 124,533
47	1860	Meters - Other component	$ 306,482	$ 30,000	-$ 1,255	$ 335,227	-$ 183,338	-$ 9,181	$ -	-$ 192,519	$ 142,708
47	1860	Meters - Stranded	$ -			$ -	$ -			$ -	$ -
47	1860	Meters (Smart Meters)	$ 1,718,509	$ 10,000	$ -	$ 1,728,509	-$ 395,502	-$ 114,901	$ -	-$ 510,402	$ 1,218,107
N/A	1905	Land	$ 49,000	$ -	$ -	$ 49,000	$ -	$ -	$ -	$ -	$ 49,000
47	1908	Buildings & Fixtures - HQ	$ 1,046,018	$ 5,000	$ -	$ 1,051,018	-$ 383,856	-$ 17,319	$ -	-$ 401,175	$ 649,843
47	1908	Buildings & Fixtures - PCB Shed	$ 8,690	$ -	$ -	$ 8,690	-$ 7,442	-$ 357	$ -	-$ 7,798	$ 892
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 216,633	$ 5,000	$ -	$ 221,633	-$ 179,597	-$ 8,428	$ -	-$ 188,025	$ 33,609
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equipment - Hardware	$ 414,902	$ 5,000	$ -	$ 419,902	-$ 371,008	-$ 22,511	$ -	-$ 393,519	$ 26,383
12	1925	Computer Software	$ 1,816,312	$ 190,000	$ -	$ 2,006,312	-$ 1,664,636	-$ 111,673	$ -	-$ 1,776,308	$ 230,004
12	1925	Computer Software (CIS TOU upgrade)	$ 170,000	$ -	$ -	$ 170,000	-$ 85,000	-$ 34,000	$ -	-$ 119,000	$ 51,000
10	1930	Transportation Equipment<3 tons	$ 159,405	$ -	$ -	$ 159,405	-$ 108,071	-$ 13,468	$ -	-$ 121,539	$ 37,866
10	1930	Transportation Equipment>3 tons	$ 940,581	$ -	$ -	$ 940,581	-$ 397,229	-$ 79,761	$ -	-$ 476,989	$ 463,592
10	1930	Transportation Equipment-trailer	$ 38,458	$ -	$ -	$ 38,458	-$ 38,458	$ -	$ -	-$ 38,458	$ -
10	1930	Transportation Equipment-old account				$ -				$ -	$ -
8	1935	Stores Equipment	$ 24,684	$ 5,000	$ -	$ 29,684	-$ 19,417	-$ 1,293	$ -	-$ 20,710	$ 8,974
8	1940	Tools, Shop & Garage Equipment	$ 466,555	$ 5,000	$ -	$ 471,555	-$ 424,524	-$ 15,302	$ -	-$ 439,826	$ 31,729
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 54,383	$ -	$ -	$ 54,383	-$ 42,436	-$ 3,991	$ -	-$ 46,427	$ 7,956
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -		$ -	$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 325,968	$ -	$ -	$ 325,968	-$ 266,814	-$ 31,797	$ -	-$ 298,610	$ 27,357
47	1980	System Supervisor Equipment - smartgrid	$ 237,952	$ -	$ -	$ 237,952	-$ 18,227	-$ 18,227	$ -	-$ 36,453	$ 201,499
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants - Poles	-$ 238,366	-$ 30,000	$ -	-$ 268,366	$ 66,591	$ 4,881	$ -	$ 71,472	-$ 196,894
47	1995	Contributions & Grants - Wires	-$ 235,221	-$ 5,000	$ -	-$ 240,221	$ 74,212	$ 3,149	$ -	$ 77,361	-$ 162,860
47	1995	Contributions & Grants - OH services	-$ 146,562	-$ 10,000	$ -	-$ 156,562	$ 50,831	$ 3,045	$ -	$ 53,876	-$ 102,686
47	1995	Contributions & Grants - Conduit	-$ 879,222	-$ 90,000	$ -	-$ 969,222	$ 213,956	$ 11,972	$ -	$ 225,928	-$ 743,294
47	1995	Contributions & Grants - UG conductor	-$ 1,788,778	-$ 120,000	$ -	-$ 1,908,778	$ 584,995	$ 34,014	$ -	$ 619,009	-$ 1,289,769
47	1995	Contributions & Grants - UG services	-$ 1,606,653	-$ 140,000	$ -	-$ 1,746,653	$ 432,278	$ 32,180	$ -	$ 464,458	-$ 1,282,194
47	1995	Contributions & Grants - Transformers	-$ 2,283,741	-$ 105,000	$ -	-$ 2,388,741	$ 671,793	$ 44,026	$ -	$ 715,819	-$ 1,672,923
47	1995	Contributions & Grants - Building	-$ 13,000	$ -	$ -	-$ 13,000	$ 3,585	$ 205	$ -	$ 3,790	-$ 9,210
47	1995	Contributions & Grants - Meters	-$ 7,344	$ -	$ -	-$ 7,344	$ 3,318	$ 294	$ -	$ 3,612	-$ 3,732
47	1995	Contributions & Grants - Trucks	-$ 9,722	$ -	$ -	-$ 9,722	$ 9,722	$ -	$ -	$ 9,722	$ 0
	etc.					$ -				$ -	$ -
						$ -				$ -	$ -
		Sub-Total	**$ 44,938,119**	**$ 1,285,000**	**-$ 477,000**	**$ 45,746,119**	**-$ 23,010,427**	**-$ 1,005,631**	**$ 447,000**	**-$ 23,569,057**	**$ 22,177,062**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 44,938,119**	**$ 1,285,000**	**-$ 477,000**	**$ 45,746,119**	**-$ 23,010,427**	**-$ 1,005,631**	**$ 447,000**	**-$ 23,569,057**	**$ 22,177,062**

10		Transportation
8		Stores Equipment

Less: Fully Allocated Depreciation	
Transportation	-$ 93,228
Stores Equipment	-$ 1,293
Net Depreciation	-$ 911,109

Attachment 2

Updated Cost Allocation – RUN 2

For Response to Energy Probe Question 7

2014 Cost Allocation Model

EB-2013-0155

Sheet I6.1 Revenue Worksheet - RUN 2 after IRRs and Clarification Qs

Total kWhs from Load Forecast	187,976,750
Total kWs from Load Forecast	202,686
Deficiency/sufficiency (RRWF 8. cell F51)	256,933
Miscellaneous Revenue (RRWF 5. cell F48)	260,781

			1	2	3	7	9
	ID	**Total**	**Residential**	**General Service less than 50 kW**	**General Service 50 to 4,999 kW**	**Street Lighting**	**Unmetered Scattered Load**
Billing Data							
Forecast kWh	**CEN**	187,976,750	67,875,319	37,894,182	80,718,464	1,248,464	240,322
Forecast kW	**CDEM**	202,686	-	-	199,309	3,377	-
Forecast kW, included in CDEM, of customers receiving line transformer allowance		39,096	-	-	39,096	-	-
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-					
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	187,976,750	67,875,319	37,894,182	80,718,464	1,248,464	240,322
Existing Monthly Charge			$18.31	$45.97	$328.41	$4.98	$54.31
Existing Distribution kWh Rate			$0.0129	$0.0138			$0.0163
Existing Distribution kW Rate					$2.5664	$19.4795	
Existing TOA Rate					$0.56		
Additional Charges							
Distribution Revenue from Rates		$4,865,989	$2,422,493	$1,242,401	$995,892	$187,134	$18,069
Transformer Ownership Allowance		$21,894	$0	$0	$21,894	$0	$0
Net Class Revenue	**CREV**	$4,844,096	$2,422,493	$1,242,401	$973,998	$187,134	$18,069

2014 Cost Allocation Model

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Sheet I6.2 Customer Data Worksheet - RUN 2 after IRRs and Clarification Qs

	ID	Total	1 Residential	2 General Service less than 50 kW	3 General Service 50 to 4,999 kW	7 Street Lighting	9 Unmetered Scattered Load
Billing Data							
Bad Debt 3 Year Historical Average	BDHA	$18,040	$13,645	$4,395	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$44,649	$28,933	$9,228	$6,141	$302	$45
Number of Bills	CNB	101,930	84,484	15,650.67	1,475	60	261
Number of Devices			7,040	1,304	123	2,031	22
Number of Connections (Unmetered)	CCON	2,052				2,031	22
Total Number of Customers	CCA	8,494	7,040	1,304	123	5	22
Bulk Customer Base	CCB	-	-	-	-	-	-
Primary Customer Base	CCP	10,520	7,040	1,304	123	2,031	22
Line Transformer Customer Base	CCLT	10,511	7,040	1,304	114	2,031	22
Secondary Customer Base	CCS	9,325	6,548	707	18	2,031	22
Weighted - Services	CWCS	7,092	6,548	537	7	-	-
Weighted Meter -Capital	CWMC	2,526,900	1,865,292	495,677	165,931	-	-
Weighted Meter Reading	CWMR	10,724	7,040	1,304	2,254	125	-
Weighted Bills	CWNB	101,834	84,484	15,621	1,479	47	203

Bad Debt Data

Historic Year:	2010	9,729	5,691	4,037	-	-	-
Historic Year:	2011	15,867	15,544	324	-	-	-
Historic Year:	2012	28,523	19,699	8,824	-	-	-
Three-year average		**18,040**	**13,645**	**4,395**	**-**	**-**	**-**

2014 Cost Allocation Model

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Sheet I8 Demand Data Worksheet - RUN 2 after IRRs and Clarification Qs

This is an input sheet for demand allocators.

CP TEST RESULTS	4 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

			1	2	3	7	9
Customer Classes		**Total**	**Residential**	**General Service less than 50 kW**	**General Service 50 to 4,999 kW**	**Street Lighting**	**Unmetered Scattered Load**
CO-INCIDENT PEAK							
1 CP							
Transformation CP	TCP1	39,315	12,701	9,614	16,975	-	25
Bulk Delivery CP	BCP1	39,315	12,701	9,614	16,975	-	25
Total Sytem CP	DCP1	39,315	12,701	9,614	16,975	-	25
4 CP							
Transformation CP	TCP4	147,456	44,057	41,082	62,216	-	102
Bulk Delivery CP	BCP4	147,456	44,057	41,082	62,216	-	102
Total Sytem CP	DCP4	147,456	44,057	41,082	62,216	-	102
12 CP							
Transformation CP	TCP12	365,122	121,933	92,154	149,441	1,273	322
Bulk Delivery CP	BCP12	365,122	121,933	92,154	149,441	1,273	322
Total Sytem CP	DCP12	365,122	121,933	92,154	149,441	1,273	322
NON CO_INCIDENT PEAK							
1 NCP							
Classification NCP from Load Data Provider	DNCP1	44,851	14,597	12,111	17,822	291	29
Primary NCP	PNCP1	44,851	14,597	12,111	17,822	291	29
Line Transformer NCP	LTNCP1	43,546	14,597	12,111	16,517	291	29
Secondary NCP	SNCP1	23,134	13,575	6,564	2,673	291	29
4 NCP							
Classification NCP from Load Data Provider	DNCP4	167,431	54,862	45,135	66,162	1,155	118
Primary NCP	PNCP4	167,431	54,862	45,135	66,162	1,155	118

Line Transformer NCP	LTNCP4	162,586	54,862	45,135	61,317	1,155	118
Secondary NCP	SNCP4	86,682	51,022	24,463	9,924	1,155	118
12 NCP							
Classification NCP from Load Data Provider	DNCP12	413,331	148,169	101,069	160,300	3,441	353
Primary NCP	PNCP12	413,331	148,169	101,069	160,300	3,441	353
Line Transformer NCP	LTNCP12	401,593	148,169	101,069	148,562	3,441	353
Secondary NCP	SNCP12	220,415	137,797	54,780	24,045	3,441	353

EB-2013-0155

Sheet O1 Revenue to Cost Summary Worksheet - RUN 2 after IRRs and Clarification Qs

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

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 General Service less than 50 kW	3 General Service 50 to 4,999 kW	7 Street Lighting	9 Unmetered Scattered Load
crev	Distribution Revenue at Existing Rates	$4,844,096	$2,422,493	$1,242,401	$973,998	$187,134	$18,069
mi	Miscellaneous Revenue (mi)	$260,781	$167,257	$45,067	$27,606	$20,462	$390
		Miscellaneous Revenue Input equals Output					
	Total Revenue at Existing Rates	$5,104,877	$2,589,750	$1,287,468	$1,001,605	$207,596	$18,459
	Factor required to recover deficiency (1 + D)	0.9470					
	Distribution Revenue at Status Quo Rates	$4,587,163	$2,294,003	$1,176,504	$922,337	$177,208	$17,111
	Miscellaneous Revenue (mi)	$260,781	$167,257	$45,067	$27,606	$20,462	$390
	Total Revenue at Status Quo Rates	$4,847,944	$2,461,260	$1,221,570	$949,943	$197,670	$17,501
	Expenses						
di	Distribution Costs (di)	$718,754	$401,654	$130,985	$116,204	$68,966	$945
cu	Customer Related Costs (cu)	$763,683	$588,283	$117,573	$33,507	$23,229	$1,091
ad	General and Administration (ad)	$761,422	$501,372	$129,222	$81,462	$48,331	$1,034
dep	Depreciation and Amortization (dep)	$911,109	$510,756	$177,628	$153,059	$68,671	$996
INPUT	PILs (INPUT)	$35,595	$18,919	$7,097	$6,750	$2,788	$42
INT	Interest	$723,666	$384,626	$144,289	$137,229	$56,673	$850
	Total Expenses	$3,914,229	$2,405,610	$706,794	$528,210	$268,658	$4,958
	Direct Allocation	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$933,714	$496,266	$186,169	$177,060	$73,122	$1,097
	Revenue Requirement (includes NI)	$4,847,944	$2,901,875	$892,963	$705,270	$341,780	$6,056
		Revenue Requirement Input equals Output					
	Rate Base Calculation						
	Net Assets						
dp	Distribution Plant - Gross	$46,723,687	$25,953,111	$8,821,389	$7,678,530	$4,211,666	$58,991
gp	General Plant - Gross	$6,077,041	$3,368,402	$1,159,094	$1,052,844	$489,580	$7,121
accum dep	Accumulated Depreciation	($23,289,742)	($12,788,128)	($4,418,972)	($3,751,514)	($2,299,643)	($31,484)
co	Capital Contribution	($7,458,609)	($4,769,747)	($1,180,867)	($828,901)	($670,376)	($8,717)
	Total Net Plant	$22,052,377	$11,763,638	$4,380,643	$4,150,959	$1,731,227	$25,911
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$19,960,556	$7,233,520	$4,014,220	$8,538,495	$148,722	$25,599
	OM&A Expenses	$2,243,859	$1,491,309	$377,780	$231,173	$140,526	$3,070
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0
	Subtotal	*$22,204,414*	*$8,724,829*	*$4,392,000*	*$8,769,668*	*$289,248*	*$28,670*
	Working Capital	$2,886,574	$1,134,228	$570,960	$1,140,057	$37,602	$3,727
	Total Rate Base	$24,938,951	$12,897,865	$4,951,603	$5,291,016	$1,768,829	$29,638
		Rate Base Input equals Output					
	Equity Component of Rate Base	$9,975,580	$5,159,146	$1,980,641	$2,116,406	$707,532	$11,855
	Net Income on Allocated Assets	$933,714	$55,650	$514,776	$421,734	($70,988)	$12,542
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0
	Net Income	$933,714	$55,650	$514,776	$421,734	($70,988)	$12,542
	RATIOS ANALYSIS						
	REVENUE TO EXPENSES STATUS QUO%	100.00%	84.82%	136.80%	134.69%	57.84%	288.99%
	EXISTING REVENUE MINUS ALLOCATED COSTS	$256,933	($312,126)	$394,505	$296,335	($134,184)	$12,403
		Deficiency Input equals Output					
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	$0	($440,616)	$328,607	$244,674	($144,110)	$11,445
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.36%	1.08%	25.99%	19.93%	-10.03%	105.80%

2014 Cost Allocation Model

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Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - RUN 2 after IRRs and Clarificatio

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	7	9
	Residential	General Service less than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Unmetered Scattered Load
Customer Unit Cost per month - Avoided Cost	$8.37	$9.51	$29.35	$0.92	$3.83
Customer Unit Cost per month - Directly Related	$11.98	$13.52	$42.85	$1.42	$5.87
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$26.21	$25.10	$51.43	$13.99	$17.33
Existing Approved Fixed Charge	$18.31	$45.97	$328.41	$4.98	$54.31

Attachment 3

Updated Bill Impacts

For Response to Energy Probe Question 7

File Number:	EB-2013-0155
Exhibit:	8
Tab:	1
Schedule:	8
Page:	1
Date:	February 14, 2014

Appendix 2-W
Bill Impacts

Customer Class: **Residential**

TOU / non-TOU: TOU

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

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 18.3100	1	$ 18.31	$ 18.5000	1	$ 18.50	$ 0.19	1.04%
Smart Meter Disposition	Monthly	$ 1.1900	1	$ 1.19	$ -	1	$ -	-$ 1.19	-100.00%
SMIRR Recovery	Monthly	$ 2.8400	1	$ 2.84	$ -	1	$ -	-$ 2.84	-100.00%
Stranded Meter recovery	Monthly	$ -	1	$ -	$ 0.9000	1	$ 0.90	$ 0.90	
Distribution Volumetric Rate	per kWh	$ 0.0129	800	$ 10.32	$ 0.0130	800	$ 10.40	$ 0.08	0.78%
Sub-Total A (excluding pass through)				$ 32.66			$ 29.80	**-$ 2.86**	**-8.76%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0006	800	-$ 0.48	-$ 0.0005	800	-$ 0.40	$ 0.08	-16.67%
DVA 1562 disposition	per kWh	-$ 0.0011	800	-$ 0.88	$ -	800	$ -	$ 0.88	-100.00%
Tax change rider	per kWh	-$ 0.0006	800	-$ 0.48	$ -	800	$ -	$ 0.48	-100.00%
DVA 1576 Disposition Rider	per kWh	$ -	800	$ -	-$ 0.0010	800	-$ 0.77	-$ 0.77	
Line Losses on Cost of Power		$ 0.0889	37.04	$ 3.29	$ 0.0889	30.32	$ 2.70	-$ 0.60	-18.14%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 34.90**			**$ 32.11**	**-$ 2.79**	**-8.00%**
RTSR - Network	per kWh	$ 0.0070	837	$ 5.86	$ 0.0072	830	$ 5.98	$ 0.12	2.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0012	837	$ 1.00	$ 0.0013	830	$ 1.08	$ 0.07	7.46%
Sub-Total C - Delivery (including Sub-Total B)				**$ 41.77**			**$ 39.17**	**-$ 2.60**	**-6.22%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	837	$ 3.68	$ 0.0044	830	$ 3.65	-$ 0.03	-0.80%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	837	$ 1.00	$ 0.0012	830	$ 1.00	-$ 0.01	-0.80%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0720	512	$ 36.86	$ 0.0720	512	$ 36.86	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1090	144	$ 15.70	$ 0.1090	144	$ 15.70	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1290	144	$ 18.58	$ 0.1290	144	$ 18.58	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0830	800	$ 66.40	$ 0.0830	800	$ 66.40	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0970	0	$ -	$ 0.0970	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 123.44**			**$ 120.81**	**-$ 2.63**	**-2.13%**
HST		13%		$ 16.05	13%		$ 15.70	-$ 0.34	-2.13%
Total Bill (including HST)				$ 139.49			$ 136.51	-$ 2.98	-2.13%
Ontario Clean Energy Benefit [1]				-$ 13.95			-$ 13.65	$ 0.30	-2.15%
Total Bill on TOU (including OCEB)				**$ 125.54**			**$ 122.86**	**-$ 2.68**	**-2.13%**
Total Bill on RPP (before Taxes)				**$ 118.70**			**$ 116.07**	**-$ 2.63**	**-2.22%**
HST		13%		$ 15.43	13%		$ 15.09	-$ 0.34	-2.22%
Total Bill (including HST)				$ 134.14			$ 131.16	-$ 2.98	-2.22%
Ontario Clean Energy Benefit [1]				-$ 13.41			-$ 13.12	$ 0.29	-2.16%
Total Bill on RPP (including OCEB)				**$ 120.73**			**$ 118.04**	**-$ 2.69**	**-2.23%**
Loss Factor (%)		4.63%			3.79%				

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

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Customer Class: **General Service Less than 50kW**

TOU / non-TOU: TOU

Consumption 2,000 **kWh** ○ May 1 - October 31

	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	$ 45.9700	1	$ 45.97	$ 37.9800	1	$ 37.98	-$ 7.99	-17.38%
Smart Meter Disposition	Monthly	$ 3.1500	1	$ 3.15	$ -	1	$ -	-$ 3.15	-100.00%
SMIRR Recovery	Monthly	$ 4.8500	1	$ 4.85	$ -	1	$ -	-$ 4.85	-100.00%
Stranded Meter recovery	Monthly	$ -	1	$ -	$ 1.0600	1	$ 1.06	$ 1.06	
Distribution Volumetric Rate	per kWh	$ 0.0138	2000	$ 27.60	$ 0.0114	2000	$ 22.80	-$ 4.80	-17.39%
Sub-Total A (excluding pass through)				$ 81.57			$ 61.84	**-$ 19.73**	**-24.19%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0006	2000	-$ 1.20	-$ 0.0020	2000	-$ 4.00	-$ 2.80	233.33%
DVA 1562 disposition	per kWh	-$ 0.0011	2000	-$ 2.20	$ -	2000	$ -	$ 2.20	-100.00%
Tax change rider	per kWh	-$ 0.0005	2000	-$ 1.00	$ -	2000	$ -	$ 1.00	-100.00%
DVA 1576 Disposition Rider	per kWh	$ -	2000	$ -	-$ 0.0010	2000	-$ 2.00	-$ 2.00	
Line Losses on Cost of Power		$ 0.0889	92.60	$ 8.23	$ 0.0889	75.80	$ 6.74	-$ 1.49	-18.14%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 86.19**			**$ 63.37**	**-$ 22.82**	**-26.48%**
RTSR - Network	per kWh	$ 0.0064	2093	$ 13.39	$ 0.0066	2076	$ 13.70	$ 0.31	2.30%
RTSR - Line and Transformation Connection	per kWh	$ 0.0012	2093	$ 2.51	$ 0.0013	2076	$ 2.70	$ 0.19	7.46%
Sub-Total C - Delivery (including Sub-Total B)				**$ 102.10**			**$ 79.77**	**-$ 22.33**	**-21.87%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2093	$ 9.21	$ 0.0044	2076	$ 9.13	-$ 0.07	-0.80%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	2093	$ 2.51	$ 0.0012	2076	$ 2.49	-$ 0.02	-0.80%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0720	1280	$ 92.16	$ 0.0720	1280	$ 92.16	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1090	360	$ 39.24	$ 0.1090	360	$ 39.24	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1290	360	$ 46.44	$ 0.1290	360	$ 46.44	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0830	750	$ 62.25	$ 0.0830	750	$ 62.25	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0970	1250	$ 121.25	$ 0.0970	1250	$ 121.25	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 305.91**			**$ 283.48**	**-$ 22.42**	**-7.33%**
HST		13%		$ 39.77	13%		$ 36.85	-$ 2.91	-7.33%
Total Bill (including HST)				$ 345.67			$ 320.34	-$ 25.34	-7.33%
Ontario Clean Energy Benefit [1]				-$ 34.57			-$ 32.03	$ 2.54	-7.35%
Total Bill on TOU (including OCEB)				**$ 311.10**			**$ 288.31**	**-$ 22.80**	**-7.33%**
Total Bill on RPP (before Taxes)				**$ 311.57**			**$ 289.14**	**-$ 22.42**	**-7.20%**
HST		13%		$ 40.50	13%		$ 37.59	-$ 2.91	-7.20%
Total Bill (including HST)				$ 352.07			$ 326.73	-$ 25.34	-7.20%
Ontario Clean Energy Benefit [1]				-$ 35.21			-$ 32.67	$ 2.54	-7.21%
Total Bill on RPP (including OCEB)				**$ 316.86**			**$ 294.06**	**-$ 22.80**	**-7.19%**

	Current	Proposed
Loss Factor (%)	4.63%	3.79%

Customer Class: **General Service 50 to 4,999 kW**

TOU / non-TOU: non-TOU

	Consumption	**56,000**	**kWh**	May 1 - October 31					
		150	**kW**						
		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 328.4100	1	$ 328.41	$ 276.0500	1	$ 276.05	-$ 52.36	-15.94%
Distribution Volumetric Rate	per kW	$ 2.5664	150	$ 384.96	$ 2.1748	150	$ 326.21	-$ 58.75	-15.26%
Sub-Total A (excluding pass through)				$ 713.37			$ 602.26	**-$ 111.11**	**-15.57%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.1856	150	-$ 27.84	-$ 1.3909	150	-$ 208.63	-$ 180.79	649.38%
DVA Rate Rider Non-RPP	per kW	$ 2.1024	150	$ 315.36	-$ 0.8249				
DVA 1562 disposition	per kW	-$ 0.1744	150	-$ 26.16	$ -	150	$ -	$ 26.16	-100.00%
Tax change rider	per kW	-$ 0.0802	150	-$ 12.03	$ -	150	$ -	$ 12.03	-100.00%
DVA 1576 Disposition Rider	per kW	$ -	150	$ -	-$ 0.3760	150	-$ 56.40	-$ 56.40	
Line Losses on Cost of Power		$ 0.0876	2,592.80	$ 227.13	$ 0.0876	2,122.40	$ 185.92	-$ 41.21	-18.14%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 1,189.83**			**$ 523.15**	**-$ 666.68**	**-56.03%**
RTSR - Network	per kW	$ 2.5928	150	$ 388.92	$ 2.6853	150	$ 402.80	$ 13.87	3.57%
RTSR - Line and Transformation Connection	per kW	$ 0.4315	150	$ 64.73	$ 0.4602	150	$ 69.03	$ 4.31	6.65%
Sub-Total C - Delivery (including Sub-Total B)				**$ 1,643.47**			**$ 994.98**	**-$ 648.50**	**-39.46%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	56000	$ 246.40	$ 0.0044	56000	$ 246.40	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	56000	$ 67.20	$ 0.0012	56000	$ 67.20	$ -	0.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	56000	$ 392.00	$ 0.0070	56000	$ 392.00	$ -	0.00%
Energy - Non RPP	per kWh	$ 0.0876	56000	$ 4,905.60	$ 0.0876	56000	$ 4,905.60	$ -	0.00%
Total Bill (before Taxes)				**$ 7,254.92**			**$ 6,606.43**	**-$ 648.50**	**-8.94%**
HST		13%		$ 943.14	13%		$ 858.84	-$ 84.30	-8.94%
Total Bill (including HST)				$ 8,198.06			$ 7,465.26	-$ 732.80	-8.94%
Total Bill				**$ 8,198.06**			**$ 7,465.26**	**-$ 732.80**	**-8.94%**

Loss Factor (%)	4.63%	3.79%

Customer Class: **Street Lighting**

TOU / non-TOU: non-TOU

Consumption **50** **kWh** May 1 - October 31
0.14 **kW**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 4.9800	1	$ 4.98	$ 7.6500	1	$ 7.65	$ 2.67	53.61%
Distribution Volumetric Rate	per kW	$ 19.4795	0.14	$ 2.73	$ 29.9280	0.14	$ 4.19	$ 1.46	53.64%
Sub-Total A (excluding pass through)				$ 7.71			$ 11.84	**$ 4.13**	**53.62%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.1611	0.14	-$ 0.02	-$ 1.1086	0.14	-$ 0.16	-$ 0.13	588.16%
DVA Rate Rider Non-RPP	per kW	$ 1.8803	0.14	$ 0.26	-$ 0.7620	0.14	-$ 0.11	-$ 0.37	-140.53%
DVA 1562 disposition	per kW	-$ 2.4982	0.14	-$ 0.35	$ -	0.14	$ -	$ 0.35	-100.00%
Tax change rider	per kW	-$ 0.9793	0.14	-$ 0.14	$ -	0.14	$ -	$ 0.14	-100.00%
DVA 1576 Disposition Rider	per kW	$ -	0.14	$ -	-$ 0.3473	0.14	-$ 0.05	-$ 0.05	
Line Losses on Cost of Power		$ 0.0876	0.01	$ 0.00	$ 0.0876	0.01	$ 0.00	-$ 0.00	-18.14%
Smart Meter Entity Charge			1	$ -		1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 7.46**			**$ 11.53**	**$ 4.07**	**54.52%**
RTSR - Network	per kW	$ 1.9552	0.14	$ 0.27	$ 2.0249	0.14	$ 0.28	$ 0.01	3.56%
RTSR - Line and Transformation Connection	per kW	$ 0.3336	0.14	$ 0.05	$ 0.3558	0.14	$ 0.05	$ 0.00	6.65%
Sub-Total C - Delivery (including Sub-Total B)				**$ 7.78**			**$ 11.86**	**$ 4.08**	**52.44%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	50	$ 0.22	$ 0.0044	50	$ 0.22	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	50	$ 0.06	$ 0.0012	50	$ 0.06	$ -	0.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	50	$ 0.35	$ 0.0070	50	$ 0.35	$ -	0.00%
Energy - Non RPP	per kWh	$ 0.0876	50	$ 4.38	$ 0.0876	50	$ 4.38	$ -	0.00%
Total Bill (before Taxes)				**$ 13.04**			**$ 17.12**	**$ 4.08**	**31.29%**
HST		13%		$ 1.70	13%		$ 2.23	$ 0.53	31.29%
Total Bill (including HST)				$ 14.74			$ 19.35	$ 4.61	31.29%
Total Bill				**$ 14.74**			**$ 19.35**	**$ 4.61**	**31.29%**

Loss Factor (%)	4.63%	3.79%

Customer Class: **Unmetered Scattered Load**

TOU / non-TOU: TOU

Consumption 900 **kWh** ○ May 1 - October 31

	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	$ 54.3100	1	$ 54.31	$ 20.6700	1	$ 20.67	-$ 33.64	-61.94%
Distribution Volumetric Rate	per kWh	$ 0.0163	900	$ 14.67	$ 0.0062	900	$ 5.58	-$ 9.09	-61.94%
Sub-Total A (excluding pass through)				$ 68.98			$ 26.25	**-$ 42.73**	**-61.94%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0008	900	-$ 0.72	-$ 0.0006	900	-$ 0.54	$ 0.18	-25.00%
DVA 1562 disposition	per kWh	-$ 0.0037	900	-$ 3.33	$ -	900	$ -	$ 3.33	-100.00%
Tax change rider	per kWh	-$ 0.0014	900	-$ 1.26	$ -	900	$ -	$ 1.26	-100.00%
DVA 1576 Disposition Rider	per kWh	$ -	900	$ -	-$ 0.0010	900	-$ 0.87	-$ 0.87	
Line Losses on Cost of Power		$ 0.0889	41.67	$ 3.71	$ 0.0889	34.11	$ 3.03	-$ 0.67	-18.14%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 67.38**			**$ 27.88**	**-$ 39.50**	**-58.63%**
RTSR - Network	per kWh	$ 0.0064	942	$ 6.03	$ 0.0066	934	$ 6.17	$ 0.14	2.30%
RTSR - Line and Transformation Connection	per kWh	$ 0.0012	942	$ 1.13	$ 0.0013	934	$ 1.21	$ 0.08	7.46%
Sub-Total C - Delivery (including Sub-Total B)				**$ 74.53**			**$ 35.26**	**-$ 39.28**	**-52.70%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	942	$ 4.14	$ 0.0044	934	$ 4.11	-$ 0.03	-0.80%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	942	$ 1.13	$ 0.0012	934	$ 1.12	-$ 0.01	-0.80%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	900	$ 6.30	$ 0.0070	900	$ 6.30	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0720	576	$ 41.47	$ 0.0720	576	$ 41.47	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1090	162	$ 17.66	$ 0.1090	162	$ 17.66	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1290	162	$ 20.90	$ 0.1290	162	$ 20.90	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0830	750	$ 62.25	$ 0.0830	750	$ 62.25	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0970	150	$ 14.55	$ 0.0970	150	$ 14.55	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 166.38**			**$ 127.06**	**-$ 39.32**	**-23.63%**
HST		13%		$ 21.63	13%		$ 16.52	-$ 5.11	-23.63%
Total Bill (including HST)				$ 188.01			$ 143.58	-$ 44.43	-23.63%
Ontario Clean Energy Benefit [1]				-$ 18.80			-$ 14.36	$ 4.44	-23.62%
Total Bill on TOU (including OCEB)				**$ 169.21**			**$ 129.22**	**-$ 39.99**	**-23.63%**
Total Bill on RPP (before Taxes)				**$ 163.16**			**$ 123.84**	**-$ 39.32**	**-24.10%**
HST		13%		$ 21.21	13%		$ 16.10	-$ 5.11	-24.10%
Total Bill (including HST)				$ 184.37			$ 139.94	-$ 44.43	-24.10%
Ontario Clean Energy Benefit [1]				-$ 18.44			-$ 13.99	$ 4.45	-24.13%
Total Bill on RPP (including OCEB)				**$ 165.93**			**$ 125.95**	**-$ 39.98**	**-24.10%**

Loss Factor (%)	4.63%	3.79%

Attachment 4

Updated RRWF

For Response to Energy Probe Question 8

Revenue Requirement Workform

Data Input (1)

Row		Item	Initial Application	(2)	Adjustments	Supplementary Interrogatory Responses	(6)	stm	Per Board Decision	
15	1	**Rate Base**								
16		Gross Fixed Assets (average)	$45,176,948	**See Note 10**	$165,171.23	$ 45,342,119			$45,342,119	
17		Accumulated Depreciation (average)	($22,963,012)	**(5)**	($326,730.12)	($23,289,742)			($23,289,742)	
18		Allowance for Working Capital:								
19		Controllable Expenses	$2,259,303	**See Note 11**	($15,445)	$ 2,243,859			$2,243,859	
20		Cost of Power	$19,138,712	**See Note 12**	$821,843	$ 19,960,556			$19,960,556	
21		Working Capital Rate (%)	13.00%	**(9)**		13.00%	**(9)**		13.00%	**(9)**
23	2	**Utility Income**								
24		Operating Revenues:								
25		Distribution Revenue at Current Rates	$4,844,096		$0	$4,844,096				
26		Distribution Revenue at Proposed Rates	$4,545,964		$41,198	$4,587,163				
27		Other Revenue:								
28		Specific Service Charges	$58,300	**See Note 13**	$18,030	$76,330				
29		Late Payment Charges	$38,000		$0	$38,000				
30		Other Distribution Revenue	$112,751		$0	$112,751				
31		Other Income and Deductions	$33,700		$0	$33,700				
33		Total Revenue Offsets	$242,751	**(7)**						
35		Operating Expenses:								
36		OM+A Expenses	$2,230,707	**See Note 14**	($15,444.81)	$ 2,215,262			$2,215,262	
37		Depreciation/Amortization	$929,588	**See Note 15**	($18,478.32)	$ 911,109			$911,109	
38		Property taxes	$28,596		$ -	$ 28,596			$28,596	
40		Other expenses								
42	3	**Taxes/PILs**								
43		Taxable Income:								
44		Adjustments required to arrive at taxable income	($642,662)	**(3)**		($662,245)				
45		Utility Income Taxes and Rates:								
46		Income taxes (not grossed up)	$27,553	**See Note 16**		$30,078				
47		Income taxes (grossed up)	$32,607			$35,595				
49		Federal tax (%)	11.00%			11.00%				
50		Provincial tax (%)	4.50%			4.50%				
51		Income Tax Credits	($12,000)			($12,000)				
53	4	**Capitalization/Cost of Capital**								
54		Capital Structure:								
55		Long-term debt Capitalization Ratio (%)	56.0%			56.0%				
56		Short-term debt Capitalization Ratio (%)	4.0%	**(8)**		4.0%	**(8)**			**(8)**
57		Common Equity Capitalization Ratio (%)	40.0%			40.0%				
58		Prefered Shares Capitalization Ratio (%)	0.0%			0.0%				
59			100.0%			100.0%				
61		Cost of Capital								
62		Long-term debt Cost Rate (%)	4.63%			5.03%				
63		Short-term debt Cost Rate (%)	2.07%			2.11%				
64		Common Equity Cost Rate (%)	8.98%			9.36%				
65		Prefered Shares Cost Rate (%)	0.00%			0.00%				

Notes:

General	Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.
(1)	All inputs are in dollars ($) except where inputs are individually identified as percentages (%)
(2)	Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I
(3)	Net of addbacks and deductions to arrive at taxable income.
(4)	Average of Gross Fixed Assets at beginning and end of the Test Year
(5)	Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.
(6)	Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.
(7)	Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement
(8)	4.0% unless an Applicant has proposed or been approved for another amount.
(9)	Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.

NOTL Notes

(10) The actual (unaudited) net of additions and disposals in 2013 is more than in the initial application. The net of additions and disposals in 2014 is unchanged. Accumulated depreciation changed based on 2013 actuals (unaudited) and re-allocation ($30,000) from trucks to software in 2014.
(11) Reduction referenced in 4.2-VECC-15
(12) To reflect the OEB's Regulated Price Plan Price Report dated October 17, 2013
(13) Increase referenced in 7.1-VECC-22
(14) See Note 11
(15) Effect of actual (unaudited) 2013 capital additions and disposals and re-allocation ($30,000) from trucks to software in 2014
(16) Effect of CCA class change for computer hardware is one of the causes of the adjustment

Revenue Requirement Workform

Version 4.00

Utility Name	Niagara-on-the-Lake Hydro Inc.
Service Territory	*Niagara-on-the-Lake*
Assigned EB Number	EB-2013-0155
Name and Title	Philip Wormwell, Directoir of Corporate Services
Phone Number	905-468-4235- Ext 380
Email Address	pwormwell@notlhydro.com

Revenue Requirement Workform

1. Info
2. Table of Contents
3. Data_Input_Sheet
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5. Utility Income
6. Taxes_PILs
7. Cost_of_Capital
8. Rev_Def_Suff
9. Rev_Reqt

Notes:

(1) Pale green cells represent inputs

(2) Pale green boxes at the bottom of each page are for additional notes

(3) Pale yellow cells represent drop-down lists

(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel***

Revenue Requirement Workform

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Supplementary Interrogatory	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$45,176,948	$165,171	$45,342,119	$ -	$45,342,119
2	Accumulated Depreciation (average)	(3)	($22,963,012)	($326,730)	($23,289,742)	$ -	($23,289,742)
3	Net Fixed Assets (average)	(3)	$22,213,936	($161,559)	$22,052,377	$ -	$22,052,377
4	Allowance for Working Capital	(1)	$2,781,742	$104,832	$2,886,574	$ -	$2,886,574
5	**Total Rate Base**		$24,995,678	($56,727)	$24,938,951	$ -	$24,938,951

(1) ### Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments	Supplementary Interrogatory	Adjustments	Per Board Decision
6	Controllable Expenses		$2,259,303	($15,445)	$2,243,859	$ -	$2,243,859
7	Cost of Power		$19,138,712	$821,843	$19,960,556	$ -	$19,960,556
8	Working Capital Base		$21,398,016	$806,399	$22,204,414	$ -	$22,204,414
9	Working Capital Rate %	(2)	13.00%	0.00%	13.00%	0.00%	13.00%
10	Working Capital Allowance		$2,781,742	$104,832	$2,886,574	$ -	$2,886,574

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2014 cost of service applications is 13%.

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

Revenue Requirement Workform

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Supplementary Interrogatory	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$4,545,964	$41,198	$4,587,163	$ -	$4,587,163
2	Other Revenue	(1)	$242,751	$18,030	$260,781	$ -	$260,781
3	Total Operating Revenues		$4,788,716	$59,228	$4,847,944	$ -	$4,847,944
	Operating Expenses:						
4	OM+A Expenses		$2,230,707	($15,445)	$2,215,262	$ -	$2,215,262
5	Depreciation/Amortization		$929,588	($18,478)	$911,109	$ -	$911,109
6	Property taxes		$28,596	$ -	$28,596	$ -	$28,596
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$3,188,891	($33,923)	$3,154,968	$ -	$3,154,968
10	Deemed Interest Expense		$669,372	$54,294	$723,666	($55,813)	$667,853
11	Total Expenses (lines 9 to 10)		$3,858,263	$20,371	$3,878,635	($55,813)	$3,822,821
12	**Utility income before income taxes**		$930,452	$38,857	$969,309	$55,813	$1,025,123
13	Income taxes (grossed-up)		$32,607	$2,987	$35,595	$ -	$35,595
14	**Utility net income**		$897,845	$35,870	$933,714	$55,813	$989,528

Notes

Other Revenues / Revenue Offsets

Note	Particulars	Initial Application	Adjustments	Supplementary Interrogatory	Adjustments	Per Board Decision
(1)	Specific Service Charges	$58,300	$18,030	$76,330		$76,330
	Late Payment Charges	$38,000	$ -	$38,000		$38,000
	Other Distribution Revenue	$112,751	$ -	$112,751		$112,751
	Other Income and Deductions	$33,700	$ -	$33,700		$33,700
	Total Revenue Offsets	$242,751	$18,030	$260,781	$ -	$260,781

Revenue Requirement Workform

Taxes/PILs

Line No.	Particulars	Application	Supplementary Interrogatory	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$897,845	$933,714	$895,807
2	Adjustments required to arrive at taxable utility income	($642,662)	($662,245)	($642,662)
3	Taxable income	$255,183	$271,469	$253,145
	Calculation of Utility income Taxes			
4	Income taxes	$27,553	$30,078	$30,078
6	Total taxes	$27,553	$30,078	$30,078
7	Gross-up of Income Taxes	$5,054	$5,517	$5,517
8	Grossed-up Income Taxes	$32,607	$35,595	$35,595
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$32,607	$35,595	$35,595
10	Other tax Credits	($12,000)	($12,000)	($12,000)
	Tax Rates			
11	Federal tax (%)	11.00%	11.00%	11.00%
12	Provincial tax (%)	4.50%	4.50%	4.50%
13	Total tax rate (%)	15.50%	15.50%	15.50%

Notes

Revenue Requirement Workform

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$13,997,580	4.63%	$648,676
2	Short-term Debt	4.00%	$999,827	2.07%	$20,696
3	**Total Debt**	60.00%	$14,997,407	4.46%	$669,372
	Equity				
4	Common Equity	40.00%	$9,998,271	8.98%	$897,845
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$9,998,271	8.98%	$897,845
7	**Total**	100.00%	$24,995,678	6.27%	$1,567,217
		Supplementary Interrogatory Responses			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$13,965,813	5.03%	$702,618
2	Short-term Debt	4.00%	$997,558	2.11%	$21,048
3	**Total Debt**	60.00%	$14,963,371	4.84%	$723,666
	Equity				
4	Common Equity	40.00%	$9,975,580	9.36%	$933,714
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$9,975,580	9.36%	$933,714
7	**Total**	100.00%	$24,938,951	6.65%	$1,657,381
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$13,965,813	4.63%	$647,203
9	Short-term Debt	4.00%	$997,558	2.07%	$20,649
10	**Total Debt**	60.00%	$14,963,371	4.46%	$667,853
	Equity				
11	Common Equity	40.00%	$9,975,580	8.98%	$895,807
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$9,975,580	8.98%	$895,807
14	**Total**	100.00%	$24,938,951	6.27%	$1,563,660

Notes

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Revenue Requirement Workform

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Supplementary Interrogatory Responses: At Current Approved Rates	Supplementary Interrogatory Responses: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		($298,131)		($256,933)		($357,607)
2	Distribution Revenue	$4,844,096	$4,844,096	$4,844,096	$4,844,096	$4,844,096	$4,944,770
3	Other Operating Revenue Offsets - net	$242,751	$242,751	$260,781	$260,781	$260,781	$260,781
4	**Total Revenue**	$5,086,847	$4,788,716	$5,104,877	$4,847,944	$5,104,877	$4,847,944
5	Operating Expenses	$3,188,891	$3,188,891	$3,154,968	$3,154,968	$3,154,968	$3,154,968
6	Deemed Interest Expense	$669,372	$669,372	$723,666	$723,666	$667,853	$667,853
8	**Total Cost and Expenses**	$3,858,263	$3,858,263	$3,878,635	$3,878,635	$3,822,821	$3,822,821
9	**Utility Income Before Income Taxes**	$1,228,583	$930,452	$1,226,242	$969,309	$1,282,056	$1,025,123
10	Tax Adjustments to Accounting Income per 2013 PILs model	($642,662)	($642,662)	($662,245)	($662,245)	($662,245)	($662,245)
11	**Taxable Income**	$585,921	$287,790	$563,997	$307,064	$619,810	$362,877
12	Income Tax Rate	15.50%	15.50%	15.50%	15.50%	15.50%	15.50%
13	**Income Tax on Taxable Income**	$90,818	$44,607	$87,420	$47,595	$96,071	$56,246
14	**Income Tax Credits**	($12,000)	($12,000)	($12,000)	($12,000)	($12,000)	($12,000)
15	**Utility Net Income**	$1,149,766	$897,845	$1,150,823	$933,714	$1,197,985	$989,528
16	**Utility Rate Base**	$24,995,678	$24,995,678	$24,938,951	$24,938,951	$24,938,951	$24,938,951
17	Deemed Equity Portion of Rate Base	$9,998,271	$9,998,271	$9,975,580	$9,975,580	$9,975,580	$9,975,580
18	Income/(Equity Portion of Rate Base)	11.50%	8.98%	11.54%	9.36%	12.01%	9.92%
19	Target Return - Equity on Rate Base	8.98%	8.98%	9.36%	9.36%	8.98%	8.98%
20	Deficiency/Sufficiency in Return on Equity	2.52%	0.00%	2.18%	0.00%	3.03%	0.94%
21	Indicated Rate of Return	7.28%	6.27%	7.52%	6.65%	7.48%	6.65%
22	Requested Rate of Return on Rate Base	6.27%	6.27%	6.65%	6.65%	6.27%	6.27%
23	Deficiency/Sufficiency in Rate of Return	1.01%	0.00%	0.87%	0.00%	1.21%	0.38%
24	Target Return on Equity	$897,845	$897,845	$933,714	$933,714	$895,807	$895,807
25	Revenue Deficiency/(Sufficiency)	($251,921)	($0)	($217,108)	($0)	($302,178)	$93,721
26	**Gross Revenue Deficiency/(Sufficiency)**	($298,131) **(1)**		($256,933) **(1)**		($357,607) **(1)**	

Notes:

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

Revenue Requirement Workform

Revenue Requirement

Line No.	Particulars	Application		Supplementary Interrogatory Responses		Per Board Decision	
1	OM&A Expenses	$2,230,707		$2,215,262		$2,215,262	
2	Amortization/Depreciation	$929,588		$911,109		$911,109	
3	Property Taxes	$28,596		$28,596		$28,596	
5	Income Taxes (Grossed up)	$32,607		$35,595		$35,595	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$669,372		$723,666		$667,853	
	Return on Deemed Equity	$897,845		$933,714		$895,807	
8	**Service Revenue Requirement (before Revenues)**	$4,788,716		$4,847,944		$4,754,223	
9	Revenue Offsets	$242,751		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$4,545,964		$4,847,944		$4,754,223	
11	Distribution revenue	$4,545,964		$4,587,163		$4,587,163	
12	Other revenue	$242,751		$260,781		$260,781	
13	**Total revenue**	$4,788,716		$4,847,944		$4,847,944	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($0)	**(1)**	($0)	**(1)**	$93,721	**(1)**

Notes

(1) Line 11 - Line 8

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Appendix 3

Revenue Requirement Work Form

based on Settlement Proposal

Topic	Change Reference	RRWF Data Input reference
Account 4235 - Specific Service Charges	7.1-VECC-22	See RRWF 3. Data Input Sheet, Note 13
Account 4360 - Loss on Disposition	Settlement Issue 7.6	See RRWF 3. Data Input Sheet, Note 13
Account 4086 – SSS Admin		
OM&A	4.2-VECC-15 and Settlement Issue 7.1	See RRWF 3. Data Input Sheet, Note 14
WCA Rate	Settlement Issue 7.1	See RRWF 3. Data Input Sheet, Note 9
1576 update	Settlement Issue 9.1	n/a
Capital Parameters update	7.5-Energy Probe-31and Settlement Issue 7.5	See RRWF 3. Data Input Sheet, Section 4.
Truck disposals update	7.1-Energy Probe-22	See RRWF 3. Data Input Sheet, Note 10
Capital Contributions update	7.1-Energy Probe-20	-
FA Continuity update	7.1-Energy Probe-20	See RRWF 3. Data Input Sheet, Note 10 and Note 15
Cost of Power update	7.1-Energy Probe-24 and Settlement Issue 7.1	See RRWF 3. Data Input Sheet, Note 12
RTSR update	8.5-VECC-38	n/a

Revenue Requirement Workform

Version 4.00

Utility Name	Niagara-on-the-Lake Hydro Inc.
Service Territory	*Niagara-on-the-Lake*
Assigned EB Number	EB-2013-0155
Name and Title	Philip Wormwell, Directoir of Corporate Services
Phone Number	905-468-4235- Ext 380
Email Address	pwormwell@notlhydro.com

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

Revenue Requirement Workform

1. Info

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4. Rate_Base

5. Utility Income

6. Taxes_PILs

7. Cost_of_Capital

8. Rev_Def_Suff

9. Rev_Reqt

Notes:

(1)	Pale green cells represent inputs
(2)	Pale green boxes at the bottom of each page are for additional notes
(3)	Pale yellow cells represent drop-down lists
(4)	***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5)	***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel***

Revenue Requirement Workform

Data Input (1)

		Initial Application	(2)	Adjustments	Settlement Agreement	(6)	Adjustments	Per Board Decision	
1	**Rate Base**								
	Gross Fixed Assets (average)	$45,176,948	**See Note 10**	$165,171.23	$ 45,342,119		$ -	$45,342,119	
	Accumulated Depreciation (average)	($22,963,012)	(5)	($326,730.12)	($23,289,742)		$ -	($23,289,742)	
	Allowance for Working Capital:								
	Controllable Expenses	$2,259,303	**See Note 11**	($113,253.23)	$ 2,146,050		$ -	$2,146,050	
	Cost of Power	$19,138,712	**See Note 12**	$820,515	$ 19,959,228		$ -	$19,959,228	
	Working Capital Rate (%)	13.00%	(9)		11.00%	(9)		11.00%	(9)
2	**Utility Income**								
	Operating Revenues:								
	Distribution Revenue at Current Rates	$4,844,096		$4,640	$4,848,735		$0	$4,848,735	
	Distribution Revenue at Proposed Rates	$4,545,964		($83,965)	$4,462,000		$0	$4,462,000	
	Other Revenue:								
	Specific Service Charges	$58,300	**See Note 13**	$18,030	$76,330		$0	$76,330	
	Late Payment Charges	$38,000		$0	$38,000		$0	$38,000	
	Other Distribution Revenue	$112,751		$96	$112,847		$0	$112,847	
	Other Income and Deductions	$33,700		$22,000	$55,700		$0	$55,700	
	Total Revenue Offsets	$242,751	(7)	$40,126	$282,877		$0	$282,877	
	Operating Expenses:								
	OM+A Expenses	$2,230,707	**See Note 14**	($75,444.81)	$ 2,155,262		$ -	$2,155,262	
	Depreciation/Amortization	$929,588	**See Note 15**	($18,478.32)	$ 911,109		$ -	$911,109	
	Property taxes	$28,596		$ -	$ 28,596		$ -	$28,596	
	Other expenses								
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($642,662)	(3)		($662,245)			($662,245)	
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$27,553	**See Note 16**		$27,437			$27,437	
	Income taxes (grossed up)	$32,607			$32,470			$32,470	
	Federal tax (%)	11.00%			11.00%			11.00%	
	Provincial tax (%)	4.50%			4.50%			4.50%	
	Income Tax Credits	($12,000)			($12,000)			($12,000)	
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%	(8)		4.0%	(8)		4.0%	(8)
	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 (%)	4.63%			4.96%			4.96%	
	Short-term debt Cost Rate (%)	2.07%			2.11%			2.11%	
	Common Equity Cost Rate (%)	8.98%			9.36%			9.36%	
	Prefered Shares Cost Rate (%)	0.00%			0.00%			0.00%	

Notes:

General	Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.
(1)	All inputs are in dollars ($) except where inputs are individually identified as percentages (%)
(2)	Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I
(3)	Net of addbacks and deductions to arrive at taxable income.
(4)	Average of Gross Fixed Assets at beginning and end of the Test Year
(5)	Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.
(6)	Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.
(7)	Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement
(8)	4.0% unless an Applicant has proposed or been approved for another amount.
(9)	Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.

NOTL Notes

	The actual (unaudited) net of additions and disposals in 2013 is more than in the initial application. The net of additions and disposals in 2014 is unchanged.
(10)	Accumulated depreciation changed based on 2013 actuals (unaudited) and re-allocation ($30,000) from trucks to software in 2014.
(11)	Sum of allocated depreciation $37,808 excluded from OM&A for WCA calculation and OM&A reduction $75,445 per Settlement
(12)	See under Issue 7.1 - reflects OEB's RPP Price Report Oct 17, 2013 and adjusted customer #s under Issue 8.1
(13)	Specific Service Charges see 7.1-VECC-22. Other Dist Rev is SSS Admin change due to customer #s adjustment. Other Inc. is change in loss
(14)	OM&A reduction per Settlement
(15)	Effect of actual (unaudited) 2013 capital additions and disposals and re-allocation ($30,000) from trucks to software in 2014
(16)	Effect of CCA class change for computer hardware is one of the causes of the adjustment

Revenue Requirement Workform

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)	$45,176,948	$165,171	$45,342,119	$ -	$45,342,119
2	Accumulated Depreciation (average)	(3)	($22,963,012)	($326,730)	($23,289,742)	$ -	($23,289,742)
3	Net Fixed Assets (average)	(3)	$22,213,936	($161,559)	$22,052,377	$ -	$22,052,377
4	Allowance for Working Capital	(1)	$2,781,742	($350,161)	$2,431,581	$ -	$2,431,581
5	**Total Rate Base**		$24,995,678	($511,720)	$24,483,958	$ -	$24,483,958

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
6	Controllable Expenses		$2,259,303	($113,253)	$2,146,050	$ -	$2,146,050
7	Cost of Power		$19,138,712	$820,515	$19,959,228	$ -	$19,959,228
8	Working Capital Base		$21,398,016	$707,262	$22,105,278	$ -	$22,105,278
9	Working Capital Rate %	(2)	13.00%	-2.00%	11.00%	0.00%	11.00%
10	Working Capital Allowance		$2,781,742	($350,161)	$2,431,581	$ -	$2,431,581

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2014 cost of service applications is 13%.

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

Revenue Requirement Workform

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$4,545,964	($83,965)	$4,462,000	$ -	$4,462,000
2	Other Revenue	(1)	$242,751	$40,126	$282,877	$ -	$282,877
3	Total Operating Revenues		$4,788,716	($43,839)	$4,744,877	$ -	$4,744,877
	Operating Expenses:						
4	OM+A Expenses		$2,230,707	($75,445)	$2,155,262	$ -	$2,155,262
5	Depreciation/Amortization		$929,588	($18,478)	$911,109	$ -	$911,109
6	Property taxes		$28,596	$ -	$28,596	$ -	$28,596
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$3,188,891	($93,923)	$3,094,968	$ -	$3,094,968
10	Deemed Interest Expense		$669,372	$31,387	$700,759	$ -	$700,759
11	Total Expenses (lines 9 to 10)		$3,858,263	($62,536)	$3,795,727	$ -	$3,795,727
12	**Utility income before income taxes**		$930,452	$18,697	$949,150	$ -	$949,150
13	Income taxes (grossed-up)		$32,607	($137)	$32,470	$ -	$32,470
14	**Utility net income**		$897,845	$18,835	$916,679	$ -	$916,679

Notes

Other Revenues / Revenue Offsets

Notes		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
(1)	Specific Service Charges	$58,300	$18,030	$76,330	$ -	$76,330
	Late Payment Charges	$38,000	$ -	$38,000	$ -	$38,000
	Other Distribution Revenue	$112,751	$96	$112,847	$ -	$112,847
	Other Income and Deductions	$33,700	$22,000	$55,700	$ -	$55,700
	Total Revenue Offsets	$242,751	$40,126	$282,877	$ -	$282,877

Revenue Requirement Workform

Taxes/PILs

Line No.	Particulars	Application	Settlement Agreement	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$897,845	$916,679	$916,679
2	Adjustments required to arrive at taxable utility income	($642,662)	($662,245)	($662,245)
3	Taxable income	$255,183	$254,434	$254,434
	Calculation of Utility income Taxes			
4	Income taxes	$27,553	$27,437	$27,437
6	Total taxes	$27,553	$27,437	$27,437
7	Gross-up of Income Taxes	$5,054	$5,033	$5,033
8	Grossed-up Income Taxes	$32,607	$32,470	$32,470
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$32,607	$32,470	$32,470
10	Other tax Credits	($12,000)	($12,000)	($12,000)
	Tax Rates			
11	Federal tax (%)	11.00%	11.00%	11.00%
12	Provincial tax (%)	4.50%	4.50%	4.50%
13	Total tax rate (%)	15.50%	15.50%	15.50%

Notes

Revenue Requirement Workform

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Initial Application				
	Debt				
1	Long-term Debt	56.00%	$13,997,580	4.63%	$648,676
2	Short-term Debt	4.00%	$999,827	2.07%	$20,696
3	**Total Debt**	60.00%	$14,997,407	4.46%	$669,372
	Equity				
4	Common Equity	40.00%	$9,998,271	8.98%	$897,845
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$9,998,271	8.98%	$897,845
7	**Total**	100.00%	$24,995,678	6.27%	$1,567,217
	Settlement Agreement				
	Debt				
1	Long-term Debt	56.00%	$13,711,016	4.96%	$680,095
2	Short-term Debt	4.00%	$979,358	2.11%	$20,664
3	**Total Debt**	60.00%	$14,690,375	4.77%	$700,759
	Equity				
4	Common Equity	40.00%	$9,793,583	9.36%	$916,679
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$9,793,583	9.36%	$916,679
7	**Total**	100.00%	$24,483,958	6.61%	$1,617,439
	Per Board Decision				
	Debt				
8	Long-term Debt	56.00%	$13,711,016	4.96%	$680,095
9	Short-term Debt	4.00%	$979,358	2.11%	$20,664
10	**Total Debt**	60.00%	$14,690,375	4.77%	$700,759
	Equity				
11	Common Equity	40.00%	$9,793,583	9.36%	$916,679
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$9,793,583	9.36%	$916,679
14	**Total**	100.00%	$24,483,958	6.61%	$1,617,439

Notes

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Revenue Requirement Workform

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		($298,131)		($386,736)		($386,736)
2	Distribution Revenue	$4,844,096	$4,844,096	$4,848,735	$4,848,735	$4,848,735	$4,848,735
3	Other Operating Revenue Offsets - net	$242,751	$242,751	$282,877	$282,877	$282,877	$282,877
4	**Total Revenue**	$5,086,847	$4,788,716	$5,131,612	$4,744,877	$5,131,612	$4,744,877
5	Operating Expenses	$3,188,891	$3,188,891	$3,094,968	$3,094,968	$3,094,968	$3,094,968
6	Deemed Interest Expense	$669,372	$669,372	$700,759	$700,759	$700,759	$700,759
8	**Total Cost and Expenses**	$3,858,263	$3,858,263	$3,795,727	$3,795,727	$3,795,727	$3,795,727
9	**Utility Income Before Income Taxes**	$1,228,583	$930,452	$1,335,885	$949,150	$1,335,885	$949,150
10	Tax Adjustments to Accounting Income per 2013 PILs model	($642,662)	($642,662)	($662,245)	($662,245)	($662,245)	($662,245)
11	**Taxable Income**	$585,921	$287,790	$673,640	$286,904	$673,640	$286,904
12	Income Tax Rate	15.50%	15.50%	15.50%	15.50%	15.50%	15.50%
13		$90,818	$44,607	$104,414	$44,470	$104,414	$44,470
	Income Tax on Taxable Income						
14	**Income Tax Credits**	($12,000)	($12,000)	($12,000)	($12,000)	($12,000)	($12,000)
15	**Utility Net Income**	$1,149,766	$897,845	$1,243,471	$916,679	$1,243,471	$916,679
16	**Utility Rate Base**	$24,995,678	$24,995,678	$24,483,958	$24,483,958	$24,483,958	$24,483,958
17	Deemed Equity Portion of Rate Base	$9,998,271	$9,998,271	$9,793,583	$9,793,583	$9,793,583	$9,793,583
18	Income/(Equity Portion of Rate Base)	11.50%	8.98%	12.70%	9.36%	12.70%	9.36%
19	Target Return - Equity on Rate Base	8.98%	8.98%	9.36%	9.36%	9.36%	9.36%
20	Deficiency/Sufficiency in Return on Equity	2.52%	0.00%	3.34%	0.00%	3.34%	0.00%
21	Indicated Rate of Return	7.28%	6.27%	7.94%	6.61%	7.94%	6.61%
22	Requested Rate of Return on Rate Base	6.27%	6.27%	6.61%	6.61%	6.61%	6.61%
23	Deficiency/Sufficiency in Rate of Return	1.01%	0.00%	1.33%	0.00%	1.33%	0.00%
24	Target Return on Equity	$897,845	$897,845	$916,679	$916,679	$916,679	$916,679
25	Revenue Deficiency/(Sufficiency)	($251,921)	($0)	($326,792)	($0)	($326,792)	($0)
26	**Gross Revenue Deficiency/(Sufficiency)**	($298,131) **(1)**		($386,736) **(1)**		($386,736) **(1)**	

Notes:

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

Revenue Requirement Workform

Revenue Requirement

Line No.	Particulars	Application		Settlement Agreement		Per Board Decision	
1	OM&A Expenses	$2,230,707		$2,155,262		$2,155,262	
2	Amortization/Depreciation	$929,588		$911,109		$911,109	
3	Property Taxes	$28,596		$28,596		$28,596	
5	Income Taxes (Grossed up)	$32,607		$32,470		$32,470	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$669,372		$700,759		$700,759	
	Return on Deemed Equity	$897,845		$916,679		$916,679	
8	**Service Revenue Requirement (before Revenues)**	$4,788,716		$4,744,877		$4,744,877	
9	Revenue Offsets	$242,751		$282,877		$282,877	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$4,545,964		$4,462,000		$4,462,000	
11	Distribution revenue	$4,545,964		$4,462,000		$4,462,000	
12	Other revenue	$242,751		$282,877		$282,877	
13	**Total revenue**	$4,788,716		$4,744,877		$4,744,877	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($0)	(1)	($0)	(1)	($0)	(1)

Notes

(1) Line 11 - Line 8

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Appendix 4

Bill Impacts

(Including unsettled Group 2 Rate Riders)

File Number:	EB-2013-0155
Exhibit:	8
Tab:	1
Schedule:	8
Page:	1
Date:	March 6, 2014

Appendix 2-W
Bill Impacts

Customer Class: **Residential**

TOU / non-TOU: TOU

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

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 18.3100	1	$ 18.31	$ 17.9400	1	$ 17.94	-$ 0.37	-2.02%
Smart Meter Disposition	Monthly	$ 1.1900	1	$ 1.19	$ -	1	$ -	-$ 1.19	-100.00%
SMIRR Recovery	Monthly	$ 2.8400	1	$ 2.84	$ -	1	$ -	-$ 2.84	-100.00%
Stranded Meter recovery	Monthly	$ -	1	$ -	$ 0.9000	1	$ 0.90	$ 0.90	
Distribution Volumetric Rate	per kWh	$ 0.0129	800	$ 10.32	$ 0.0126	800	$ 10.08	-$ 0.24	-2.33%
Sub-Total A (excluding pass through)				$ 32.66			$ 28.92	**-$ 3.74**	**-11.45%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0006	800	-$ 0.48	-$ 0.0005	800	-$ 0.40	$ 0.08	-16.67%
DVA 1562 disposition	per kWh	-$ 0.0011	800	-$ 0.88	$ -	800	$ -	$ 0.88	-100.00%
Tax change rider	per kWh	-$ 0.0006	800	-$ 0.48	$ -	800	$ -	$ 0.48	-100.00%
DVA 1576 Disposition Rider	per kWh	$ -	800	$ -	-$ 0.0010	800	-$ 0.77	-$ 0.77	
Line Losses on Cost of Power		$ 0.0889	37.04	$ 3.29	$ 0.0889	30.32	$ 2.70	-$ 0.60	-18.14%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 34.90**			**$ 31.23**	**-$ 3.67**	**-10.52%**
RTSR - Network	per kWh	$ 0.0070	837	$ 5.86	$ 0.0072	830	$ 5.98	$ 0.12	2.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0012	837	$ 1.00	$ 0.0013	830	$ 1.08	$ 0.07	7.46%
Sub-Total C - Delivery (including Sub-Total B)				**$ 41.77**			**$ 38.29**	**-$ 3.48**	**-8.32%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	837	$ 3.68	$ 0.0044	830	$ 3.65	-$ 0.03	-0.80%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	837	$ 1.00	$ 0.0012	830	$ 1.00	-$ 0.01	-0.80%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0720	512	$ 36.86	$ 0.0720	512	$ 36.86	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1090	144	$ 15.70	$ 0.1090	144	$ 15.70	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1290	144	$ 18.58	$ 0.1290	144	$ 18.58	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0830	800	$ 66.40	$ 0.0830	800	$ 66.40	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0970	0	$ -	$ 0.0970	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 123.44**			**$ 119.93**	**-$ 3.51**	**-2.85%**
HST		13%		$ 16.05	13%		$ 15.59	-$ 0.46	-2.85%
Total Bill (including HST)				$ 139.49			$ 135.52	-$ 3.97	-2.85%
Ontario Clean Energy Benefit [1]				-$ 13.95			-$ 13.55	$ 0.40	-2.87%
Total Bill on TOU (including OCEB)				**$ 125.54**			**$ 121.97**	**-$ 3.57**	**-2.84%**
Total Bill on RPP (before Taxes)				**$ 118.70**			**$ 115.19**	**-$ 3.51**	**-2.96%**
HST		13%		$ 15.43	13%		$ 14.97	-$ 0.46	-2.96%
Total Bill (including HST)				$ 134.14			$ 130.16	-$ 3.97	-2.96%
Ontario Clean Energy Benefit [1]				-$ 13.41			-$ 13.02	$ 0.39	-2.91%
Total Bill on RPP (including OCEB)				**$ 120.73**			**$ 117.14**	**-$ 3.58**	**-2.97%**

Loss Factor (%) 4.63% 3.79%

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

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Customer Class: **General Service Less than 50kW**

TOU / non-TOU: TOU

Consumption **2,000** **kWh** May 1 - October 31

	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	$ 45.9700	1	$ 45.97	$ 37.2800	1	$ 37.28	-$ 8.69	-18.90%
Smart Meter Disposition	Monthly	$ 3.1500	1	$ 3.15	$ -	1	$ -	-$ 3.15	-100.00%
SMIRR Recovery	Monthly	$ 4.8500	1	$ 4.85	$ -	1	$ -	-$ 4.85	-100.00%
Stranded Meter recovery	Monthly	$ -	1	$ -	$ 1.0600	1	$ 1.06	$ 1.06	
Distribution Volumetric Rate	per kWh	$ 0.0138	2000	$ 27.60	$ 0.0112	2000	$ 22.40	-$ 5.20	-18.84%
Sub-Total A (excluding pass through)				$ 81.57			$ 60.74	**-$ 20.83**	**-25.54%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0006	2000	-$ 1.20	-$ 0.0020	2000	-$ 4.00	-$ 2.80	233.33%
DVA 1562 disposition	per kWh	-$ 0.0011	2000	-$ 2.20	$ -	2000	$ -	$ 2.20	-100.00%
Tax change rider	per kWh	-$ 0.0005	2000	-$ 1.00	$ -	2000	$ -	$ 1.00	-100.00%
DVA 1576 Disposition Rider	per kWh	$ -	2000	$ -	-$ 0.0010	2000	-$ 2.00	-$ 2.00	
Line Losses on Cost of Power		$ 0.0889	92.60	$ 8.23	$ 0.0889	75.80	$ 6.74	-$ 1.49	-18.14%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 86.19**			**$ 62.27**	**-$ 23.92**	**-27.76%**
RTSR - Network	per kWh	$ 0.0064	2093	$ 13.39	$ 0.0066	2076	$ 13.70	$ 0.31	2.30%
RTSR - Line and Transformation Connection	per kWh	$ 0.0012	2093	$ 2.51	$ 0.0013	2076	$ 2.70	$ 0.19	7.46%
Sub-Total C - Delivery (including Sub-Total B)				**$ 102.10**			**$ 78.67**	**-$ 23.43**	**-22.95%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2093	$ 9.21	$ 0.0044	2076	$ 9.13	-$ 0.07	-0.80%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	2093	$ 2.51	$ 0.0012	2076	$ 2.49	-$ 0.02	-0.80%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0720	1280	$ 92.16	$ 0.0720	1280	$ 92.16	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1090	360	$ 39.24	$ 0.1090	360	$ 39.24	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1290	360	$ 46.44	$ 0.1290	360	$ 46.44	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0830	750	$ 62.25	$ 0.0830	750	$ 62.25	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0970	1250	$ 121.25	$ 0.0970	1250	$ 121.25	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 305.91**			**$ 282.38**	**-$ 23.52**	**-7.69%**
HST		13%		$ 39.77	13%		$ 36.71	-$ 3.06	-7.69%
Total Bill (including HST)				$ 345.67			$ 319.09	-$ 26.58	-7.69%
Ontario Clean Energy Benefit [1]				-$ 34.57			-$ 31.91	$ 2.66	-7.69%
Total Bill on TOU (including OCEB)				**$ 311.10**			**$ 287.18**	**-$ 23.92**	**-7.69%**
Total Bill on RPP (before Taxes)				**$ 311.57**			**$ 288.04**	**-$ 23.52**	**-7.55%**
HST		13%		$ 40.50	13%		$ 37.45	-$ 3.06	-7.55%
Total Bill (including HST)				$ 352.07			$ 325.49	-$ 26.58	-7.55%
Ontario Clean Energy Benefit [1]				-$ 35.21			-$ 32.55	$ 2.66	-7.55%
Total Bill on RPP (including OCEB)				**$ 316.86**			**$ 292.94**	**-$ 23.92**	**-7.55%**

Loss Factor (%) Current: 4.63% Proposed: 3.79%

Customer Class: **General Service 50 to 4,999 kW**

TOU / non-TOU: non-TOU

Consumption: 56,000 kWh; 150 kW — May 1 - October 31

	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	$ 328.4100	1	$ 328.41	$ 266.4200	1	$ 266.42	-$ 61.99	-18.88%
Distribution Volumetric Rate	per kW	$ 2.5664	150	$ 384.96	$ 2.1025	150	$ 315.38	-$ 69.58	-18.08%
Sub-Total A (excluding pass through)				$ 713.37			$ 581.80	**-$ 131.57**	**-18.44%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.1856	150	-$ 27.84	-$ 1.3909	150	-$ 208.63	-$ 180.79	649.38%
DVA Rate Rider Non-RPP	per kW	$ 2.1024	150	$ 315.36	-$ 0.8249				
DVA 1562 disposition	per kW	-$ 0.1744	150	-$ 26.16	$ -	150	$ -	$ 26.16	-100.00%
Tax change rider	per kW	-$ 0.0802	150	-$ 12.03	$ -	150	$ -	$ 12.03	-100.00%
DVA 1576 Disposition Rider	per kW	$ -	150	$ -	-$ 0.3760	150	-$ 56.40	-$ 56.40	
Line Losses on Cost of Power		$ 0.0876	2,592.80	$ 227.13	$ 0.0876	2,122.40	$ 185.92	-$ 41.21	-18.14%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 1,189.83**			**$ 502.69**	**-$ 687.14**	**-57.75%**
RTSR - Network	per kW	$ 2.5928	150	$ 388.92	$ 2.6853	150	$ 402.80	$ 13.87	3.57%
RTSR - Line and Transformation Connection	per kW	$ 0.4315	150	$ 64.73	$ 0.4602	150	$ 69.03	$ 4.31	6.65%
Sub-Total C - Delivery (including Sub-Total B)				**$ 1,643.47**			**$ 974.51**	**-$ 668.96**	**-40.70%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	56000	$ 246.40	$ 0.0044	56000	$ 246.40	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	56000	$ 67.20	$ 0.0012	56000	$ 67.20	$ -	0.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	56000	$ 392.00	$ 0.0070	56000	$ 392.00	$ -	0.00%
Energy - Non RPP	per kWh	$ 0.0876	56000	$ 4,905.60	$ 0.0876	56000	$ 4,905.60	$ -	0.00%
Total Bill (before Taxes)				**$ 7,254.92**			**$ 6,585.96**	**-$ 668.96**	**-9.22%**
HST		13%		$ 943.14	13%		$ 856.17	-$ 86.97	-9.22%
Total Bill (including HST)				$ 8,198.06			$ 7,442.14	-$ 755.93	-9.22%
Total Bill				**$ 8,198.06**			**$ 7,442.14**	**-$ 755.93**	**-9.22%**

Loss Factor (%): Current 4.63%; Proposed 3.79%

Customer Class: **Street Lighting**

TOU / non-TOU: non-TOU

Consumption 50 kWh ○ May 1 - October 31
0.14 kW

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 4.9800	1	$ 4.98	$ 7.4200	1	$ 7.42	$ 2.44	49.00%
Distribution Volumetric Rate	per kW	$ 19.4795	0.14	$ 2.73	$ 29.0338	0.14	$ 4.06	$ 1.34	49.05%
Sub-Total A (excluding pass through)				$ 7.71			$ 11.48	**$ 3.78**	**49.01%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.1611	0.14	-$ 0.02	-$ 1.1086	0.14	-$ 0.16	-$ 0.13	588.16%
DVA Rate Rider Non-RPP	per kW	$ 1.8803	0.14	$ 0.26	-$ 0.7620	0.14	-$ 0.11	-$ 0.37	-140.53%
DVA 1562 disposition	per kW	-$ 2.4982	0.14	-$ 0.35	$ -	0.14	$ -	$ 0.35	-100.00%
Tax change rider	per kW	-$ 0.9793	0.14	-$ 0.14	$ -	0.14	$ -	$ 0.14	-100.00%
DVA 1576 Disposition Rider	per kW	$ -	0.14	$ -	-$ 0.3473	0.14	-$ 0.05	-$ 0.05	
Line Losses on Cost of Power		$ 0.0876	0.01	$ 0.00	$ 0.0876	0.01	$ 0.00	-$ 0.00	-18.14%
Smart Meter Entity Charge			1	$ -		1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 7.46**			**$ 11.17**	**$ 3.71**	**49.76%**
RTSR - Network	per kW	$ 1.9552	0.14	$ 0.27	$ 2.0249	0.14	$ 0.28	$ 0.01	3.56%
RTSR - Line and Transformation Connection	per kW	$ 0.3336	0.14	$ 0.05	$ 0.3558	0.14	$ 0.05	$ 0.00	6.65%
Sub-Total C - Delivery (including Sub-Total B)				**$ 7.78**			**$ 11.51**	**$ 3.73**	**47.88%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	50	$ 0.22	$ 0.0044	50	$ 0.22	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	50	$ 0.06	$ 0.0012	50	$ 0.06	$ -	0.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	50	$ 0.35	$ 0.0070	50	$ 0.35	$ -	0.00%
Energy - Non RPP	per kWh	$ 0.0876	50	$ 4.38	$ 0.0876	50	$ 4.38	$ -	0.00%
Total Bill (before Taxes)				**$ 13.04**			**$ 16.77**	**$ 3.73**	**28.57%**
HST		13%		$ 1.70	13%		$ 2.18	$ 0.48	28.57%
Total Bill (including HST)				$ 14.74			$ 18.95	$ 4.21	28.57%
Total Bill				**$ 14.74**			**$ 18.95**	**$ 4.21**	**28.57%**

Loss Factor (%) 4.63% 3.79%

Customer Class: Unmetered Scattered Load

TOU / non-TOU: TOU

Consumption 900 kWh ○ May 1 - October 31

	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	$ 54.3100	1	$ 54.31	$ 20.0500	1	$ 20.05	-$ 34.26	-63.08%
Distribution Volumetric Rate	per kWh	$ 0.0163	900	$ 14.67	$ 0.0060	900	$ 5.41	-$ 9.26	-63.09%
Sub-Total A (excluding pass through)				$ 68.98			$ 25.46	**-$ 43.52**	**-63.08%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0008	900	-$ 0.72	-$ 0.0006	900	-$ 0.54	$ 0.18	-25.00%
DVA 1562 disposition	per kWh	-$ 0.0037	900	-$ 3.33	$ -	900	$ -	$ 3.33	-100.00%
Tax change rider	per kWh	-$ 0.0014	900	-$ 1.26	$ -	900	$ -	$ 1.26	-100.00%
DVA 1576 Disposition Rider	per kWh	$ -	900	$ -	-$ 0.0010	900	-$ 0.87	-$ 0.87	
Line Losses on Cost of Power		$ 0.0889	41.67	$ 3.71	$ 0.0889	34.11	$ 3.03	-$ 0.67	-18.14%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 67.38**			**$ 27.09**	**-$ 40.29**	**-59.80%**
RTSR - Network	per kWh	$ 0.0064	942	$ 6.03	$ 0.0066	934	$ 6.17	$ 0.14	2.30%
RTSR - Line and Transformation Connection	per kWh	$ 0.0012	942	$ 1.13	$ 0.0013	934	$ 1.21	$ 0.08	7.46%
Sub-Total C - Delivery (including Sub-Total B)				**$ 74.53**			**$ 34.47**	**-$ 40.06**	**-53.75%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	942	$ 4.14	$ 0.0044	934	$ 4.11	-$ 0.03	-0.80%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	942	$ 1.13	$ 0.0012	934	$ 1.12	-$ 0.01	-0.80%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	900	$ 6.30	$ 0.0070	900	$ 6.30	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0720	576	$ 41.47	$ 0.0720	576	$ 41.47	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1090	162	$ 17.66	$ 0.1090	162	$ 17.66	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1290	162	$ 20.90	$ 0.1290	162	$ 20.90	$ -	0.00%
Energy - RPP - Tier 1	per kWh	$ 0.0830	750	$ 62.25	$ 0.0830	750	$ 62.25	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0970	150	$ 14.55	$ 0.0970	150	$ 14.55	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 166.38**			**$ 126.28**	**-$ 40.11**	**-24.11%**
HST		13%		$ 21.63	13%		$ 16.42	-$ 5.21	-24.11%
Total Bill (including HST)				$ 188.01			$ 142.69	-$ 45.32	-24.11%
Ontario Clean Energy Benefit [1]				-$ 18.80			-$ 14.27	$ 4.53	-24.10%
Total Bill on TOU (including OCEB)				**$ 169.21**			**$ 128.42**	**-$ 40.79**	**-24.11%**
Total Bill on RPP (before Taxes)				**$ 163.16**			**$ 123.05**	**-$ 40.11**	**-24.58%**
HST		13%		$ 21.21	13%		$ 16.00	-$ 5.21	-24.58%
Total Bill (including HST)				$ 184.37			$ 139.04	-$ 45.32	-24.58%
Ontario Clean Energy Benefit [1]				-$ 18.44			-$ 13.90	$ 4.54	-24.62%
Total Bill on RPP (including OCEB)				**$ 165.93**			**$ 125.14**	**-$ 40.78**	**-24.58%**

Loss Factor (%) — Current: 4.63% — Proposed: 3.79%

Appendix 5

PILS Work Form

Income Tax/PILs Workform for 2014 Filers

Version **2.0**

Utility Name	Niagara-on-the-Lake Hydro Inc.
Assigned EB Number	EB-2013-0155
Name and Title	Philip Wormwell, Director of Corporate Services
Phone Number	905-468-8608 Ext 380
Email Address	pwormwell@notlhydro.com
Date	6-Mar-14
Last COS Re-based Year	**2009**

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

Income Tax/PILs Workform for 2014 Filers

1. Info
A. Data Input Sheet
B. Tax Rates & Exemptions
C. Sch 8 Hist
D. Schedule 10 CEC Hist
E. Sch 13 Tax Reserves Hist
F. Sch 7-1 Loss Cfwd Hist
G. Adj. Taxable Income Historic
H. PILs,Tax Provision Historic
I. Schedule 8 CCA Bridge Year
J. Schedule 10 CEC Bridge Year
K. Sch 13 Tax Reserves Bridge
L. Sch 7-1 Loss Cfwd Bridge
M. Adj. Taxable Income Bridge
N. PILs,Tax Provision Bridge
O. Schedule 8 CCA Test Year
P. Schedule 10 CEC Test Year
Q Sch 13 Tax Reserve Test Year
R. Sch 7-1 Loss Cfwd
S. Taxable Income Test Year
T. PILs,Tax Provision

Income Tax/PILs
Workform for 2014 Filers

Rate Base			**$**	**24,483,958**	
Return on Ratebase					
Deemed ShortTerm Debt %	4.00%	T	$	979,358	*W = S * T*
Deemed Long Term Debt %	56.00%	U	$	13,711,016	*X = S * U*
Deemed Equity %	40.00%	V	$	9,793,583	*Y = S * V*
Short Term Interest Rate	2.11%	Z	$	20,664	*AC = W * Z*
Long Term Interest	4.96%	AA	$	680,095	*AD = X * AA*
Return on Equity (Regulatory Income)	9.36%	AB	**$**	**916,679**	*AE = Y * AB*
Return on Rate Base			**$**	**1,617,439**	*AF = AC + AD + AE*

Questions that must be answered

	Historic	Bridge	Test Year
1. Does the applicant have any Investment Tax Credits (ITC)?	Yes	No	No
2. Does the applicant have any SRED Expenditures?	No	No	No
3. Does the applicant have any Capital Gains or Losses for tax purposes?	No	No	No
4. Does the applicant have any Capital Leases?	No	No	No
5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	No	No	No
6. Since 1999, has the applicant acquired another regulated applicant's assets?	No	No	No
7. Did the applicant pay dividends? *If Yes, please describe what was the tax treatment in the manager's summary.*	No	No	No
8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes?	No	No	No

Income Tax/PILs Workform for 2014 Filers

Tax Rates Federal & Provincial As of June 20, 2012	Effective ################	Effective ################	Effective ################	Effective ################
Federal income tax				
General corporate rate	38.00%	38.00%	38.00%	38.00%
Federal tax abatement	-10.00%	-10.00%	-10.00%	-10.00%
Adjusted federal rate	28.00%	28.00%	28.00%	28.00%
Rate reduction	-11.50%	-13.00%	-13.00%	-13.00%
	16.50%	15.00%	15.00%	15.00%
Ontario income tax	11.75%	11.50%	11.50%	11.50%
Combined federal and Ontario	28.25%	26.50%	26.50%	26.50%
Federal & Ontario Small Business				
Federal small business threshold	500,000	500,000	500,000	500,000
Ontario Small Business Threshold	500,000	500,000	500,000	500,000
Federal small business rate	11.00%	11.00%	11.00%	11.00%
Ontario small business rate	4.50%	4.50%	4.50%	4.50%

Income Tax/PILs Workform for 2014 Filers

Schedule 8 - Historical Year

Class	Class Description	UCC End of Year Historic per tax returns	Less: Non-Distribution Portion	UCC Regulated Historic Year
1	Distribution System - post 1987	10,092,052		10,092,052
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	96,558		96,558
2	Distribution System - pre 1988	3,349,969		3,349,969
8	General Office/Stores Equip	385,575		385,575
10	Computer Hardware/ Vehicles	353,014		353,014
10.1	Certain Automobiles			0
12	Computer Software	57,669		57,669
13_1	Lease # 1			0
13_2	Lease #2			0
13_3	Lease # 3			0
13_4	Lease # 4			0
14	Franchise			0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	25,277		25,277
42	Fibre Optic Cable			0
43.1	Certain Energy-Efficient Electrical Generating Equipment			0
43.2	Certain Clean Energy Generation Equipment			0
45	Computers & Systems Software acq'd post Mar 22/04	563		563
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)			0
47	Distribution System - post February 2005	9,501,812		9,501,812
50	Data Network Infrastructure Equipment - post Mar 2007	16,642		16,642
52	Computer Hardware and system software			0
95	CWIP			0
				0
6	Fencing	3,670		3,670
				0
				0
				0
				0
				0
				0
				0
				0
	SUB-TOTAL - UCC	23,882,801	0	23,882,801

Income Tax/PILs Workform for 2014 Filers

Schedule 10 CEC - Historical Year

Cumulative Eligible Capital				**11,359**
Additions				
Cost of Eligible Capital Property Acquired during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**11,359**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**11,359**
Current Year Deduction		**11,359**	**x 7% =**	**795**
Cumulative Eligible Capital - Closing Balance				**10,564**

Schedule 13 Tax Reserves - Historical

Continuity of Reserves

Description	Historical Balance as per tax returns	Non-Distribution Eliminations	Utility Only
Capital Gains Reserves ss.40(1)			0
Tax Reserves Not Deducted for accounting purposes			
Reserve for doubtful accounts ss. 20(1)(l)	30,000		30,000
Reserve for goods and services not delivered ss. 20(1)(m)			0
Reserve for unpaid amounts ss. 20(1)(n)			0
Debt & Share Issue Expenses ss. 20(1)(e)			0
Other tax reserves			0
			0
			0
			0
			0
			0
Total	**30,000**	**0**	**30,000**
Financial Statement Reserves (not deductible for Tax Purposes)			
General Reserve for Inventory Obsolescence (non-specific)			0
General reserve for bad debts	30,000		30,000
Accrued Employee Future Benefits:			0
- Medical and Life Insurance	440,376		440,376
-Short & Long-term Disability			0
-Accmulated Sick Leave			0
- Termination Cost			0
- Other Post-Employment Benefits			0
Provision for Environmental Costs			0
Restructuring Costs			0
Accrued Contingent Litigation Costs			0
Accrued Self-Insurance Costs			0
Other Contingent Liabilities			0
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0
Other			0
			0
			0
Total	**470,376**	**0**	**470,376**

Income Tax/PILs Workform for 2014 Filers

Schedule 7-1 Loss Carry Forward - Historic

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	**Total**	**Non-Distribution Portion**	**Utility Balance**
Actual Historic			0

Net Capital Loss Carry Forward Deduction	**Total**	**Non-Distribution Portion**	**Utility Balance**
Actual Historic			0

Income Tax/PILs Workform for 2014 Filers

Adjusted Taxable Income - Historic Year

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Income before PILs/Taxes	A	501,449		501,449
Additions:				
Interest and penalties on taxes	103			0
Amortization of tangible assets	104	1,782,092		1,782,092
Amortization of intangible assets	106			0
Recapture of capital cost allowance from Schedule 8	107			0
Gain on sale of eligible capital property from Schedule 10	108			0
Income or loss for tax purposes- joint ventures or partnerships	109			0
Loss in equity of subsidiaries and affiliates	110			0
Loss on disposal of assets	111	51,592		51,592
Charitable donations	112	774		774
Taxable Capital Gains	113			0
Political Donations	114			0
Deferred and prepaid expenses	116			0
Scientific research expenditures deducted on financial statements	118			0
Capitalized interest	119			0
Non-deductible club dues and fees	120			0
Non-deductible meals and entertainment expense	121			0
Non-deductible automobile expenses	122			0
Non-deductible life insurance premiums	123			0
Non-deductible company pension plans	124			0
Tax reserves deducted in prior year	125			0
Reserves from financial statements- balance at end of year	126	470,376		470,376
Soft costs on construction and renovation of buildings	127			0
Book loss on joint ventures or partnerships	205			0
Capital items expensed	206			0
Debt issue expense	208			0
Development expenses claimed in current year	212			0
Financing fees deducted in books	216			0
Gain on settlement of debt	220			0
Non-deductible advertising	226			0
Non-deductible interest	227			0
Non-deductible legal and accounting fees	228			0
Recapture of SR&ED expenditures	231			0
Share issue expense	235			0
Write down of capital property	236			0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237			0
Other Additions				
Interest Expensed on Capital Leases	290			0
Realized Income from Deferred Credit Accounts	291			0
Pensions	292			0
Non-deductible penalties	293	1,304,092		1,304,092
Additional Amortization booled to P&L	294	32,864		32,864
	295			0
ARO Accretion expense				0
Capital Contributions Received (ITA 12(1)(x))				0
Lease Inducements Received (ITA 12(1)(x))				0
Deferred Revenue (ITA 12(1)(a))				0
Prior Year Investment Tax Credits received				0
				0

Provision for income taxes - current [T2S1 Line 101]		462,731		462,731
Provision for income taxes - deferred [T2S1 Line 102]		-306,381		-306,381
				0
				0
				0
				0
				0
				0
				0
Total Additions		**3,798,140**	**0**	**3,798,140**
Deductions:				
Gain on disposal of assets per financial statements	401			0
Dividends not taxable under section 83	402			0
Capital cost allowance from Schedule 8	403	1,690,370		1,690,370
Terminal loss from Schedule 8	404			0
Cumulative eligible capital deduction from Schedule 10	405	795		795
Allowable business investment loss	406			0
Deferred and prepaid expenses	409			0
Scientific research expenses claimed in year	411			0
Tax reserves claimed in current year	413			0
Reserves from financial statements - balance at beginning of year	414	459,058		459,058
Contributions to deferred income plans	416			0
Book income of joint venture or partnership	305			0
Equity in income from subsidiary or affiliates	306			0
Other deductions: (Please explain in detail the nature of the item)				
Interest capitalized for accounting deducted for tax	390	118,201		118,201
Capital Lease Payments	391	61,834		61,834
Non-taxable imputed interest income on deferral and variance accounts	392			0
	393			0
	394			0
ARO Payments - Deductible for Tax when Paid				0
ITA 13(7.4) Election - Capital Contributions Received				0
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds				0
Deferred Revenue - ITA 20(1)(m) reserve				0
Principal portion of lease payments				0
Lease Inducement Book Amortization credit to income				0
Financing fees for tax ITA 20(1)(e) and (e.1)				0
				0
				0
				0
				0
				0
				0
				0
Total Deductions		**2,330,258**	**0**	**2,330,258**
Net Income for Tax Purposes		**1,969,331**	**0**	**1,969,331**
Charitable donations from Schedule 2	311	3,774		3,774
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320			0
Non-capital losses of preceding taxation years from Schedule 4	331			0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332			0
Limited partnership losses of preceding taxation years from Schedule 4	335			0
TAXABLE INCOME		**1,965,557**	**0**	**1,965,557**

Income Tax/PILs Workform for 2014 Filers

PILs Tax Provision - Historic Year

Note: Input the actual information from the tax returns for the historic year.

					Wires Only	
Regulatory Taxable Income					$ 1,965,557	**A**
Ontario Income Taxes						
Income tax payable	**Ontario Income Tax**	11.50%	**B**	$ 226,039 **C = A * B**		
Small business credit	Ontario Small Business Threshold	$ 500,000	**D**			
	Rate reduction (negative)	-7.00%	**E**	-$ 35,000 **F = D * E**		
Ontario Income tax					$ 191,039	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			9.72% **K = J / A**		
	Federal tax rate			15.00% **L**		
	Combined tax rate				24.72%	**M = K + L**
Total Income Taxes					**$ 485,873**	**N = A * M**
Investment Tax Credits					$ 28,856	**O**
Miscellaneous Tax Credits						**P**
Total Tax Credits					**$ 28,856**	**Q = O + P**
Corporate PILs/Income Tax Provision for Historic Year					**$ 457,017**	**R = N - Q**

Schedule 8 CCA - Bridge Year

Class	Class Description	UCC Regulated Historic Year	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Bridge Year CCA	UCC End of Bridge Year
1	Distribution System - post 1987	$ 10,092,052	$ -	$ -	$ 10,092,052	$ -	$ 10,092,052	4%	$ 403,682	$ 9,688,370
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ 96,558	$ -	$ -	$ 96,558	$ -	$ 96,558	6%	$ 5,793	$ 90,765
2	Distribution System - pre 1988	$ 3,349,969	$ -	$ -	$ 3,349,969	$ -	$ 3,349,969	6%	$ 200,998	$ 3,148,971
8	General Office/Stores Equip	$ 385,575	$ 5,751	$ -	$ 391,326	$ 2,875	$ 388,450	20%	$ 77,690	$ 313,636
10	Computer Hardware/ Vehicles	$ 353,014	$ 53,681	-$ 35,341	$ 371,354	$ 9,170	$ 362,184	30%	$ 108,655	$ 262,699
10.1	Certain Automobiles				$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 57,669	$ 104,895	$ -	$ 162,564	$ 52,448	$ 110,117	100%	$ 110,117	$ 52,448
13 1	Lease # 1				$ -	$ -	$ -		$ -	$ -
13 2	Lease #2				$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3				$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4				$ -	$ -	$ -		$ -	$ -
14	Franchise				$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 25,277	$ -	$ -	$ 25,277	$ -	$ 25,277	8%	$ 2,022	$ 23,255
42	Fibre Optic Cable				$ -	$ -	$ -	12%	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment				$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment				$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 563	$ -	$ -	$ 563	$ -	$ 563	45%	$ 253	$ 310
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)				$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 9,501,812	$ 1,357,079	-$ 425,970	$ 10,432,921	$ 465,554	$ 9,967,366	8%	$ 797,389	$ 9,635,532
50	Data Network Infrastructure Equipment - post Mar 2007	$ 16,642	$ 38,762	$ -	$ 55,404	$ 19,381	$ 36,023	55%	$ 19,813	$ 35,591
52	Computer Hardware and system software				$ -	$ -	$ -	100%	$ -	$ -
95	CWIP				$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
6	Fencing	$ 3,670	$ -	$ -	$ 3,670	$ -	$ 3,670	10%	$ 367	$ 3,303
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
	TOTAL	$ 23,882,801	$ 1,560,167	-$ 461,310	$ 24,981,658	$ 549,429	$ 24,432,230		$ 1,726,780	$ 23,254,878

Income Tax/PILs Workform for 2014 Filers

Schedule 10 CEC - Bridge Year

Cumulative Eligible Capital				**10,564**
Additions				
Cost of Eligible Capital Property Acquired during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**10,564**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**10,564**
Current Year Deduction		**10,564**	**x 7% =**	**739**
Cumulative Eligible Capital - Closing Balance				**9,824**

Schedule 13 Tax Reserves - Bridge Year

Continuity of Reserves

Description	Historic Utility Only	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance	Bridge Year Adjustments: Additions	Bridge Year Adjustments: Disposals	Balance for Bridge Year	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	0		0			0	0	
Tax Reserves Not Deducted for accounting purposes								
Reserve for doubtful accounts ss. 20(1)(l)	30,000		30,000	30,000	30,000	30,000	0	
Reserve for goods and services not delivered ss. 20(1)(m)	0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0		0			0	0	
Other tax reserves	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**30,000**	**0**	**30,000**	**30,000**	**30,000**	**30,000**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)								
General Reserve for Inventory Obsolescence (non-specific)	0		0			0	0	
General reserve for bad debts	30,000		30,000	30,000	30,000	30,000	0	
Accrued Employee Future Benefits:	0		0			0	0	
- Medical and Life Insurance	440,376		440,376	428,290	440,376	428,290	-12,086	
-Short & Long-term Disability	0		0			0	0	
-Accmulated Sick Leave	0		0			0	0	
- Termination Cost	0		0			0	0	
- Other Post-Employment Benefits	0		0			0	0	
Provision for Environmental Costs	0		0			0	0	
Restructuring Costs	0		0			0	0	
Accrued Contingent Litigation Costs	0		0			0	0	
Accrued Self-Insurance Costs	0		0			0	0	
Other Contingent Liabilities	0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	0		0			0	0	
Other	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**470,376**	**0**	**470,376**	**458,290**	**470,376**	**458,290**	**-12,086**	**0**

Income Tax/PILs Workform for 2014 Filers

Corporation Loss Continuity and Application

Schedule 7-1 Loss Carry Forward - Bridge Year

Non-Capital Loss Carry Forward Deduction	**Total**
Actual Historic	0
Application of Loss Carry Forward to reduce taxable income in Bridge Year	
Other Adjustments Add (+) Deduct (-)	
Balance available for use in Test Year	0
Amount to be used in Bridge Year	
Balance available for use post Bridge Year	0

Net Capital Loss Carry Forward Deduction	**Total**
Actual Historic	0
Application of Loss Carry Forward to reduce taxable income in Bridge Year	
Other Adjustments Add (+) Deduct (-)	
Balance available for use in Test Year	0
Amount to be used in Bridge Year	
Balance available for use post Bridge Year	0

Income Tax/PILs Workform for 2014 Filers

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Total for Regulated Utility
Income before PILs/Taxes	**A**	610,746
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets	104	1,088,857
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	100,759
Charitable donations	112	5,500
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves deducted in prior year	125	30,000
Reserves from financial statements- balance at end of year	126	458,290
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	

Income Tax/PILs Workform for 2014 Filers

Adjusted Taxable Income - Bridge Year

Other Additions		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
	294	
Apprenticeship tax credit	295	7,000
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		
Total Additions		**1,690,406**
Deductions:		
Gain on disposal of assets per financial statements	401	0
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	1,726,780
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10	405	739
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves claimed in current year	413	30,000
Reserves from financial statements - balance at beginning of year	414	470,376
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		

Income Tax/PILs Workform for 2014 Filers

Adjusted Taxable Income - Bridge Year

Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	
Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to income		
Financing fees for tax ITA 20(1)(e) and (e.1)		
Total Deductions		**2,227,896**
Net Income for Tax Purposes		**73,256**
Charitable donations from Schedule 2	311	5,500
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320	
Non-capital losses of preceding taxation years from Schedule 4	331	
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
TAXABLE INCOME		**67,756**

Income Tax/PILs Workform for 2014 Filers

PILS Tax Provision - Bridge Year

							Wires Only	
Regulatory Taxable Income							$ 67,756	**A**
Ontario Income Taxes								
Income tax payable	**Ontario Income Tax**	4.50%	**B**	$	3,049	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ -	**D**					
	Rate reduction	-7.00%	**E**	$	-	**F = D * E**		
Ontario Income tax							$ 3,049	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate				4.50%	**K = J / A**		
	Federal tax rate				11.00%	**L**		
	Combined tax rate						15.50%	**M = K + L**
Total Income Taxes							**$ 10,502**	**N = A * M**
Investment Tax Credits							$ -	**O**
Miscellaneous Tax Credits							$ 7,000	**P**
Total Tax Credits							**$ 7,000**	**Q = O + P**
Corporate PILs/Income Tax Provision for Bridge Year							**$ 3,502**	**R = N - Q**

Note:

1. This is for the derivation of Bridge year PILs income tax expense and should not be used for Test year revenue requirement calculations.

Income Tax/PILs
Workform for 2014 Filers

Schedule 8 CCA - Test Year

Class	Class Description	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	$ 9,688,370	$ -	$ -	$ 9,688,370	$ -	$ 9,688,370	4%	$ 387,535	$ 9,300,835
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ 90,765	$ -	$ -	$ 90,765	$ -	$ 90,765	6%	$ 5,446	$ 85,319
2	Distribution System - pre 1988	$ 3,148,971	$ -	$ -	$ 3,148,971	$ -	$ 3,148,971	6%	$ 188,938	$ 2,960,033
8	General Office/Stores Equip	$ 313,636	$ 15,000	$ -	$ 328,636	$ 7,500	$ 321,136	20%	$ 64,227	$ 264,409
10	Computer Hardware/ Vehicles	$ 262,699	$ -	$ -	$ 262,699	$ -	$ 262,699	30%	$ 78,810	$ 183,889
10.1	Certain Automobiles	$ -			$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 52,448	$ 190,000	$ -	$ 242,448	$ 95,000	$ 147,448	100%	$ 147,448	$ 95,000
13 1	Lease # 1	$ -			$ -	$ -	$ -		$ -	$ -
13 2	Lease #2	$ -			$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3	$ -			$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4	$ -			$ -	$ -	$ -		$ -	$ -
14	Franchise	$ -			$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bl	$ 23,255	$ -	$ -	$ 23,255	$ -	$ 23,255	8%	$ 1,860	$ 21,394
42	Fibre Optic Cable	$ -			$ -	$ -	$ -	12%	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -			$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment	$ -			$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 310	$ -	$ -	$ 310	$ -	$ 310	45%	$ 139	$ 170
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ -			$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 9,635,532	$ 1,075,000	-$ 477,000	$ 10,233,532	$ 299,000	$ 9,934,532	8%	$ 794,763	$ 9,438,769
50	Data Network Infrastructure Equipment - post Mar 2007	$ 35,591	$ 5,000	$ -	$ 40,591	$ 2,500	$ 38,091	55%	$ 20,950	$ 19,641
52	Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ -			$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
6	Fencing	$ 3,303	$ -	$ -	$ 3,303	$ -	$ 3,303	10%	$ 330	$ 2,973
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	$ 23,254,878	$ 1,285,000	-$ 477,000	$ 24,062,878	$ 404,000	$ 23,658,878		$ 1,690,446	$ 22,372,432

Income Tax/PILs Workform for 2014 Filers

Schedule 10 CEC - Test Year

Cumulative Eligible Capital				9,824
Additions				
Cost of Eligible Capital Property Acquired during Test Year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	x 1/2 =	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**9,824**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =		**0**
Cumulative Eligible Capital Balance				**9,824**
Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")		**9,824**	**x 7% =**	**688**
Cumulative Eligible Capital - Closing Balance				**9,137**

Schedule 13 Tax Reserves - Test Year

Continuity of Reserves

Description	Bridge Year	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance	Test Year Adjustments: Additions	Test Year Adjustments: Disposals	Balance for Test Year	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	0		0			0	0	
Tax Reserves Not Deducted for accounting purposes								
Reserve for doubtful accounts ss. 20(1)(l)	30,000		30,000	30,000	30,000	30,000	0	
Reserve for goods and services not delivered ss. 20(1)(m)	0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0		0			0	0	
Other tax reserves	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**30,000**	**0**	**30,000**	**30,000**	**30,000**	**30,000**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)								
General Reserve for Inventory Obsolescence (non-specific)	0		0			0	0	
General reserve for bad debts	30,000		30,000	30,000	30,000	30,000	0	
Accrued Employee Future Benefits:	0		0			0	0	
- Medical and Life Insurance	428,290		428,290	409,548	428,290	409,548	-18,742	
-Short & Long-term Disability	0		0			0	0	
-Accmulated Sick Leave	0		0			0	0	
- Termination Cost	0		0			0	0	
- Other Post-Employment Benefits	0		0			0	0	
Provision for Environmental Costs	0		0			0	0	
Restructuring Costs	0		0			0	0	
Accrued Contingent Litigation Costs	0		0			0	0	
Accrued Self-Insurance Costs	0		0			0	0	
Other Contingent Liabilities	0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	0		0			0	0	
Other	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**458,290**	**0**	**458,290**	**439,548**	**458,290**	**439,548**	**-18,742**	**0**

Schedule 7-1 Loss Carry Forward - Test Year

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	**Total**	**Non-Distribution Portion**	**Utility Balance**
Actual/Estimated Bridge Year			0
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year			0
Balance available for use post Test Year	0	0	0

Net Capital Loss Carry Forward Deduction	**Total**	**Non-Distribution Portion**	**Utility Balance**
Actual/Estimated Bridge Year			0
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year			0
Balance available for use post Test Year	0	0	0

Taxable Income - Test Year

	T2 S1 line #	Test Year Taxable Income
Net Income Before Taxes		916,679
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	1,005,631
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106	
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	30,000
Charitable donations	112	5,500
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves beginning of year	125	30,000
Reserves from financial statements- balance at end of year	126	439,548
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions: (please explain in detail the nature of the item)		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
	294	
Apprentice Tax Credits	295	12,000
	296	
	297	
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		
Total Additions		**1,522,679**
Deductions:		
Gain on disposal of assets per financial statements	401	
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	1,690,446
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10 CEC	405	688
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves end of year	413	30,000
Reserves from financial statements - balance at beginning of year	414	458,290
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	
Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
	395	
	396	
	397	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to income		
Financing fees for tax ITA 20(1)(e) and (e.1)		
Total Deductions		**2,179,424**
NET INCOME FOR TAX PURPOSES		**259,934**
Charitable donations	311	5,500
Taxable dividends received under section 112 or 113	320	
Non-capital losses of preceding taxation years from Schedule 7-1	331	
Net-capital losses of preceding taxation years (Please show calculation)	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
REGULATORY TAXABLE INCOME		**254,434**

PILs Tax Provision - Test Year

							Wires Only	
Regulatory Taxable Income							$ 254,434	**A**
Ontario Income Taxes								
Income tax payable	**Ontario Income Tax**	4.50%	**B**		$ 11,450	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ -	**D**					
	Rate reduction	-7.00%	**E**		$ -	**F = D * E**		
Ontario Income tax							$ 11,450	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			4.50%		**K = J / A**		
	Federal tax rate			11.00%		**L**		
	Combined tax rate						15.50%	**M = K + L**
Total Income Taxes							**$ 39,437**	**N = A * M**
Investment Tax Credits							$ -	**O**
Miscellaneous Tax Credits							$ 12,000	**P**
Total Tax Credits							**$ 12,000**	**Q = O + P**
Corporate PILs/Income Tax Provision for Test Year							**$ 27,437**	**R = N - Q**
Corporate PILs/Income Tax Provision Gross Up [1]				84.50%		**S = 1 - M**	**$ 5,033**	**T = R / S - R**
Income Tax (grossed-up)							**$ 32,470**	**U = R + T**

Note:

1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

Appendix 6 – 7.1

Table for Issue 7.1

Adjusted 2014 Cost of Power

2014 Load Forecast	**kWh**	**kW**	**2012 %RPP**		
Residential	67,753,410		97%		
General Service< 50 kW	37,260,698		91%		
General Service> 50 kW	81,473,856	201,178	7%		
Streetlights	1,248,464	3,377	9%		
Unmetered Loads	240,322		100%		
TOTAL	**187,976,750**	**204,554**			

Electricity - Commodity RPP					
Class per Load Forecast RPP	**2014 Forecasted Metered kWhs**	**2014 Loss Factor**		**2014**	
Residential	65,407,834	1.0379	67,886,790	$0.08900	$6,041,924
General Service< 50 kW	34,064,209	1.0379	35,355,242	$0.08900	$3,146,617
General Service> 50 kW	5,641,743	1.0379	5,855,565	$0.08900	$521,145
Streetlights	109,111	1.0379	113,246	$0.08900	$10,079
Unmetered Loads	240,322	1.0379	249,430	$0.08900	$22,199
TOTAL	**105,463,218**		**109,460,274**		**$9,741,964**

Electricity - Commodity Non-RPP					
Class per Load Forecast	**2014 Forecasted Metered kWhs**	**2014 Loss Factor**		**2014**	
Residential	2,345,576	1.0379	2,434,474	$0.08760	$213,260
General Service< 50 kW	3,196,489	1.0379	3,317,636	$0.08760	$290,625
General Service> 50 kW	75,832,113	1.0379	78,706,150	$0.08760	$6,894,659
Streetlights	1,139,353	1.0379	1,182,535	$0.08760	$103,590
Unmetered Loads	0	1.0379	0	$0.08760	$0
TOTAL	**82,513,532**		**85,640,795**		**$7,502,134**

Transmission - Network		**Volume**			
Class per Load Forecast		**Metric**		**2014**	
Residential		kWh	70,321,264	$0.0072	$506,313
General Service< 50 kW		kWh	38,672,879	$0.0066	$255,241
General Service> 50 kW		kW	201,178	$2.6853	$540,222
Streetlights		kW	3,377	$2.0249	$6,838
Unmetered Loads		kWh	249,430	$0.0066	$1,646
TOTAL					**$1,310,260**

Transmission - Connection		**Volume**			
Class per Load Forecast		**Metric**		**2014**	
Residential		kWh	70,321,264	$0.0013	$91,418
General Service< 50 kW		kWh	38,672,879	$0.0013	$50,275
General Service> 50 kW		kW	201,178	$0.4602	$92,582
Streetlights		kW	3,377	$0.3558	$1,201
Unmetered Loads		kWh	249,430	$0.0013	$324
TOTAL					**$235,800**

Wholesale Market Service					
Class per Load Forecast				**2014**	
Residential			70,321,264	$0.0044	$309,414
General Service< 50 kW			38,672,879	$0.0044	$170,161
General Service> 50 kW			84,561,715	$0.0044	$372,072
Streetlights			1,295,781	$0.0044	$5,701
Unmetered Loads			249,430	$0.0044	$1,097
TOTAL			**195,101,069**		**$858,445**

Rural Rate Assistance					
Class per Load Forecast				**2014**	
Residential			70,321,264	$0.0012	$84,386
General Service< 50 kW			38,672,879	$0.0012	$46,407
General Service> 50 kW			84,561,715	$0.0012	$101,474
Streetlights			1,295,781	$0.0012	$1,555
Unmetered Loads			249,430	$0.0012	$299
TOTAL			**195,101,069**		**$234,121**

	2014
4705-Power Purchased	$17,244,098
4708-Charges-WMS	$858,445
4714-Charges-NW	$1,310,260
4716-Charges-CN	$235,800
4730-Rural Rate Assistance	$234,121
4751 IESO SME Charges	$76,504
TOTAL	**19,959,228**

Appendix 6 – 7.2

Table for Issue 7.2

Fixed Asset Continuity schedule for 2014

Appendix 2-BA
Fixed Asset Continuity Schedule - CGAAP/ASPE/USGAAP

Year 2014

			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	$ 258,134	$ -	$ -	$ 258,134	$ -	$ -	$ -	$ -	$ 258,134
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Trans Stn Equip >50 Kv-Other-York	$ 1,915,162	$ 5,000	$ -	$ 1,920,162	-$ 481,216	-$ 32,174	$ -	-$ 513,390	$ 1,406,772
47	1815	Trans Stn Equip >50 Kv-Tx - York	$ 827,000	$ -	$ -	$ 827,000	-$ 214,176	-$ 17,763	$ -	-$ 231,939	$ 595,061
47	1815	Trans Stn Equip >50 Kv-Other-Conc 5	$ 2,010,750	$ -	$ -	$ 2,010,750	-$ 380,732	-$ 34,587	$ -	-$ 415,319	$ 1,595,431
47	1815	Trans Stn Equip >50 Kv-Tx -Conc 5	$ 670,096	$ -	$ -	$ 670,096	-$ 140,162	-$ 14,519	$ -	-$ 154,681	$ 515,416
47	1820	Distribution Station Equipment <50 kV	$ 160,630	$ -	$ -	$ 160,630	-$ 160,630	$ -	$ -	-$ 160,630	-$ 0
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 5,316,810	$ 224,000	-$ 182,000	$ 5,358,810	-$ 3,013,753	-$ 83,150	$ 182,000	-$ 2,914,903	$ 2,443,906
47	1835	Overhead Conductors & Devices	$ 6,756,920	$ 312,750	-$ 215,000	$ 6,854,670	-$ 3,857,169	-$ 72,925	$ 215,000	-$ 3,715,094	$ 3,139,576
47	1840	Underground Conduit	$ 5,249,706	$ 222,000	$ -	$ 5,471,706	-$ 2,335,640	-$ 56,562	$ -	-$ 2,392,202	$ 3,079,504
47	1845	Underground Conductors & Devices	$ 9,318,533	$ 285,000	$ -	$ 9,603,533	-$ 4,787,931	-$ 154,039	$ -	-$ 4,941,969	$ 4,661,563
47	1850	Line Transformers	$ 8,075,489	$ 241,250	-$ 80,000	$ 8,236,739	-$ 4,023,187	-$ 127,311	$ 50,000	-$ 4,100,497	$ 4,136,242
47	1855	Services - Overhead	$ 605,548	$ 25,000	$ -	$ 630,548	-$ 140,595	-$ 8,762	$ -	-$ 149,357	$ 481,191
47	1855	Services - Underground	$ 2,534,459	$ 215,000	$ -	$ 2,749,459	-$ 675,769	-$ 50,915	$ -	-$ 726,684	$ 2,022,776
47	1860	Meters - CT/PTs component	$ 452,958	$ -	$ 1,255	$ 454,213	-$ 325,197	-$ 4,483	$ -	-$ 329,680	$ 124,533
47	1860	Meters - Other component	$ 306,482	$ 30,000	-$ 1,255	$ 335,227	-$ 183,338	-$ 9,181	$ -	-$ 192,519	$ 142,708
47	1860	Meters - Stranded	$ -			$ -	$ -			$ -	$ -
47	1860	Meters (Smart Meters)	$ 1,718,509	$ 10,000	$ -	$ 1,728,509	-$ 395,502	-$ 114,901	$ -	-$ 510,402	$ 1,218,107
N/A	1905	Land	$ 49,000	$ -	$ -	$ 49,000	$ -	$ -	$ -	$ -	$ 49,000
47	1908	Buildings & Fixtures - HQ	$ 1,046,018	$ 5,000	$ -	$ 1,051,018	-$ 383,856	-$ 17,319	$ -	-$ 401,175	$ 649,843
47	1908	Buildings & Fixtures - PCB Shed	$ 8,690	$ -	$ -	$ 8,690	-$ 7,442	-$ 357	$ -	-$ 7,798	$ 892
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 216,633	$ 5,000	$ -	$ 221,633	-$ 179,597	-$ 8,428	$ -	-$ 188,025	$ 33,609
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equipment - Hardware	$ 414,902	$ 5,000	$ -	$ 419,902	-$ 371,008	-$ 22,511	$ -	-$ 393,519	$ 26,383
12	1925	Computer Software	$ 1,816,312	$ 190,000	$ -	$ 2,006,312	-$ 1,664,636	-$ 111,673	$ -	-$ 1,776,308	$ 230,004
12	1925	Computer Software (CIS TOU upgrade)	$ 170,000	$ -	$ -	$ 170,000	-$ 85,000	-$ 34,000	$ -	-$ 119,000	$ 51,000
10	1930	Transportation Equipment<3 tons	$ 159,405	$ -	$ -	$ 159,405	-$ 108,071	-$ 13,468	$ -	-$ 121,539	$ 37,866
10	1930	Transportation Equipment>3 tons	$ 940,581	$ -	$ -	$ 940,581	-$ 397,229	-$ 79,761	$ -	-$ 476,989	$ 463,592
10	1930	Transportation Equipment-trailer	$ 38,458	$ -	$ -	$ 38,458	-$ 38,458	$ -	$ -	-$ 38,458	$ -
10	1930	Transportation Equipment-old account				$ -				$ -	$ -
8	1935	Stores Equipment	$ 24,684	$ 5,000	$ -	$ 29,684	-$ 19,417	-$ 1,293	$ -	-$ 20,710	$ 8,974
8	1940	Tools, Shop & Garage Equipment	$ 466,555	$ 5,000	$ -	$ 471,555	-$ 424,524	-$ 15,302	$ -	-$ 439,826	$ 31,729
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 54,383	$ -	$ -	$ 54,383	-$ 42,436	-$ 3,991	$ -	-$ 46,427	$ 7,956
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -		$ -	$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 325,968	$ -	$ -	$ 325,968	-$ 266,814	-$ 31,797	$ -	-$ 298,610	$ 27,357
47	1980	System Supervisor Equipment - smartgrid	$ 237,952	$ -	$ -	$ 237,952	-$ 18,227	-$ 18,227	$ -	-$ 36,453	$ 201,499
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants - Poles	-$ 238,366	-$ 30,000	$ -	-$ 268,366	$ 66,591	$ 4,881	$ -	$ 71,472	-$ 196,894
47	1995	Contributions & Grants - Wires	-$ 235,221	-$ 5,000	$ -	-$ 240,221	$ 74,212	$ 3,149	$ -	$ 77,361	-$ 162,860
47	1995	Contributions & Grants - OH services	-$ 146,562	-$ 10,000	$ -	-$ 156,562	$ 50,831	$ 3,045	$ -	$ 53,876	-$ 102,686
47	1995	Contributions & Grants - Conduit	-$ 879,222	-$ 90,000	$ -	-$ 969,222	$ 213,956	$ 11,972	$ -	$ 225,928	-$ 743,294
47	1995	Contributions & Grants - UG conductor	-$ 1,788,778	-$ 120,000	$ -	-$ 1,908,778	$ 584,995	$ 34,014	$ -	$ 619,009	-$ 1,289,769
47	1995	Contributions & Grants - UG services	-$ 1,606,653	-$ 140,000	$ -	-$ 1,746,653	$ 432,278	$ 32,180	$ -	$ 464,458	-$ 1,282,194
47	1995	Contributions & Grants - Transformers	-$ 2,283,741	-$ 105,000	$ -	-$ 2,388,741	$ 671,793	$ 44,026	$ -	$ 715,819	-$ 1,672,923
47	1995	Contributions & Grants - Building	-$ 13,000	$ -	$ -	-$ 13,000	$ 3,585	$ 205	$ -	$ 3,790	-$ 9,210
47	1995	Contributions & Grants - Meters	-$ 7,344	$ -	$ -	-$ 7,344	$ 3,318	$ 294	$ -	$ 3,612	-$ 3,732
47	1995	Contributions & Grants - Trucks	-$ 9,722	$ -	$ -	-$ 9,722	$ 9,722	$ -	$ -	$ 9,722	$ 0
	etc.					$ -				$ -	$ -
						$ -				$ -	$ -
		Sub-Total	**$ 44,938,119**	**$ 1,285,000**	**-$ 477,000**	**$ 45,746,119**	**-$ 23,010,427**	**-$ 1,005,631**	**$ 447,000**	**-$ 23,569,057**	**$ 22,177,062**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 44,938,119**	**$ 1,285,000**	**-$ 477,000**	**$ 45,746,119**	**-$ 23,010,427**	**-$ 1,005,631**	**$ 447,000**	**-$ 23,569,057**	**$ 22,177,062**

10		Transportation
8		Stores Equipment

Less: Fully Allocated Depreciation	
Transportation	-$ 93,228
Stores Equipment	-$ 1,293
Net Depreciation	-$ 911,109

Appendix 6 – 7.3

Tables for Issue 7.3

Table 4.4.3 (updated)

CCA Continuity Schedule (2013)

Class	Class Description	UCC Prior Year Ending Balance	Additions	Dispositions	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 22-Feb-2005	10,092,052	0	0	10,092,052	0	10,092,052	4%	403,682	9,688,370
1b	Buildings	96,558	0	0	96,558	0	96,558	6%	5,793	90,765
2	Distribution System - pre 1988	3,349,969	0	0	3,349,969	0	3,349,969	6%	200,998	3,148,971
6	Buildings - after 1990	3,670	0	0	3,670	0	3,670	10%	367	3,303
8	General Office/Stores Equip	385,575	5,751	0	391,326	2,875	388,450	20%	77,690	313,636
10	Computer Hardware/ Vehicles	353,014	53,681	35,341	371,354	9,170	362,184	30%	108,655	262,699
10.1	Certain Automobiles		0	0	0	0	0	30%	0	0
12	Computer Software	57,669	104,895	0	162,564	52,448	110,117	100%	110,117	52,448
3	Buildings - pre 1990		0	0	0	0	0	5%	0	0
			0	0	0	0	0		0	0
13 3	Lease # 3		0	0	0	0	0		0	0
13 4	Lease # 4		0	0	0	0	0		0	0
14	Franchise		0	0	0	0	0		0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	25,277	0	0	25,277	0	25,277	8%	2,022	23,255
43.1	Certain Energy-Efficient Electrical Generating Equipment		0	0	0	0	0	30%	0	0
45	Computers & Systems Hardware acq'd post Mar 22/04	563	0	0	563	0	563	45%	253	310
50	Computers & Systems Hardware acq'd post Mar 19/07	16,642	38,762	0	55,404	19,381	36,023	55%	19,813	35,591
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)		0	0	0	0	0	30%	0	0
47	Distribution System - post 22-Feb-2005	9,501,812	1,357,079	425,970	10,432,921	465,554	9,967,366	8%	797,389	9,635,532
	SUB-TOTAL - UCC	23,882,801	1,560,167	461,310	24,981,658	549,429	24,432,230		1,726,780	23,254,878
CEC	Incorporation costs	10,564								
CEC	Land Rights									
CEC	FMV Bump-up									
	SUB-TOTAL - CEC	10,564								

Table 4.4.5 (updated)

CCA Continuity Schedule (2014)

Class	Class Description	UCC Prior Year Ending Balance	Additions	Dispositions	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 22-Feb-2005	9,688,370	0	0	9,688,370	0	9,688,370	4%	387,535	9,300,835
1b	Buildings	90,765	0	0	90,765	0	90,765	6%	5,446	85,319
2	Distribution System - pre 1988	3,148,971	0	0	3,148,971	0	3,148,971	6%	188,938	2,960,033
6	Buildings - after 1990	3,303	0	0	3,303	0	3,303	10%	330	2,973
8	General Office/Stores Equip	313,636	15,000	0	328,636	7,500	321,136	20%	64,227	264,409
10	Computer Hardware/ Vehicles	262,699	0	0	262,699	0	262,699	30%	78,810	183,889
10.1	Certain Automobiles	0	0	0	0	0	0	30%	0	0
12	Computer Software	52,448	190,000	0	242,448	95,000	147,448	100%	147,448	95,000
3	Buildings - pre 1990	0	0	0	0	0	0	5%	0	0
		0	0	0	0	0	0	0%	0	0
13 3	Lease # 3	0	0	0	0	0	0		0	0
13 4	Lease # 4	0	0	0	0	0	0		0	0
14	Franchise	0	0	0	0	0	0		0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	23,255	0	0	23,255	0	23,255	8%	1,860	21,394
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0	0	0	30%	0	0
45	Computers & Systems Hardware acq'd post Mar 22/04	310	0	0	310	0	310	45%	139	170
50	Computers & Systems Hardware acq'd post Mar 19/07	35,591	5,000	0	40,591	2,500	38,091	55%	20,950	19,641
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0	0	0	30%	0	0
47	Distribution System - post 22-Feb-2005	9,635,532	1,075,000	477,000	10,233,532	299,000	9,934,532	8%	794,763	9,438,769
	SUB-TOTAL - UCC	23,254,878	1,285,000	477,000	24,062,878	404,000	23,658,878		1,690,446	22,372,432
CEC	Goodwill	10,564								
CEC	Land Rights	0								
CEC	FMV Bump-up	0								
	SUB-TOTAL - CEC	10,564								

Appendix 6 – 7.5

Table for Issue 7.5

Table 5.1.3 – Actual Weighted Average Cost of Long-Term Debt - UPDATED

Weighted Debt Cost

Description	Debt Holder	Affliated with LDC?	Date of Issuance	Principal	Term (Years)	Rate%	Year Applied to	Actual/ Forecast Interest Cost
Pursuant to transfer by-law	Town of Niagara-on-the-Lake	Yes - shareholder	15-Jul-2008	$ 6,530,694	10 renewable	7.25%	2009	473,475
To finance construction of a transformer station	CIBC	No	1-Aug-2003	$ 1,822,288	15	6.03%	2009	109,884
To finance purchase of a transformer station from Hydro One	CIBC	No	31-Oct-2005	$ 2,122,867	15	5.38%	2009	114,210
Pursuant to transfer by-law	Town of Niagara-on-the-Lake	Yes - shareholder	15-Jul-2008	$ 6,213,381	10 renewable	7.25%	2010	450,470
To finance construction of a transformer station	CIBC	No	1-Aug-2003	$ 1,800,259	15	6.03%	2010	108,556
To finance purchase of a transformer station from Hydro One	CIBC	No	31-Oct-2005	$ 1,825,509	15	5.38%	2010	98,212
Pursuant to transfer by-law	Town of Niagara-on-the-Lake	Yes - shareholder	15-Jul-2008	$ 5,517,671	10 renewable	7.25%	2011	400,031
To finance construction of a transformer station	CIBC	No	1-Aug-2003	$ 1,606,392	15	6.03%	2011	96,865
To finance purchase of a transformer station from Hydro One	CIBC	No	31-Oct-2005	$ 1,708,821	15	5.38%	2011	91,935
To finance implementation of Smart Meters	Ontario Infrastructure Projects Corporation	No	15-Feb-2011	$ 1,334,945	15	4.27%	2011	57,002
Pursuant to transfer by-law	Town of Niagara-on-the-Lake	Yes - shareholder	15-Jul-2008	$ 4,788,235	10 renewable	7.25%	2012	347,147
To finance construction of a transformer station	CIBC	No	1-Aug-2003	$ 1,414,403	15	6.03%	2012	85,289
To finance purchase of a transformer station from Hydro One	CIBC	No	31-Oct-2005	$ 1,538,903	15	5.38%	2012	82,793
To finance implementation of Smart Meters	Ontario Infrastructure Projects Corporation	No	15-Feb-2011	$ 1,381,986	15	4.27%	2012	59,011
Pursuant to transfer by-law	Town of Niagara-on-the-Lake	Yes - shareholder	15-Jul-2008	$ 4,182,695	10 renewable	7.25%	2013	303,245
To finance construction of a transformer station	CIBC	No	1-Aug-2003	$ 1,229,451	15	6.03%	2013	74,136
To finance purchase of a transformer station from Hydro One	CIBC	No	31-Oct-2005	$ 1,418,465	15	5.38%	2013	76,313
To finance implementation of Smart Meters	Ontario Infrastructure Projects Corporation	No	15-Feb-2011	$ 1,266,986	15	4.27%	2013	54,100
2014 cash requirements	To be determined	No	1-Jan-2014	$ 300,000	10	3.18%	2014	9,540
Pursuant to transfer by-law	Town of Niagara-on-the-Lake	Yes - shareholder	15-Jul-2008	$ 3,461,956	10 renewable	4.88%	2014	168,943
To finance construction of a transformer station	CIBC	No	1-Aug-2003	$ 1,018,693	15	6.03%	2014	61,427
To finance purchase of a transformer station from Hydro One	CIBC	No	31-Oct-2005	$ 1,257,354	15	5.38%	2014	67,646
To finance implementation of Smart Meters	Ontario Infrastructure Projects Corporation	No	15-Feb-2011	$ 1,167,603	15	4.27%	2014	49,857
								0

2009 Total Long Term Debt	10,475,849	Total Interest Cost for 2009	697,570
		Weighted Debt Cost Rate for 2009	6.66%
2010 Total Long Term Debt	9,839,149	Total Interest Cost for 2010	657,238
		Weighted Debt Cost Rate for 2010	6.68%
2011 Total Long Term Debt	10,167,829	Total Interest Cost for 2011	645,833
		Weighted Debt Cost Rate for 2011	6.35%
2012 Total Long Term Debt	9,123,528	Total Interest Cost for 2012	574,239
		Weighted Debt Cost Rate for 2012	6.29%
2013 Total Long Term Debt	8,097,597	Total Interest Cost for 2013	507,795
		Weighted Debt Cost Rate for 2013	6.27%
2014 Total Long Term Debt	7,205,606	Total Interest Cost for 2014	357,413
		Weighted Debt Cost Rate for 2014	4.96%

Appendix 6 – 7.6

Table for Issue 7.6

Forecast of Other Revenues for 2014

USoA #	USoA Description	2009 Actual	2010 Actual	2011 Actual[2]	2012 Actual[2]	2013 actual		Test Year
						Exc 4305	Exc. Items not in Test*	2014
	Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
4080 (part) and 4086	SSS Administration Revenue	$ 27,935	$ 21,983	$ 22,984	$ 23,919	$ 24,567	$ 24,567	$ 25,579
4082	Retail Services Revenues	$ 8,531	$ 8,415	$ 7,816	$ 6,432	$ 5,696	$ 5,696	$ 8,017
4084	Service Transaction Requests Revenues	$ 107	$ 194	$ 153	$ 67	$ 41	$ 41	$ 151
4210	Rent from Electric Property	$ 70,070	$ 75,137	$ 75,070	$ 76,655	$ 77,447	$ 77,447	$ 79,100
4225	Late Payment Charges	$ 43,050	$ 41,139	$ 48,275	$ 44,532	$ 39,750	$ 39,750	$ 38,000
4235	Specific Service Charges	$ 47,754	$ 41,414	$ 47,203	$ 63,564	$ 98,309	$ 98,309	$ 76,330
4305	Regulatory Debits	$ -	$ -	$ -	$ -	$ -		$ -
4324	Special Purpose Charge Recovery	$ -	$ 42,302	$ -	$ 0	$ -	$ -	$ -
4325	Revenues from Merchandise, Jobbing, Etc.	$ 80,148	$ 49,533	$ 48,547	$ 52,664	$ 39,615	$ 39,615	$ 49,800
4340	Profits & Losses from Fin. Instr. Hedges	$ 139,806	$ 8,170	-$ 85,871	$ 118,201	$ 110,409		$ -
4355	Gain on Disposition of Property	$ 9,451	$ 6,064	$ 53,986	$ 49,000	$ 5,120	$ 5,120	$ -
4360	Loss on Disposition of Property	-$ 12,744	$ -	$ -	-$ 33,473	-$ 7,942	-$ 7,942	-$ 8,000
4375	Revenues from Non-Utility Operations	$ 219,129	$ 321,075	$ 381,059	$ 359,244	$ 304,116		$ -
4380	Expenses from Non-Utility Operations	-$ 269,597	-$ 302,003	-$ 364,732	-$ 291,177	-$ 327,826		$ -
4390	Miscellaneous Non-Operating Income	$ 21,249	$ 86,188	$ 20,287	$ 4,626	$ 6,432	$ 6,432	$ 6,900
4405	Interest and Dividend Income	$ 26,351	$ 42,921	$ 168,707	-$ 55,981	$ 14,157	$ 6,113	$ 7,000
Specific Service Charges		$ 47,754	$ 41,414	$ 47,203	$ 63,564	$ 98,309	$ 98,309	$ 76,330
Late Payment Charges		$ 43,050	$ 41,139	$ 48,275	$ 44,532	$ 39,750	$ 39,750	$ 38,000
Other Operating Revenues		$ 106,643	$ 105,729	$ 106,022	$ 107,073	$ 107,752	$ 107,752	$112,847
Other Income or Deductions		$ 213,793	$ 254,251	$ 221,984	$ 203,105	$ 144,082	$ 49,339	$ 55,700
Total		$ 411,240	$ 442,533	$ 423,485	$ 418,273	$ 389,893	$ 295,150	$282,877

Appendix 6 – 7.7

Table for Issue 7.7

Table 6.1.1 Revenue Sufficiency – Agreed

Niagara-on-the-Lake Hydro Inc.
, License Number ED-2002-0547, File Number EB-2013-0155

Niagara-on-the-Lake Hydro Inc.
Revenue Deficiency Determination

Description	2013 Bridge Actual	2014 Test Existing Rates	2014 Test - Required Revenue
Revenue			
Revenue Deficiency			(386,736)
Distribution Revenue	5,059,576	4,848,735	4,848,735
Other Operating Revenue (Net)	(396,410)	282,877	282,877
Total Revenue	**4,663,166**	**5,131,612**	**4,744,877**
Costs and Expenses			
OM&A	2,181,889	2,155,262	2,155,262
Depreciation & Amortization	985,790	911,109	911,109
Property Taxes	28,146	28,596	28,596
Return on PP&E			0
Deemed Interest	856,594	700,759	700,759
Total Costs and Expenses	**4,052,420**	**3,795,727**	**3,795,727**
Utility Income Before Income Taxes	**610,746**	**1,335,885**	**949,150**
Income Taxes:			
Corporate Income Taxes	3,502	92,414	32,470
Total Income Taxes	**3,502**	**92,414**	**32,470**
Utility Net Income	**607,244**	**1,243,471**	**916,679**
Income Tax Expense Calculation:			
Accounting Income	610,746	1,335,885	949,150
Tax Adjustments to Accounting Income	(542,990)	(662,245)	(662,245)
Taxable Income	**67,756**	**673,640**	**286,904**
Income tax expense before credits	**10,502**	**104,414**	**44,470**
Credits	**7,000**	**12,000**	**12,000**
Income Tax Expense	3,502	92,414	32,470
Tax Rate	15.50%	15.50%	15.50%
Actual Return on Rate Base:			
Rate Base	24,028,409	24,483,958	24,483,958
Interest Expense	856,594	700,759	700,759
Net Income	607,244	1,243,471	916,679
Total Actual Return on Rate Base	**1,463,838**	**1,944,230**	**1,617,439**
Actual Return on Rate Base	6.09%	7.94%	6.61%
Required Return on Rate Base:			
Rate Base	24,028,409	24,483,958	24,483,958
Return Rates:			
Return on Debt (Weighted)	5.94%	4.77%	4.77%
Return on Equity	8.01%	9.36%	9.36%
Deemed Interest Expense	856,594	700,759	700,759
Return On Equity	769,870	916,679	916,679
Total Return	**1,626,465**	**1,617,439**	**1,617,439**
Expected Return on Rate Base	6.77%	6.61%	6.61%
Revenue Deficiency After Tax	**162,626**	**(326,792)**	**0**

Appendix 6 – 8.2

Tables for Issue 8.2

Sheet I6.1 Revenue Worksheet - RUN 3 after Settlement

Total kWhs from Load Forecast	187,976,750
Total kWs from Load Forecast	204,554
Deficiency/sufficiency (RRWF 8. cell F51)	386,736
Miscellaneous Revenue (RRWF 5. cell F48)	282,877

			1	2	3	7	9
	ID	Total	Residential	General Service less than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Unmetered Scattered Load
Billing Data							
Forecast kWh	CEN	187,976,750	67,753,410	37,260,698	81,473,856	1,248,464	240,322
Forecast kW	CDEM	204,554	-	-	201,178	3,377	-
Forecast kW, included in CDEM, of customers receiving line transformer allowance		39,096	-	-	39,096	-	-
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-					
KWh excluding KWh from Wholesale Market Participants	CEN EWMP	187,976,750	67,753,410	37,260,698	81,473,856	1,248,464	240,322
Existing Monthly Charge			$18.31	$45.97	$328.41	$4.98	$54.31
Existing Distribution kWh Rate			$0.0129	$0.0138			$0.0163
Existing Distribution kW Rate					$2.5664	$19.4795	
Existing TOA Rate					$0.56		
Additional Charges							
Distribution Revenue from Rates		$4,870,629	$2,430,368	$1,226,488	$1,008,570	$187,134	$18,069
Transformer Ownership Allowance		$21,894	$0	$0	$21,894	$0	$0
Net Class Revenue	CREV	$4,848,735	$2,430,368	$1,226,488	$986,676	$187,134	$18,069

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Sheet I6.2 Customer Data Worksheet - RUN 3 after Settlement

			1	2	3	7	9
	ID	Total	Residential	General Service less than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Unmetered Scattered Load
Billing Data							
Bad Debt 3 Year Historical Average	BDHA	$18,040	$13,645	$4,395	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$44,649	$28,933	$9,228	$6,141	$302	$45
Number of Bills	CNB	102,314	85,000	15,494.67	1,499	60	261
Number of Devices			7,083	1,291	125	2,031	22
Number of Connections (Unmetered)	CCON	2,052				2,031	22
Total Number of Customers	CCA	8,526	7,083	1,291	125	5	22
Bulk Customer Base	CCB	-	-	-	-	-	-
Primary Customer Base	CCP	10,552	7,083	1,291	125	2,031	22
Line Transformer Customer Base	CCLT	10,543	7,083	1,291	116	2,031	22
Secondary Customer Base	CCS	9,359	6,587	700	19	2,031	22
Weighted - Services	CWCS	7,126	6,587	532	7	-	-
Weighted Meter -Capital	CWMC	2,536,052	1,876,684	490,736	168,631	-	-
Weighted Meter Reading	CWMR	10,769	7,083	1,291	2,269	125	-
Weighted Bills	CWNB	102,219	85,000	15,465	1,503	47	203

Bad Debt Data

Historic Year:	2010	9,729	5,691	4,037	-	-	-
Historic Year:	2011	15,867	15,544	324	-	-	-
Historic Year:	2012	28,523	19,699	8,824	-	-	-
Three-year average		**18,040**	**13,645**	**4,395**	**-**	**-**	**-**

Sheet I8 Demand Data Worksheet - RUN 3 after Settlement

This is an input sheet for demand allocators.

CP TEST RESULTS	4 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

Customer Classes		Total	1 Residential	2 General Service less than 50 kW	3 General Service 50 to 4,999 kW	7 Street Lighting	9 Unmetered Scattered Load
CO-INCIDENT PEAK							
1 CP							
Transformation CP	TCP1	39,315	12,701	9,614	16,975	-	25
Bulk Delivery CP	BCP1	39,315	12,701	9,614	16,975	-	25
Total Sytem CP	DCP1	39,315	12,701	9,614	16,975	-	25
4 CP							
Transformation CP	TCP4	147,456	44,057	41,082	62,216	-	102
Bulk Delivery CP	BCP4	147,456	44,057	41,082	62,216	-	102
Total Sytem CP	DCP4	147,456	44,057	41,082	62,216	-	102
12 CP							
Transformation CP	TCP12	365,122	121,933	92,154	149,441	1,273	322
Bulk Delivery CP	BCP12	365,122	121,933	92,154	149,441	1,273	322
Total Sytem CP	DCP12	365,122	121,933	92,154	149,441	1,273	322
NON CO_INCIDENT PEAK							
1 NCP							
Classification NCP from Load Data Provider	DNCP1	44,851	14,597	12,111	17,822	291	29
Primary NCP	PNCP1	44,851	14,597	12,111	17,822	291	29
Line Transformer NCP	LTNCP1	43,567	14,597	12,111	16,538	291	29
Secondary NCP	SNCP1	23,134	13,575	6,564	2,673	291	29
4 NCP							
Classification NCP from Load Data Provider	DNCP4	167,431	54,862	45,135	66,162	1,155	118
Primary NCP	PNCP4	167,431	54,862	45,135	66,162	1,155	118
Line Transformer NCP	LTNCP4	162,664	54,862	45,135	61,395	1,155	118
Secondary NCP	SNCP4	86,682	51,022	24,463	9,924	1,155	118
12 NCP							
Classification NCP from Load Data Provider	DNCP12	413,331	148,169	101,069	160,300	3,441	353
Primary NCP	PNCP12	413,331	148,169	101,069	160,300	3,441	353
Line Transformer NCP	LTNCP12	401,781	148,169	101,069	148,750	3,441	353
Secondary NCP	SNCP12	220,415	137,797	54,780	24,045	3,441	353

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Sheet O1 Revenue to Cost Summary Worksheet - RUN 3 after Settlement

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

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 General Service less than 50 kW	3 General Service 50 to 4,999 kW	7 Street Lighting	9 Unmetered Scattered Load
crev	Distribution Revenue at Existing Rates	$4,848,735	$2,430,368	$1,226,488	$986,676	$187,134	$18,069
mi	Miscellaneous Revenue (mi)	$282,877	$182,278	$48,468	$29,920	$21,792	$419
		Miscellaneous Revenue Input equals Output					
	Total Revenue at Existing Rates	$5,131,612	$2,612,647	$1,274,956	$1,016,596	$208,925	$18,488
	Factor required to recover deficiency (1 + D)	0.9202					
	Distribution Revenue at Status Quo Rates	$4,462,000	$2,236,522	$1,128,663	$907,979	$172,208	$16,628
	Miscellaneous Revenue (mi)	$282,877	$182,278	$48,468	$29,920	$21,792	$419
	Total Revenue at Status Quo Rates	$4,744,877	$2,418,800	$1,177,131	$937,899	$193,999	$17,047
	Expenses						
di	Distribution Costs (di)	$718,754	$402,331	$130,450	$116,283	$68,747	$942
cu	Customer Related Costs (cu)	$763,683	$589,663	$116,032	$33,742	$23,157	$1,087
ad	General and Administration (ad)	$701,422	$462,250	$118,216	$75,548	$44,459	$949
dep	Depreciation and Amortization (dep)	$911,109	$511,655	$176,747	$153,261	$68,452	$993
INPUT	PILs (INPUT)	$32,470	$17,286	$6,449	$6,162	$2,535	$38
INT	Interest	$700,759	$373,052	$139,190	$132,992	$54,703	$822
	Total Expenses	$3,828,197	$2,356,237	$687,086	$517,989	$262,054	$4,832
	Direct Allocation	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$916,679	$487,998	$182,078	$173,970	$71,559	$1,075
	Revenue Requirement (includes NI)	$4,744,877	$2,844,235	$869,164	$691,959	$333,612	$5,907
		Revenue Requirement Input equals Output					
	Rate Base Calculation						
	Net Assets						
dp	Distribution Plant - Gross	$46,723,687	$25,996,895	$8,783,951	$7,685,753	$4,198,237	$58,852
gp	General Plant - Gross	$6,077,041	$3,373,838	$1,154,331	$1,053,750	$488,017	$7,105
accum dep	Accumulated Depreciation	($23,289,742)	($12,810,650)	($4,400,094)	($3,755,277)	($2,292,313)	($31,408)
co	Capital Contribution	($7,458,609)	($4,777,463)	($1,174,305)	($829,894)	($668,252)	($8,695)
	Total Net Plant	$22,052,377	$11,782,620	$4,363,883	$4,154,332	$1,725,689	$25,853
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0
	Allocated Depreciation	*$37,808*	*$25,176.85*	*$6,313.91*	*$3,905.28*	*$2,360.81*	*$51.57*
COP	Cost of Power (COP)	$19,959,228	$7,220,282	$3,946,869	$8,617,826	$148,654	$25,597
	OM&A Expenses exc allocated depreciation	$2,146,050	$1,429,067	$358,385	$221,668	$134,003	$2,927
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0
	Subtotal	*$22,105,278*	*$8,649,349*	*$4,305,254*	*$8,839,495*	*$282,656*	*$28,524*
	Working Capital	$2,431,581	$951,428	$473,578	$972,344	$31,092	$3,138
	Total Rate Base	$24,483,958	$12,734,049	$4,837,461	$5,126,676	$1,756,781	$28,991
		Rate Base Input equals Output					
	Equity Component of Rate Base	$9,793,583	$5,093,619	$1,934,984	$2,050,671	$702,712	$11,596
	Net Income on Allocated Assets	$916,679	$62,563	$490,046	$419,910	($68,054)	$12,215
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0
	Net Income	$916,679	$62,563	$490,046	$419,910	($68,054)	$12,215
	RATIOS ANALYSIS						
	REVENUE TO EXPENSES STATUS QUO%	100.00%	85.04%	135.43%	135.54%	58.15%	288.59%
	EXISTING REVENUE MINUS ALLOCATED COSTS	$386,736	($231,588)	$405,793	$324,637	($124,687)	$12,581
		Deficiency Input equals Output					
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	($425,435)	$307,968	$245,940	($139,613)	$11,140
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.36%	1.23%	25.33%	20.48%	-9.68%	105.33%

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Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - RUN 3 after Settlement

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	7	9
	Residential	General Service less than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Unmetered Scattered Load
Customer Unit Cost per month - Avoided Cost	$8.31	$9.43	$29.04	$0.92	$3.81
Customer Unit Cost per month - Directly Related	$11.65	$13.14	$41.50	$1.38	$5.69
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$25.51	$24.44	$49.88	$13.66	$16.86
Existing Approved Fixed Charge	$18.31	$45.97	$328.41	$4.98	$54.31