Energy+

CAMBRIDGE AND NORTH DUMFRIES HYDRO INC.
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April 2, 2014

Ms. Kirsten Walli, Board Secretary
Ontario Energy Board
2300 Yonge Street,
Suite 2700, P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Cambridge and North Dumfries Hydro Inc., 2014 Electricity Distribution Rate Application, Settlement Proposal, Board File No. EB-2013-0116

Cambridge and North Dumfries Hydro Inc. ("CND") is pleased to submit the enclosed Settlement Proposal pursuant to the Settlement Conference held on March 6 -7, 2014 in accordance with Procedural Order No. 2 in the above noted proceeding. An extension for of the filing of the Settlement Proposal to April 3, 2014 was granted by the Board by way of letter dated March 28, 2014.

CND is pleased to advise that the parties have achieved a partial settlement in this matter. As is more fully detailed in the attached Settlement Proposal, the following issues remain unsettled:

i) **OM&A.** The parties are not in agreement that the Applicant's proposed OM&A costs for the test year are appropriate.

ii) **Cost of Capital – Long Term Debt Component.** The Parties are not in agreement that the Applicant's proposed long term debt in the test year is appropriate.

iii) **Other Revenues – Interest Component.** The Parties are not in agreement that the Applicant's proposed interest revenues for the test year are appropriate.

iv) **Rate Design – GS 50 to 999 Fixed/Variable Split.** The Parties are not in agreement that the Applicant's proposed fixed and variable split for the GS 50 to 999 rate class is appropriate.

v) **Removal Costs.** The Parties are not in agreement on the proper accounting treatment of removal costs in the test year. The Parties are also not in agreement on the inclusion of removal costs in account 1576 over the historical period.

CND understands that unsettled matters will be the subject of an oral hearing.

Respectfully submitted,

Grant Brooker, CPA, CA
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EB-2013-0116

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 Cambridge and North Dumfries Hydro Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2014.

CAMBRIDGE AND NORTH DUMFRIES HYDRO INC.

SETTLEMENT PROPOSAL

April 2, 2014

Cambridge and North Dumfries Hydro Inc.

EB-2013-0116

Settlement Proposal

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Cambridge and North Dumfries Hydro Inc.

EB-2013-0116

Settlement Proposal

Filed with OEB: April 2, 2014

Cambridge and North Dumfries Hydro Inc. (the "Applicant" or "CND") filed an application with the Ontario Energy Board (the "Board") on October 1, 2013, as updated on October 28, 2013 under section 78 of the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, (Schedule B) (the "Act"), seeking approval for changes to the rates that CND charges for electricity distribution, to be effective May 1, 2014 (Board Docket Number EB-2013-0116) (the "Application").

The Board issued a Notice of Application and Hearing dated November 12, 2013 and Procedural Order No. 1 on December 16, 2013, the latter of which included a draft issues list and sought submissions on the same. On January 17, 2014, the Board issued Procedural Order No. 2, in which the Board established an approved issues list, set dates for the filing of interrogatories and responses, and made provision for a settlement conference.

CND filed its interrogatory responses with the Board on February 25, 2014, pursuant to which CND asked the Board to hold the financial statements of CND's two competitive affiliates in confidence. The Board issued Procedural Order No. 3 on February 27, 2014 seeking submissions from any parties or Board staff if they wish to object to CND's confidentiality claim. As an interim measure, the Board provided for confidential treatment of the documents. No parties objected to CND's confidentiality request. The relevant documents continue to be the subject of the Board's interim confidentiality measures.

This Settlement Proposal is filed with the Board in connection with the Application.

Further to the Board's Procedural Order No. 2, a settlement conference was convened on March 6, 2014 and continued to March 7, 2014 in accordance with the Board's *Rules of Practice and Procedure* (the "Rules") and the Board's *Settlement Conference Guidelines* (the "Guidelines"). Ms. Emay Cowx acted as facilitator for the settlement conference which lasted for two days.

CND and the following intervenors (the "Intervenors"), participated in the settlement conference:

Energy Probe ("EP");
School Energy Coalition ("SEC"); and
Vulnerable Energy Consumers Coalition ("VECC").

CND and the Intervenors are collectively referred to below as the "Parties".

Ontario Energy Board staff ("Board staff") also participated in the settlement conference. The role adopted by Board staff is set out in page 5 of the Guidelines. Although Board staff is not a party to this Settlement Proposal, as noted in the Guidelines, Board staff who did participate in the settlement conference are bound by the same confidentiality requirements that apply to the Parties to the proceeding.

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 and 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, as applicable, together with references to the evidence. The Parties agree that references to the "evidence" in this Settlement Proposal shall, unless the context otherwise requires, include (a) additional information included by the Parties in this Settlement Proposal, and (b) the Appendices to this document. The supporting Parties for each settled and partially settled issue, as applicable, agree that the evidence in respect of that settled or partially settled issue, as applicable, is sufficient in the context of the overall settlement to support the proposed 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 Parties acknowledge that the Appendices were prepared by CND. While the Intervenors have reviewed the Appendices, the Intervenors are relying on the accuracy of the underlying evidence in entering into this Settlement Proposal.

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 Parties are pleased to advise the Board that they have reached a partial agreement with respect to the settlement of some of the issues in this proceeding. Specifically:

"Complete Settlement" means an issue for which complete settlement was reached by all Parties, and if this Settlement Proposal is accepted by the Board, the Parties will not adduce any	# issues settled:

evidence or argument during the oral hearing in respect of these issues.	**7**
"Partial Settlement" means an issue for which there is partial settlement, as CND and the Intervenors who take any position on the issue were able to agree on some, but not all, aspects of the particular issue. If this Settlement Proposal is accepted by the Board, the Parties who take any position on the issue will only adduce evidence and argument during the hearing on those portions of the issues not addressed in this Settlement Proposal.	# issues partially settled: **8**
"No Settlement" means an issue for which no settlement was reached. CND and the Intervenors who take a position on the issue will adduce evidence and/or argument at the hearing on the issue.	# issues not settled: **10**

If applicable, a Party who is noted as taking no position on an issue may or may not have participated in the discussion on that particular issue, but in either case such Party takes no position a) on the settlement reached, and b) on the sufficiency of the evidence filed to date.

According to the 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. Because this is a partial settlement of some issues, to the extent that issues are interrelated a number of the resulting settled or partially settled issues require further adjustment after the Board's decision. These adjustments are specifically set out in the text of the Settlement Proposal.

The Parties have settled the issues as a package, and none of the parts of this Settlement Proposal are severable. If the Board does not accept this Settlement Proposal in its entirety, then there is no settlement (unless the Parties agree in writing that any part(s) of this Settlement Proposal that the Board does accept may continue as a valid settlement without inclusion of any part(s) that the Board does not accept).

In the event that the Board directs the Parties to make reasonable efforts to revise the Settlement Proposal, the Parties agree to use reasonable efforts to discuss any potential revisions, but no Party will be obligated to accept any proposed revision. The Parties agree that all of the Parties who took on a position on a particular issue must agree with any revised Settlement Proposal as it relates to that issue prior to its resubmission to the Board.

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 CND is a party to such proceeding.

SUMMARY

In reaching this partial settlement, the Parties have been guided by the Filing Requirements for 2014, the approved issues list, and the Report of the Board titled *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* dated October 18, 2012 ("RRFE").

The Parties recognize the Application is among the first to be filed under the RRFE. The Parties further recognize that this is a transition year. The Parties have taken these facts into consideration when developing this Settlement Proposal.

This Settlement Proposal reflects a partial settlement of the issues in this proceeding. The Parties believe that, if accepted by the Board as the Parties request, this Settlement Proposal will narrow the scope of issues to be heard during an oral hearing. The following is a description of the key areas of disagreement among the Parties that would go to oral hearing if this Settlement Proposal is accepted:

1. **OM&A (Issues 1.1, 1.2, 2.1, 3.1, 4.1, 4.2, 4.3, 5.1, 6.1, 6.2, 7.1, 7.4, 7.7 and 8.6):** The Parties are not in agreement that the Applicant's proposed OM&A costs for the test year are appropriate.

2. **Cost of Capital - Long Term Debt Component (Issue 7.5):** The Parties are not in agreement that the Applicant's proposed long term debt cost in the test year is appropriate.

3. **Other Revenues – Interest Component (Issue 7.6):** The Parties are not in agreement that the Applicant's proposed interest revenues for the test year are appropriate.

4. **Rate Design – GS 50 to 999 kW Fixed/Variable Split (Issue 8.3):** The Parties are not in agreement that the Applicant's proposed fixed and variable split for the GS 50 to 999 kW rate class is appropriate.

5. **Removal Costs (Issues 7.1, 7.2, 9.1 and 9.2):** The Parties are not in agreement on the proper accounting treatment of removal costs in the test year. The Parties are also not in agreement on the inclusion of removal costs in account 1576 over the historic period.

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.

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?

Partial Settlement: For the purposes of the partial settlement of the issues in this proceeding, the Parties agree that, subject to the changes agreed to by the Parties and set out in this Settlement Proposal, the regional and infrastructure investment planning undertaken by the Applicant and outlined in the Application support the appropriate management of the Applicant's assets in the test year from a regional and infrastructure investment perspective only.

Because the Parties are not in agreement that the Applicant's proposed OM&A and long term debt costs for the test year are appropriate, the Parties do not agree that the Applicant's asset management planning as outlined in the Application support the appropriate management of the Applicant's assets.

Evidence: Exhibit 1/Tab 4/Schedule 1; Exhibit 1/Tab 8/Schedule 5; Exhibit 1/ Appendix 1-2 – Corporate Communication Strategy**,** Exhibit 1/Appendix 1-6A – Strategic Plan; Exhibit 1/Appendix 1-6B – IT Strategic Plan; Exhibit 1/Appendix 1-10 – Human Resources/Governance/Nominating Committee Mandate; Exhibit 2/Tab 2, Schedule 1/Pages 1 – 6; Exhibit 2/Appendix 2-8A – Distribution System Plan; Exhibit 4/Tab 1/Schedule 1; Exhibit 4/Tab 4/Schedule 2; Exhibit 4/Appendix 4-7 - Total Compensation Philosophy;

Interrogatories: 1.1-Staff-1; 1.1-SEC-1; 1.1-SEC-3; 1.1-SEC-5; 2.1-Staff-4; 4.1-Staff-9; and 4.1-VECC-6

Please refer to Appendices A to C to this document for the agreed upon Capital Additions for 2014.

Supporting parties: CND, EP, SEC and VECC.

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

No Settlement: Because the Parties are not in agreement that the Applicant's proposed OM&A costs for the test year are appropriate, the Parties also do not agree that the customer engagement activities 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?

No Settlement: Because the Parties are not in agreement that the Applicant's proposed OM&A costs for the test year are appropriate, the Parties also do not agree that 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.

3. Customer Focus

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

No Settlement: Because the Parties are not in agreement that the Applicant's proposed OM&A costs for the test year are appropriate, the Parties also do not agree that the Applicant's proposed capital expenditures and operating expenses are appropriately reflective of customer feedback and preferences.

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 level of associated revenue requirement requested by the applicant?

No Settlement: Because the Parties are not in agreement that the Applicant's proposed OM&A costs for the test year are appropriate, the Parties also do not agree that the Applicant's distribution system plan appropriately supports continuous improvement in productivity, the attainment of system reliability and quality objectives, and the level of associated revenue requirement requested by the Applicant.

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

No Settlement: Because the Parties are not in agreement that the Applicant's proposed OM&A costs for the test year are appropriate, the Parties also do not agree that the Applicant's proposed OM&A expenses are clearly driven by appropriate objectives and they show continuous improvement in cost performance.

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?

Partial Settlement: For the purposes of the partial settlement of the issues in this proceeding and with the intent of narrowing the scope of issues that will be heard at the oral phase of this proceeding, the Parties agree that the Applicant's proposed capital expenditures in the 2014 test year are, subject to the changes agreed to by the Parties and set out in this Settlement Proposal, appropriately paced and prioritized to result in reasonable rate increases for customers. As noted in respect of issue 7.1 below, CND has agreed to adjust its test year capital plan to reflect the deferral of $2.6M of projects. CND currently believes that [$2.6M] of lower priority System Renewal and System Service projects can be deferred mostly to 2015 (with a few to 2016) to achieve this reduction. This delay in timing for the identified projects is reasonable and will not, in CND's reasonable expectation, unduly affect distribution system safety or performance. The Parties recognize that individual projects may be adjusted by CND as priorities unfold between 2014-2019.

Please refer to Appendices A to C to this document for the agreed upon Capital Additions for 2014.

The Parties are not in agreement on the proper accounting treatment of removal costs in the test year. If CND's accounting treatment of expensing removal costs is not accepted by the Board, the Parties agree that CND will adjust the computation of rate base as follows:

1. Add the amounts of $333,253, $639,000, and $806,208 to capital additions for the years 2012, 2013, and 2014 respectively; and

2. Re-compute depreciation expense for each of the years 2012, 2013, and the 2014 Test Year.

Because the Parties are not in agreement that the Applicant's proposed OM&A costs for the test year are appropriate, the Parties also do not agree that the Applicant's proposed operating expenses are appropriately paced and prioritized to result in reasonable rate increases for customers or whether any additional rate mitigation is required.

Evidence: Exhibit 1/Tab 4/Schedule 1/Page 14; Exhibit 1/Tab 8/Schedule 3; Exhibit 2/Tab 2/Schedule 1; Exhibit 2/Appendix 2-6 – Appendix 2-BA Fixed Asset Continuity Schedule – 2014; Exhibit 2/Appendix 2-8A – Distribution System Plan; Exhibit 2/Appendix 2-8B – Capital Expenditure Table ; Exhibit 2/Appendix 2-10 – Capital Projects Table; Exhibit 8/Tab 1/Schedules 12and 13; Exhibit 8/Appendix 8-5 – Appendix 2-W (Bill Impacts)

Interrogatories: 1.1-Staff-1, 1.1-SEC-1, 1.1-SEC-2, 1.1-SEC-4, 1.1-SEC-5; 4.3-Staff-18, 4.3-SEC-31; 4.3-SEC-32;4.3-SEC-35; 4.3-SEC-37; 4.3-VECC-15; 4.3-VECC-16; 4.3-VECC-17; and 4.3-VECC-18

Supporting parties: CND, EP, SEC and VECC.

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?

Partial Settlement: For the purposes of the partial settlement of the issues in this proceeding and with the intent of narrowing the scope of issues that will be heard at the oral phase of this proceeding, the Parties agree that the Applicant is proposing to meet all obligations mandated by government relevant to this Application in the test year, including in respect of renewable energy, smart meters and any other obligations that are mandated as a condition of CND's distribution licence.

Because the Parties are not in agreement that the Applicant's proposed OM&A costs for the test year are appropriate, the Parties do not agree on the amount of the Applicant's proposed operating expenses that are required to meet the obligations mandated by government relevant to this Application in the test year, including in respect of renewable energy, smart meters and any other obligations that are mandated as a condition of CND's distribution licence.

Evidence: Exhibit 1/Tab 4/Schedule 1; Exhibit 2/Tab 2/Schedule 1; Exhibit 2/Appendix 2-8A – Distribution System Plan; Exhibit 4/Tab 1/Schedule 1/Page 3;

Interrogatories: 1.1-SEC-3; 2.1-Staff-5; 5.1-EP-17; 5.1-VECC-19; and 5.1-VECC-20.

Supporting parties: CND, EP, SEC and VECC.

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?

No Settlement: Because the Parties are not in agreement on several matters which are an input into the derivation of proposed rates, the Parties also do not agree that the Applicant's proposed rates allow it to meet its obligations to its customers while maintaining its financial viability. CND has provided a partial list of such obligations in response to IR 5.1-Energy Probe-17.

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

No Settlement: Because the Parties are not in agreement that the Applicant's proposed OM&A costs for the test year are appropriate, the Parties also do not agree that the Applicant has adequately demonstrated that the savings, if any, resulting from its operational effectiveness initiatives are sustainable.

7. Revenue Requirement

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

Complete Settlement: For the purposes of partial settlement of the issues in this proceeding, CND agrees to adjust its test year capital plan to reflect the deferral of $2.6M of projects, and subject to this adjustment the Parties agree that the newly proposed test year capital expenditures are reasonable.

As indicated in Appendix A below, the test year capital plan agreed to by the Parties is $15,049,383, determined by reducing the original proposed capital plan of $17,649,383 by $2,600,000. The associated depreciation is reduced from $4,989,877 to $4,959,263; a reduction of $30,614.

Please refer to Appendices A to C to this document for the agreed upon Capital Additions for 2014.

Appendix A – Amended Net Book Value of Fixed Assets;

Appendix B – Amended Appendix 2-BA Fixed Asset Continuity Schedule 2014; and

Appendix C – Amended Appendix 2-AB Capital Expenditure Summary 2009 through 2018.

If CND's accounting treatment of expensing removal costs is not accepted by the Board, the Parties agree that CND will adjust the computation of rate base as follows:

1. Add the amounts of $333,253, $639,000 and $806,208 to capital additions for the years 2012, 2013 and 2014 Test Year;

2. Re-compute depreciation expense for each of the years 2012, 2013, and the 2014 Test Year; and

3. Re-compute the 2014 rate base to incorporate the changes in capital additions and depreciation for each of the years 2012, 2013, and 2014.

Each of the above noted Appendices would be revised accordingly.

CND has agreed to adjust its working capital calculation to remove the fully allocated depreciation expense related to transportation cost (7.1-EP-23). For the purposes of the partial settlement of the issues in this proceeding, and subject to the adjustments noted in this paragraph, the Parties agree that the proposed working capital allowance of 13% is reasonable. In the absence of a lead-lag study, and given that CND has not implemented monthly billing of all customers (4.2-EP-12), the Parties agreed that the working capital allowance specified in the Filing Requirements for 2014 is appropriate for the purposes of achieving a partial settlement of the issues in this proceeding. The Parties agree that the calculation of working capital should be adjusted to reflect any changes in OM&A or cost of power that arise from this Settlement Proposal and from the hearing.

Subject to any adjustments to rate base required arising from the resolution of issue 9.2 and the adjustments noted in respect of this issue 7.1, for the purposes of partial settlement of the issues in this proceeding the Parties agree that the proposed test year rate base is reasonable.

Evidence: Exhibit 1/Tab 4/Schedule 1; Exhibit 2

Interrogatories: 1.1-Staff-1; 1.1-SEC-5; 4.1-Staff-9; 4.1-Staff-11; 4.1-Staff-12; 4.1-Staff-13; 4.1-Staff-14; 4.1-SEC-18; 7.1-EP-21; 7.1-EP-22; 7.1-EP-24; 7.1-EP-25; and 7.1-SEC-41 .

Supporting parties: CND, EP, SEC and VECC.

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?

Complete Settlement: Subject to any adjustments to depreciation/amortization expense required arising from the resolution of issue 9.2 for the purposes of partial settlement of the issues in this proceeding the Parties agree that the proposed levels of depreciation/amortization expense appropriately reflect the useful lives of the assets and the Board`s accounting policies.

Evidence: Exhibit 2/Tab 1/Schedule 2; Exhibit 2/Appendices 2-1 to 2-6 ; Exhibit 4/Tab 1/Schedule 1; Exhibit 4/Tab 7/Schedule 1 ; Exhibit 4/Tab 7/Schedule 2; Exhibit 4/Tab 7/Schedule 3; Exhibit 4/Appendix 4-15 – Kinetrics Useful Lives; Exhibit 4/Appendix 4-16 – Service Life Comparison; Exhibit 4/Appendix 4-17 to 4-20 – 2-C Depreciation and Amortization Expense

Interrogatories: 7.1-Energy Probe-22, 7.1-Energy Probe-23

Supporting parties: CND, EP, SEC and VECC.

7.3 Are the proposed levels of taxes appropriate?

Complete Settlement: CND has agreed to adjust its capital cost allowance treatment of computer hardware by moving it from class 10 to class 50. For the purposes of settlement of the issues in this proceeding, and subject to this adjustment, the Parties agree that the proposed levels of taxes are appropriate. The Parties agree that the proposed level of taxes will need to be reviewed at the draft rate order stage, to determine whether any updates are required based on the resolution of issues to be heard by the Board.

The amount of the tax expense built into the revenue requirement at this time is not material, primarily because the Capital Cost Allowance used for tax calculation purposes greatly exceeds the amortization used for the determination of accounting income. As indicated above, the Parties agree that the proposed level of taxes will need to be reviewed at the draft rate order stage, to determine whether any updates are required based on the resolution of issues to be heard by the Board.

Evidence: Exhibit 4/Tab 8/Schedule 1; Exhibit 4/Tab 8/Schedule 3; Exhibit 4/Appendix 4-21 – 2012 Corporate Tax Return; and Exhibit 4/Appendix 4-22 .

Supporting parties: CND, EP, SEC and VECC.

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

No Settlement: Because the Parties are not in agreement that the Applicant's proposed OM&A costs for the test year are appropriate, the Parties also do not agree that the proposed allocation of shared services and corporate costs are appropriate.

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

Partial Settlement: For the purposes of partial settlement of the issues in this proceeding, the Parties agree that the proposed capital structure, rate of return on equity and short term debt costs for the test year are appropriate. However, the Parties are not in agreement that the Applicant's proposed long term debt cost in the test year is appropriate.

		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$74,176,763	4.96%	$3,682,618
2	Short-term Debt	4.00%	$5,298,340	2.07%	$109,676
3	**Total Debt**	60.00%	$79,475,103	4.77%	$3,792,294
	Equity				
4	Common Equity	40.00%	$52,983,402	8.98%	$4,757,910
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$52,983,402	8.98%	$4,757,910
7	**Total**	100.00%	$132,458,506	6.46%	$8,550,203

		Interrogatory Responses			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$73,765,320	4.96%	$3,655,571
2	Short-term Debt	4.00%	$5,268,951	2.11%	$111,175
3	**Total Debt**	60.00%	$79,034,271	4.77%	$3,766,746
	Equity				
4	Common Equity	40.00%	$52,689,514	9.36%	$4,931,739
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$52,689,514	9.36%	$4,931,739
7	**Total**	100.00%	$131,723,785	6.60%	$8,698,484

Evidence: Exhibit 1/Tab 4/Schedule 1/Pages 25-26; and Exhibit 5

Interrogatories: 7.5-Staff-19 to 21; 7.5-Energy Probe-29 and 30.

Supporting parties: CND, EP, SEC and VECC.

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

Partial Settlement: For the purposes of partial settlement of the issues in this proceeding, and subject to the treatment of interest revenues, the Parties agree that subject to an increase to the forecast of other revenues of $54,000 in the test year, the other revenues forecast is appropriate. This increase is due to two causes: (i) $23,000 is to account for the gain on the disposition of vehicles in the test year (7.3-EP-32(b)); and (ii) $31,000 is based on an updated forecast for account 4390 (which includes sale of scrap) based on the historic average of 2010-2013 amounts. A summary is included in the table below.

Other Revenue, As Filed		$1,299,379
Add: Gain on Disposition of Vehicles		$23,000
Add: Misc. Non-Operating Income (Account 4390)		$31,000
Other Revenue, as per Settlement		$1,353,379

A detailed schedule of the updated Other Revenue is included as Appendix D to this document.

The Parties are not in agreement that the Applicant's proposed interest income (account 4405 – Interest and Dividend Income) for the test year is appropriate.

Evidence: Exhibit 3/Tab 4/Schedule 1

Interrogatories: 7.6-EP-31; 7.6-Energy Probe-32; and 7.6-VECC-35

Supporting parties: CND, EP, SEC and VECC.

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?

No Settlement: Because the Parties are not in agreement on several matters which are an input into the derivation of proposed rates (including operating expenses, return on capital, and interest revenues), the Parties also do not agree that the proposed revenue requirement has been accurately determined.

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?

Complete Settlement: The Parties agree to the following adjustments to the proposed load forecast:

(i) The 2014 power purchased load forecast will be 1,552.4 GWh which translates into billed level of 1,519.9 GWh after the adjustment for CDM. This forecast reflects the power purchased forecast of 1,524.6 GWh and billed level of 1,492.9 GWh, proposed by CND after the completion of the interrogatories, adjusted to include actual and not forecasted, 2013 regional employment and unemployment values. For 2014, the monthly regional employment and unemployment values were held constant at the December 2013 level.

(ii) For the General Service 50 to 999 kW customers and the Embedded Distributors the kW/kWh factor used to convert forecasted billed kWh to kW will be 0.3230% and 0.2368%, respectively. Based on the response to 8.1-Energy Probe-35 d), these factors are based on a statistically significant trend variable (at a 95% confidence level).

(iii) The proposed customer forecast and the proposed CDM adjustment are appropriate without change. Please refer to Issue 9.1 where the LRAMVA adjustments by class are provided.

For the purposes of settlement of the issues in this proceeding, and subject to the adjustments noted herein, the Parties agree that the proposed load forecast, including billing determinants, is an appropriate forecast of the energy and demand requirements of the applicant in the test year.

A revised Load Forecast Model in a live excel spreadsheet is included in this submission, which includes an updated Appendix 2-I LF_CDM_WF.

A summary of the settled load forecast is in provided in Appendix E.

Evidence: Exhibit 3, Tab 3,; Exhibit 3/Appendix 3-1 – Load Forecast (Regression) Model inputs; Exhibit 3,Appendix 3-2 – Load Forecast Model results; Exhibit3, Appendix 3-4 – Appendix 2-I (Load Forecast CDM Adjustment Workform).

Interrogatories: 8.1-Staff-24 and 25; 8.1-EP-34 to 39; and 8.1-VECC-36 to 42

Supporting parties: CND, EP, SEC and VECC.

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

Complete Settlement: For the purposes of settlement of the issues in this proceeding, CND is proposing for the test year to adjust the revenue-to-cost ratio of the street lighting class to 70%, and to use any excess revenues to reduce the revenue-to-cost ratio of the class with the highest revenue to cost ratio (USL) until the earlier of: (i) when revenue neutrality is achieved; or (ii) its revenue-to-cost ratio matches the revenue-to-cost ratio of the class with the next highest revenue to cost ratio (GS>50), in which case CND will continue to reduce the revenue-to-cost ratio of both classes in step until revenue neutrality is achieved.

For the purposes of settlement of the issues in this proceeding, the Parties agree to the following changes to the cost allocation methodology used for the two embedded distributors (the intent of which is to arrive at a more reasonable and accurate cost allocation for these customers), which will be based on using the direct allocation feature in the cost allocation model using the following steps:

1. The information provided in Tables Table 8-11 Proposed 2014 Embedded Distribution Low Voltage Charges – Waterloo North Hydro and Table 8-12 Proposed 2014 Embedded Distribution Low Voltage Charges – Hydro One Networks Inc. of the Application will be entered into tab I9 -Direct Allocation of the cost allocation model. In addition, cell C148 in tab I9 – Direct Allocation will be corrected to reference the total net fixed assets excluding general plant in tab I4 BO ASSETS.

2. In Tab I5.2 - Weighting Factors of the cost allocation model used in the application, the weighting factor for billing and collecting have been included for the two embedded distributors.

3. In tab I6.2 - Customer Data of the cost allocation model used in the application, the billing data reflects the number of annual bills sent to the two embedded distributor by CND.

4. In tab I6.2 - Customer Data and tab I8 - Demand Data the number of customers and the demand value will be set to zero to ensure cost of services not used by the two embedded distributors are not allocated to them.

5. In tab I7.1 - Meter Capital and tab I7.2 Meter Reading appropriate meter data will be included in these tabs for Hydro One to allocate meter cost to this embedded distributor. However, this will not be the case for Waterloo North Hydro since they own the meter and units used for billing are provided on the IESO invoice resulting in CND not incurring any meter reading costs for Waterloo North Hydro.

6. The specific cost allocation applicable to the embedded distributor class applying the above steps, will be determined on a final basis when all issues, but in particular the OM&A test year amount, are determined.

For the purposes of partial settlement of the issues in this proceeding, and subject to the adjustments noted above, the Parties agree that the cost allocation methodology is appropriate and results in revenue-to-cost ratios that are within the Board's permitted ranges. Final cost-to revenue ratios will be calculated when all issues, but in particular the OM&A test year amount, are determined.

Evidence: Exhibit 7; Exhibit 7/Appendix 7-1 – 2014 Cost Allocation Study; Exhibit 7/Appendix 7-2 – Appendix 2-P (Cost Allocation).

Interrogatories: 8.2-Staff-26 to 29; 8.2-Energy Probe-40 and 41; 8.2-VECC-43 and 44

Supporting parties: CND, EP, SEC and VECC.

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

Partial Settlement: For the purposes of partial settlement of the issues in this proceeding, and with the exception of the GS 50 – 999kW class, the Parties agree that the proposed rate design including class-specific fixed and variable splits and any applicant-specific rate classes are appropriate.

The Parties are not in agreement that the Applicant's proposed fixed and variable split for the GS 50 to 999 kW rate class is appropriate

Evidence: Exhibit 8/Tab 1/Schedules 1 and 2.

Interrogatories: 8.3-Energy Probe-42

Please see Appendix F to this document for the settled and partially settled class-specific fixed and variable splits.

Supporting parties: CND, EP, SEC and VECC.

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

Complete Settlement: For the purposes of partial settlement of the issues in this proceeding, the Parties agree that the proposed Total Loss Adjustment Factor of 3.35%, which is based on the average wholesale and retail kWh for the years 2008 to 2012, is appropriate for the distributor's system and is a reasonable proxy for the expected losses.

Evidence: Exhibit 8/Tab 1/Schedule 9 ; Exhibit 8/Appendix 8-3 – Appendix 2-R (Loss Factors).

Interrogatories: 8.4-Staff-30

Please see Appendix G to this document for the agreed upon Loss Adjustment Factors.

Supporting parties: CND, EP, SEC and VECC.

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

Complete Settlement: For the purposes of partial settlement of the issues in this proceeding, the Parties agree that the proposed forecast of other regulated rates and charges including the proposed Retail Transmission Service Rates are appropriate. The RTSR workform has been updated to reflect the Board-approved 2014 Uniform Transmission Rates and Sub-Transmission Rate for Hydro One Network Inc.

Evidence: Exhibit 8/Tab 1/Schedule 3; Exhibit 8/Appendix 8-1 – RTSR Workform;

Interrogatories: 8.5-Staff-31; 8.5-VECC-46 and 47

Included with this settlement proposal is the response to 8.5-VECC-46, in live Microsoft Excel format, which represents the agreed-upon RTSR Adjustment Work Form.

Supporting parties: CND, EP, SEC and VECC.

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?

No Settlement: Because the Parties are not in agreement on several matters which are an input into the derivation of proposed rates (including operating expenses, return on capital, and interest revenues), the Parties also do not agree on the proposed Tariff of Rates and Charges.

9. Accounting

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

Partial Settlement: For the purposes of settlement of the issues in this proceeding, and subject to the treatment of removal costs within account 1576, the Parties agree that the proposed deferral accounts, both new and existing, account balances, allocation methodology, disposition periods and related rate riders are appropriate, subject to the following:

1. In response to interrogatory 9.1-Staff-32, the Applicant has withdrawn its request for disposal of the balance in account 1508 (Other).

2. The Applicant will not seek disposal of account 1508 (IFRS transition costs) in the test year in favour of waiting until all such costs are known (see also 9.1-Staff-32).

3. The Parties accept the [$107,000] adjustment to account 1592 as noted in 9.1-Staff-33, plus carrying charges, resulting in a total tax credit of [$335,136].

4. Given that account 2425 was intended to be an asymmetrical variance account in favour of ratepayers in the event of under spending on the CIS system by the Applicant, and given that the Applicant overspent on the CIS system (first on the SAP system which was largely written off, and subsequently on the Harris system which was implemented) the Parties agree that the total amount that should be recorded in account 2425 for disposition in favour of ratepayers is $0 as opposed to the original claim of $361k.

   The following table summarizes the total amount of the expenditures on the CIS system in excess of the 2010 Board Approved amount.

SAP hardware and software expenditures (abandoned)	$1,195,531
Harris/NorthStar CIS/Billing System expenditures (in use)	$1,016,038
Total expenditures on CIS	$2,211,569
Capital costs reflected in CND's 2010 Distribution Rates	$1,850,000
Expenditures in excess of 2010 Approved Amount	$361,569

5. In response to IR 9.1-Staff-38, CND updated the balance in account 1568 – Lost Revenue Adjustment Mechanism, to reflect 2012 results as provided by the OPA. The Parties agree to the updated account balance of $180,825. LRAM adjustments by class are indicated in the Table below.

2014 LRAMVA Allocation per Customer Class

	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Large User	Direct Market Participant	Street Lights	Unmetered Loads	Total
kWh	11,108,643	4,314,499	12,006,086	6,095,436	5,684,186	1,259,827	263,370	47,953	40,780,000
kW			38,780	14,499	11,778	2,174	707		67,938

6. The Parties agree to the Applicant’s proposal related to account 1555 stranded meters as reflecting appropriately determined and allocated costs. Please refer to Appendix H to this document for the agreed upon Stranded Meter Rate Riders.

With the exception of account 1576, the following table summarizes the balances in the deferral/variance accounts agreed to by the Parties:

Deferral/Variance Account Balances

	Total Claim by Account Number	Original as Filed	Adjustments Through Interrogatories	Adjustments Through Settlement	Agreed to at Settlement	Interrogatory Reference
Account Number	Description	Amount	Amount	Amount	Amount	
Group 1 Accounts						
1550	Low Voltage	$82,597	$0	$0	$82,597	
1580	Wholesale Market Service	($1,876,573)	$0	$0	($1,876,573)	
1584	Transmission Network	$134,181	$0	$0	$134,181	
1586	Transmission Connections	$240,823	$0	$0	$240,823	
1588	Power	($738,875)	$0	$0	($738,875)	
1595	Disposal and Recovery (2010)	$180,963	$0	$0	$180,963	
1595	Disposal and Recovery (2011)	$3,774	$0	$0	$3,774	
Group 1 Excluding GA		($1,973,110)	$0	$0	($1,973,110)	
Group 2 Accounts						
1508	Other	$41,723	($41,723)	$0	$0	(IR 9.1-Staff-32)
1508	IFRS Transiation Costs	$17,361	$0	($17,361)	$0	(Settlement)
1508	Late Payment Penalty	($16,823)	$0	$0	($16,823)	
1518	Retail Costs	$43,833	$0	$0	$43,833	
1534	Smart Grid Capital	$35,886	$0	$0	$35,886	(IR 9.1-Staff-35)
1535	Smart Grid OM&A	$12,504	$0	$0	$12,504	(IR 9.1-Staff-36)
1548	Service Transaction Requests	$1,369	$0	$0	$1,369	
2425	Other	$404,160	$0	($404,160)	$0	(IR 9.1-Staff-34, 9.1-Energy Probe-43)
Group 2 Subtotal		$540,013	($41,723)	($421,521)	$76,769	
Other Accounts						
1592	PST vs. HST	($215,789)	$0	($119,347)	($335,136)	(IR 9.1-Staff-33)
1568	Lost Revenue Adjustment	$108,262	$72,563	$0	$180,825	(IR 9.1-Staff-38)
Other Accounts Subtotal		($107,527)	$72,563	($119,347)	($154,311)	
Total of Accounts		($1,540,624)	$30,840	($540,868)	($2,050,652)	
1589	Global Adjustment	($2,864,021)	$0	$0	($2,864,021)	
Subtotal		($4,404,645)	$30,840	($540,868)	($4,914,673)	
1555	Stranded Meters	$2,446,645	$0	$0	$2,446,645	(IR 9.1-Staff-37)
1576	CGAAP vs. IFRS	($3,451,198)	$0	$0	($3,451,198)	(IR 9.2-Staff-39 and 40) NOT SETTLED
Total of All Accounts		($5,409,198)	$30,840	($540,868)	($5,919,226)	

Please refer to Appendix I for the Rate Riders (as calculated in the EDVAR Deferral/Variance Workform for 2014 Filers, which has been updated to reflect the agreed upon load forecast figures, and included as a live excel worksheet).

Evidence: Exhibit 9

Interrogatories: 9.1-Staff-32 to 38.

Supporting parties: CND, EP, SEC and VECC.

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?

Partial Settlement: For the purposes of partial settlement of the issues in this proceeding, the Parties agree that, with the exception of the treatment of removal costs, the impacts of any changes in accounting standards, policies, estimates and adjustments have been properly identified, and the treatment of each of these impacts is appropriate.

The Parties are not in agreement on the proper accounting treatment of removal costs in the test year.

Evidence: Exhibit 1/Tab 8/Schedule 6; Exhibit 4/Tab 2/Schedule 1/Page 15; Exhibit 4/Appendix 4-5 – Appendix 2-DB (Overhead Expenses); Exhibit 9/Appendix 9-3 – Appendix 2-ED (Account 1576 – Accounting Changes under CGAAP).

Interrogatories: 9.2-Staff-39 and 40

Appendix A – Updated Net Book Values

Updated Net Book Values				
	2014 As Per Application	Adjust for 2013 Actual Capital	Adjust for 2014 Capital ($2.6 M)	2014 Amended
Gross Fixed Assets	222,575,592	(1,050,484)	(2,600,000)	218,925,108
Accumulated Depreciation	105,758,033	(184,432)	(30,614)	105,542,987
Net Book Value	116,817,559	(866,052)	(2,569,386)	113,382,121
Average Net Book Value	110,487,806			108,337,061

Detailed calculation support:

	2013	2014
Capital additions per application	16,082,753	
Actual Net Capital additions	15,032,270	
Difference	1,050,483	
Capital additions per application		17,649,383
Capital additions per Settlement		15,049,383
Adjustment per Settlement		2,600,000
Depreciation per application	4,181,269	
Actual depreciation	3,996,837	
Difference	184,432	
Depreciation per application		4,989,877
Depreciation applied to revised capital		4,959,263
Difference		30,614

Note: Subject to any adjustments arising from the resolution of accounting for removal costs.

Appendix B 2014 Fixed Asset Continuity Schedule

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**
12	1611	Computer Software (Formally known as Account 1925)				$ -				$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)				$ -				$ -	$ -
N/A	1805	Land	$ 252,923	$ -	$ -	$ 252,923	$ -	$ -	$ -	$ -	$ 252,923
47	1808	Buildings	$ 1,190,197	$ -	$ -	$ 1,190,197	$ 284,772	$ 21,351	$ -	$ 306,123	$ 884,074
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 10,053,774	$ -	$ -	$ 10,053,774	$ 3,117,519	$ 365,445	$ -	$ 3,482,964	$ 6,570,810
47	1820	Distribution Station Equipment <50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 31,526,865	$ 3,811,674	$ -	$ 35,338,539	$ 14,720,334	$ 502,914	$ -	$ 15,223,248	$ 20,115,291
47	1835	Overhead Conductors & Devices	$ 37,630,438	$ 4,438,705	$ -	$ 42,069,143	$ 17,302,840	$ 684,064	$ -	$ 17,986,904	$ 24,082,239
47	1840	Underground Conduit	$ 27,728,747	$ 1,538,037	$ -	$ 29,266,784	$ 13,324,663	$ 210,456	$ -	$ 13,535,119	$ 15,731,665
47	1845	Underground Conductors & Devices	$ 40,244,002	$ 2,168,077	$ -	$ 42,412,079	$ 19,190,611	$ 528,980	$ -	$ 19,719,591	$ 22,692,488
47	1850	Line Transformers	$ 46,238,994	$ 1,682,299	$ -	$ 47,921,293	$ 22,915,044	$ 647,510	$ -	$ 23,562,553	$ 24,358,740
47	1855	Services (Overhead & Underground)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1860	Meters	$ 10,164,609	$ 966,643	$ -	$ 11,131,252	$ 2,434,033	$ 717,254	$ -	$ 3,151,287	$ 7,979,965
47	1860	Meters (Smart Meters)				$ -				$ -	$ -
N/A	1905	Land	$ 213,797	$ -	$ -	$ 213,797	$ -	$ -	$ -	$ -	$ 213,797
47	1908	Buildings & Fixtures	$ 5,575,328	$ 55,000	$ -	$ 5,630,328	$ 3,688,406	$ 155,304	$ -	$ 3,843,710	$ 1,786,618
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 772,183	$ 80,400	$ -	$ 852,583	$ 527,747	$ 40,396	$ -	$ 568,143	$ 284,440
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 2,515,576	$ 751,500	$ -	$ 3,267,076	$ 1,894,382	$ 514,213	$ -	$ 2,408,595	$ 858,481
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
12	1925	Computer Software	$ 3,524,730	$ 1,334,048	$ -	$ 4,858,778	$ 1,999,040	$ 677,095	$ -	$ 2,676,135	$ 2,182,643
10	1930	Transportation Equipment	$ 4,361,424	$ 520,000	$ -	$ 4,881,424	$ 2,715,516	$ 233,631	$ -	$ 2,949,147	$ 1,932,277
8	1935	Stores Equipment	$ 93,729	$ -	$ -	$ 93,729	$ 93,729	$ -	$ -	$ 93,729	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 1,151,630	$ 109,000	$ -	$ 1,260,630	$ 734,420	$ 85,910	$ -	$ 820,330	$ 440,300
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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	$ 714,214	$ -	$ -	$ 714,214	$ 714,214	$ -	$ -	$ 714,214	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ (20,139,307)	$ (2,406,000)	$ -	$ (22,545,307)	$ (5,135,420)	$ (425,260)	$ -	$ (5,560,680)	$ (16,984,627)
	2005	Property under Capital Lease	$ 61,873	$ -	$ -	$ 61,873	$ 61,873	$ -	$ -	$ 61,873	$ (0)
		Sub-Total	**$ 203,875,726**	**$ 15,049,383**	**$ -**	**$ 218,925,109**	**$ 100,583,723**	**$ 4,959,263**	**$ -**	**$ 105,542,986**	**$ 113,382,123**
WIP		Work in Process	$ 946,429	$ -	$ -	$ 946,429	$ -	$ -	$ -	$ -	$ 946,429
	2070	Other Utility Plant - assets not in use	$ 145,798	$ -	$ -	$ 145,798	$ -	$ -	$ -	$ -	$ 145,798
		Sub-Total	**$ 204,967,953**	**$ 15,049,383**	**$ -**	**$ 220,017,336**	**$ 100,583,723**	**$ 4,959,263**	**$ -**	**$ 105,542,986**	**$ 114,474,350**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 204,967,953**	**$ 15,049,383**	**$ -**	**$ 220,017,336**	**$ 100,583,723**	**$ 4,959,263**	**$ -**	**$ 105,542,986**	**$ 114,474,350**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ 233,631
Stores Equipment	$ -
Add: Removal costs	$ 806,208
Net Depreciation	$5,531,840

Note: Subject to any adjustments arising from the resolution of accounting for removal costs.

Appendix C Capital Expenditure Summary

Appendix 2-AB Capital Expenditure Summary 2009 through 2018
Capital Expenditure Summary

	Historical (Actual)				Forecast (Planned)						
	Test-5 2009	Test-4 2010	Test-3 2011	Test-2 2012	Test -1 2013	Test -1 2013	Test 2014	Test +1 2015	Test +2 2016	Test +3 2017	Test +4 2018
	Actual	Actual	Actual	Actual	Forecast	Actual	Plan	Plan	Plan	Plan	Plan
Category	$'000	$'000	$'000	$'000	$'000	$'000	$'000	$'000	$'000	$'000	$'000
System Access	3,966	4,152	3,140	3,032	8,411	7,654	8,123	6,857	4,143	4,020	3,496
System Renewal	5,240	6,262	3,999	2,886	7,089	4,413	5,229	9,058	4,033	3,766	3,554
System Service	54	425	716	835	760	790	287	744	629	342	16,842
General Plant	1,257	1,436	2,187	10,108	2,864	2,355	3,817	2,169	2,135	2,270	2,060
Capital Contributions	(2,326)	(1,804)	(1,342)	(368)	(3,041)	(2,880)	(2,406)	(3,800)	(2,100)	(2,000)	(1,800)
Change in WIP	(118)	(576)	(338)	(3,011)		2,856					
Total	8,073	9,895	8,362	13,482	16,083	15,188	15,050	15,028	8,840	8,398	24,152
System O&M	3,376	3,448	3,769	5,096	4,064	3,987	4,537	5,240	5,036	4,929	4,820

Note: 2013 Actuals subject to Audit.

Note: Subject to any adjustments arising from the resolution of accounting for removal costs.

Appendix D Other Revenue

Other Distribution Revenues								
USoA Account	Account Description	2010 Board Approved	2010 Actual	2011 Actual	2012 Actual	2013 Subject to Audit	2014 Test	
4080	SSS Administration Charge	$ -	$ 129,161	$ 137,093	$ 143,062	$ 145,542	$ 146,868	
4082	Retail Services Revenue	$ 76,400	$ 72,083	$ 59,378	$ 45,022	$ 38,220	$ 36,000	
4084	Service Transaction Request (STR) Revenue	$ -	$ 2,729	$ 1,589	$ 1,325	$ 1,072	$ 960	
4210	Rent from Electric Property	$ 202,080	$ 216,336	$ 219,051	$ 235,066	$ 228,939	$ 211,684	
4225	Late Payment Charges	$ 349,055	$ 341,691	$ 170,595	$ 125,188	$ 130,917	$ 137,500	
4235	Specific Services Charges	$ 540,140	$ 573,349	$ 537,171	$ 543,360	$ 522,434	$ 554,855	
4325	Revenues from Merchandise, Jobbing, etc.	$ -	$ 140,158	$ 132,975	$ 137,381	$ 139,977	$ 145,798	
4355	Gain on Disposition of Utility and Other Property	$ -	$ -	$ 34,623	$ 47,166	$ 3,141	$ 23,000	
4360	Loss on Disposition of Utility and Other Property	$ -	$ (367,825)	$ (292)	$ (312)	$ -	$ -	
4375	Revenues from Non-Utility Operations	$ 322,735	$ 1,342,217	$ 1,167,880	$ 518,753	$ 498,819	$ 564,581	
4390	Miscellaneous Non-Operating Income	$ -	$ 146,700	$ 130,196	$ 88,971	$ 191,148	$ 139,400	
4405	Interest and Dividend Income	$ -	$ 399,141	$ 412,032	$ 493,844	$ 216,143	$ 52,712	Not Settled
	TOTAL	$ 1,490,410	$ 2,995,740	$ 3,002,291	$ 2,378,825	$2,116,352	$ 2,013,358	
	Less:							
4330	Costs & Expenses re: 4325	$ -	$ (106,697)	$ (110,092)	$ (113,241)	$ (118,292)	$ (121,798)	
4380	Expense re: 4375	$ -	$ (376,745)	$ (351,520)	$ (506,973)	$ (487,539)	$ (538,181)	
	Total Revenue Offsets	**$ 1,490,410**	**$ 2,512,298**	**$ 2,540,679**	**$ 1,758,612**	**$1,510,521**	**$ 1,353,379**	

Appendix E Settled Load Forecast.

Cambridge and North Dumfries Hydro inc. Settlement Table - Load Forecast 2014

Rate Class	Cost of Service as Filed	Adjustments	Settlement Submission
Residential			
Customers	48,091	0	48,091
kWh	395,264,057	5,382,031	400,646,088
General Service < 50 kW			
Customers	4,740	0	4,740
kWh	153,517,084	2,090,333	155,607,417
General Service > 50 to 999 kW			
Customers	773	0	773
kWh	431,657,534	2,890,555	434,548,089
kW	1,226,670	176,920	1,403,590
General Service > 1000 to 4999 kW			
Customers	27	0	27
kWh	221,335,611	34,196	221,369,807
kW	526,492	81	526,573
Large User			
Customers	2	0	2
kWh	208,256,974	(1,184,625)	207,072,349
kW	431,512	(2,456)	429,056
Direct Market Participant			
Customers	1	0	1
kWh	46,157,494	(262,557)	45,894,937
kW	79,664	(453)	79,211
Streetlights			
Connections	12,997	0	12,997
kWh	9,649,328	(54,889)	9,594,439
kW	25,898	(147)	25,751
Unmetered Loads			
Connections	482	0	482
kWh	1,756,889	(9,994)	1,746,895
Embedded Distributor			
Customers	2	0	2
kWh	43,430,869	0	43,430,869
kW	90,564	12,280	102,844
Total			
Customer/Connections	67,115	0	67,115
kWh	1,511,025,840	8,885,051	1,519,910,891
kW	2,380,800	186,226	2,567,026

CDM Adjustments to Load Forecast

Rate Class	Billed Load Forecast before CDM Adjustment (kWh)	Billed Load Forecast after CDM Adjustment (kWh)	CDM Adjustment (kWh)
Residential	404,988,211	400,646,088	(4,342,123)
General Service < 50 kW	157,293,860	155,607,417	(1,686,442)
General Service > 50 to 999 kW	439,241,003	434,548,089	(4,692,914)
General Service > 1000 to 4999 kW	223,752,378	221,369,807	(2,382,571)
Large User	209,294,172	207,072,349	(2,221,823)
Direct Market Participant	46,387,375	45,894,937	(492,438)
Streetlights	9,697,385	9,594,439	(102,946)
Unmetered Loads	1,765,639	1,746,895	(18,744)
Embedded Distributor	43,430,869	43,430,869	0
	1,535,850,891	**1,519,910,891**	**(15,940,000)**

4 Year (2011-2014) kWh Target:
73,660,000

	2011	2012	2013	2014	Total
2011 CDM Programs	18.3%	17.5%	17.5%	17.4%	70.7%
2012 CDM Programs		10.7%	10.7%	10.6%	32.0%
2013 CDM Programs			6.4%	5.3%	11.7%
2014 CDM Programs				22.0%	22.0%
Total in Year	**18.3%**	**28.3%**	**34.6%**	**55.4%**	**136.4%**
		kWh			
2011 CDM Programs	13,450,000	12,900,000	12,900,000	12,820,000	52,070,000
2012 CDM Programs		7,910,000	7,850,000	7,810,000	23,570,000
2013 CDM Programs			4,708,000	3,920,000	8,628,000
2014 CDM Programs				16,230,000	16,230,000
Total in Year	**13,450,000**	**20,810,000**	**25,458,000**	**40,780,000**	**100,498,000**

2014 LRAMVA Allocation per Customer Class

	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Large User	Direct Market Participant	Street Lights	Unmetered Loads	Total
kWh	11,108,643	4,314,499	12,006,086	6,095,436	5,684,186	1,259,827	263,370	47,953	40,780,000
kW			38,780	14,499	11,778	2,174	707		67,938

Appendix F Settled and Partially Settled Fixed and Variable Splits

FIXED CHARGE ANALYSIS

Customer Class	2013 Rates from OEB Approved Tariff	Current Fixed Split	Current Variable Split	Total	2014 Fixed Rate Based on Current F/V Revenue Proportions	Proposed Fixed Split	Proposed Variable Split	Total	Fixed Charge for 2014 as Proposed	Ceiling Fixed Charges from Cost Allocation Study	Floor Fixed Charges from Cost Allocation Study	Proposed Fixed Charges at Settlement	
Residential	$10.09	47%	53%	100%	$11.58	55%	45%	100%	$13.32	$16.55	$4.35	$11.58	
GS <50 kW	$11.92	26%	74%	100%	$13.78	35%	65%	100%	$18.48	$25.03	$9.49	$13.78	
GS 50-999 kW	$109.35	19%	81%	100%	$126.44	19%	81%	100%	$126.44	$96.99	$48.84	$126.44	Not Settled
GS1000-4999 kW	$908.75	18%	82%	100%	$1,050.20	18%	82%	100%	$1,050.20	$317.41	$47.52	$1,050.20	
Large Use	$7,785.09	20%	80%	100%	$8,998.17	20%	80%	100%	$8,998.17	$883.34	$556.68	$8,998.17	
Street Lighting	$2.04	49%	51%	100%	$2.75	49%	51%	100%	$2.75	$8.55	$0.13	$2.75	
USL	$7.07	61%	39%	100%	$6.39	61%	39%	100%	$6.39	$5.43	$0.11	$6.39	
Embedded Distributors	n/a	0%	100%	100%	n/a	0%	100%	100%	n/a	n/a	n/a	n/a	

Appendix G Agreed Upon Loss Adjustment Factors.

Total Utility Loss Adjustment Factor	
Total Loss Factor	
Total Loss Factor - Secondary Metered Customer < 5000 kW	1.0335
Total Loss Factor - Secondary Metered Customer > 5000 kW	1.0145
Total Loss Factor - Primary Metered Customer < 5000 kW	1.0235
Total Loss Factor - Primary Metered Customer > 5000 kW	1.0045

Appendix H Agreed Upon Stranded Meter Rates

Customer Class Rate Rider			
Net Stranded Meter Costs	$2,446,645		
	Residential	GS <50kW	Total
Number of customers - 2014 Forecast	48,091	4,740	52,831
Allocation of Meter Capital Costs as per 2010 Cost Allocation Model I7.1	49.37%	15%	64.37%
Allocation of Residential and GS<50 only	76.70%	23.30%	100.00%
Allocation of Net Stranded Meter Costs	$1,876,577	$570,068	$2,446,645
Stranded Meter Rate Rider per Customer Class (SMRR)	$3.25	$10.02	
Annual Cost	$39.02	$120.27	

Appendix I Rate Riders

Rate Rider Calculation for Deferral / Variance Accounts Balances (excluding Global Adj.)

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts	
Residential	kWh	400,646,088	-$ 614,826	- 0.0015	$/kWh
General Service < 50kW	kWh	155,607,417	-$ 206,997	- 0.0013	$/kWh
General Service > 50kW	kW	1,403,590	-$ 512,559	- 0.3652	$/kW
General Service 1000 to 4999 kW	kW	526,573	-$ 298,387	- 0.5667	$/kW
Large Users	kW	508,268	-$ 339,257	- 0.6675	$/kW
Street Lighting	kW	25,751	-$ 15,013	- 0.5830	$/kW
Unmetered Scattered Load	kWh	1,746,895	-$ 853	- 0.0005	$/kWh
Embedded Distributor	kW	102,844	-$ 62,756	- 0.6102	$/kW
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
Total			**-$ 2,050,648**		

Rate Rider Calculation for RSVA - Power - Global Adjustment

Rate Class (Enter Rate Classes in cells below)	Units	Non-RPP kW / kWh / # of Customers	Balance of RSVA - Power - Global Adjustment	Rate Rider for RSVA - Power - Global Adjustment	
Residential	kWh	31,090,136	-$ 111,824	- 0.0036	$/kWh
General Service < 50kW	kWh	22,469,711	-$ 80,819	- 0.0036	$/kWh
General Service > 50kW	kW	943,353	-$ 1,050,475	- 1.1136	$/kW
General Service 1000 to 4999 kW	kW	526,573	-$ 796,219	- 1.5121	$/kW
Large Users	kW	416,055	-$ 744,794	- 1.7901	$/kW
Street Lighting	kW	25,751	-$ 34,509	- 1.3401	$/kW
Unmetered Scattered Load	kWh	3,494	-$ 13	- 0.0036	$/kWh
Embedded Distributor	kW	29,869	-$ 45,368	- 1.5189	$/kW
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
Total			**-$ 2,864,021**		

Revenue Requirement Workform

Version 4.00

Utility Name	Cambridge and North Dumfries Hydro
Service Territory	
Assigned EB Number	EB-2013-0116
Name and Title	Grant Brooker, Manager, Regulatory Affairs
Phone Number	519.621.8405 Ext 2340
Email Address	gbrooker@camhydro.com

Revenue Requirement Workform

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)	$213,750,900		($2,350,483)	$ 211,400,417			$211,400,417	
	Accumulated Depreciation (average)	($103,263,094)	(5)	$199,738.66	($103,063,355)			($103,063,355)	
	Allowance for Working Capital:								
	Controllable Expenses	$15,958,975		($1,025,239)	$ 14,933,736			$14,933,736	
	Cost of Power	$153,046,408		$4,854,845	$ 157,901,253			$157,901,253	
	Working Capital Rate (%)	13.00%	(9)		13.00%	(9)		13.00%	(9)
2	**Utility Income**								
	Operating Revenues:								
	Distribution Revenue at Current Rates	$24,193,543		$135,556	$24,329,099				
	Distribution Revenue at Proposed Rates	$27,966,045		($57,166)	$27,908,879				
	Other Revenue:								
	Specific Service Charges	$554,855		$0	$554,855				
	Late Payment Charges	$137,500		$0	$137,500				
	Other Distribution Revenue	$607,024		$54,000	$661,024				
	Other Income and Deductions								
	Total Revenue Offsets	$1,299,379	(7)	$54,000	$1,353,379				
	Operating Expenses:								
	OM+A Expenses	$15,803,311		($866,408)	$ 14,936,903			$14,936,903	
	Depreciation/Amortization	$4,756,246		$775,594	$ 5,531,840			$5,531,840	
	Property taxes	$155,664			$ 155,664			$155,664	
	Other expenses								
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($4,641,026)	(3)		($4,430,741)				
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$ -			$ -				
	Income taxes (grossed up)	$ -			$ -				
	Federal tax (%)	0.00%			0.00%				
	Provincial tax (%)	0.00%			0.00%				
	Income Tax Credits								
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%			56.0%				
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		4.0%	(8)			(8)
	Common Equity Capitalization Ratio (%)	40.0%			40.0%				
	Prefered Shares Capitalization Ratio (%)	0.0%			0.0%				
		100.0%			100.0%				
	Cost of Capital								
	Long-term debt Cost Rate (%)	4.96%			4.96%				
	Short-term debt Cost Rate (%)	2.07%			2.11%				
	Common Equity Cost Rate (%)	8.98%			9.36%				
	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.

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)	$213,750,900	($2,350,483)	$211,400,417	$ -	$211,400,417
2	Accumulated Depreciation (average)	(3)	($103,263,094)	$199,739	($103,063,355)	$ -	($103,063,355)
3	Net Fixed Assets (average)	(3)	$110,487,806	($2,150,744)	$108,337,062	$ -	$108,337,062
4	Allowance for Working Capital	(1)	$21,970,700	$497,849	$22,468,549	$ -	$22,468,549
5	**Total Rate Base**		$132,458,506	($1,652,896)	$130,805,610	$ -	$130,805,610

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
6	Controllable Expenses		$15,958,975	($1,025,239)	$14,933,736	$ -	$14,933,736
7	Cost of Power		$153,046,408	$4,854,845	$157,901,253	$ -	$157,901,253
8	Working Capital Base		$169,005,383	$3,829,606	$172,834,989	$ -	$172,834,989
9	Working Capital Rate %	(2)	13.00%	0.00%	13.00%	0.00%	13.00%
10	Working Capital Allowance		$21,970,700	$497,849	$22,468,549	$ -	$22,468,549

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)		$27,966,045	($57,166)	$27,908,879	$ -	$27,908,879
2	Other Revenue	(1)	$1,299,379	$54,000	$1,353,379	$ -	$1,353,379
3	Total Operating Revenues		$29,265,424	($3,166)	$29,262,258	$ -	$29,262,258
	Operating Expenses:						
4	OM+A Expenses		$15,803,311	($866,408)	$14,936,903	$ -	$14,936,903
5	Depreciation/Amortization		$4,756,246	$775,594	$5,531,840	$ -	$5,531,840
6	Property taxes		$155,664	$ -	$155,664	$ -	$155,664
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$20,715,221	($90,814)	$20,624,407	$ -	$20,624,407
10	Deemed Interest Expense		$3,792,294	($51,804)	$3,740,490	$4,481	$3,744,971
11	Total Expenses (lines 9 to 10)		$24,507,515	($142,618)	$24,364,897	$4,481	$24,369,378
12	**Utility income before income taxes**		$4,757,909	$139,452	$4,897,361	($4,481)	$4,892,880
13	Income taxes (grossed-up)		$ -	$ -	$ -	$ -	$ -
14	**Utility net income**		$4,757,909	$139,452	$4,897,361	($4,481)	$4,892,880

Notes

Other Revenues / Revenue Offsets

Note	Particulars	Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
(1)	Specific Service Charges	$554,855	$ -	$554,855		$554,855
	Late Payment Charges	$137,500	$ -	$137,500		$137,500
	Other Distribution Revenue	$607,024	$54,000	$661,024		$661,024
	Other Income and Deductions	$ -		$ -		$ -
	Total Revenue Offsets	$1,299,379	$54,000	$1,353,379	$ -	$1,353,379

Revenue Requirement Workform

Taxes/PILs

Line No.	Particulars	Application	Settlement Agreement	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$4,757,910	$4,897,362	$4,698,538
2	Adjustments required to arrive at taxable utility income	($4,641,026)	($4,430,741)	($4,641,026)
3	Taxable income	$116,884	$466,622	$57,512
	Calculation of Utility income Taxes			
4	Income taxes	$ -	$ -	$ -
6	Total taxes	$ -	$ -	$ -
7	Gross-up of Income Taxes	$ -	$ -	$ -
8	Grossed-up Income Taxes	$ -	$ -	$ -
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$ -	$ -	$ -
10	Other tax Credits	$ -	$ -	$ -
	Tax Rates			
11	Federal tax (%)	0.00%	0.00%	0.00%
12	Provincial tax (%)	0.00%	0.00%	0.00%
13	Total tax rate (%)	0.00%	0.00%	0.00%

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%	$74,176,763	4.96%	$3,682,618
2	Short-term Debt	4.00%	$5,298,340	2.07%	$109,676
3	**Total Debt**	60.00%	$79,475,103	4.77%	$3,792,294
	Equity				
4	Common Equity	40.00%	$52,983,402	8.98%	$4,757,910
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$52,983,402	8.98%	$4,757,910
7	**Total**	100.00%	$132,458,506	6.46%	$8,550,203
		Settlement Agreement			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$73,251,142	4.96%	$3,630,090
2	Short-term Debt	4.00%	$5,232,224	2.11%	$110,400
3	**Total Debt**	60.00%	$78,483,366	4.77%	$3,740,490
	Equity				
4	Common Equity	40.00%	$52,322,244	9.36%	$4,897,362
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$52,322,244	9.36%	$4,897,362
7	**Total**	100.00%	$130,805,610	6.60%	$8,637,852
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$73,251,142	4.96%	$3,636,664
9	Short-term Debt	4.00%	$5,232,224	2.07%	$108,307
10	**Total Debt**	60.00%	$78,483,366	4.77%	$3,744,971
	Equity				
11	Common Equity	40.00%	$52,322,244	8.98%	$4,698,538
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$52,322,244	8.98%	$4,698,538
14	**Total**	100.00%	$130,805,610	6.46%	$8,443,509

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		$3,772,502		$3,579,781		$3,385,438
2	Distribution Revenue	$24,193,543	$24,193,543	$24,329,099	$24,329,098	$24,329,099	$24,523,441
3	Other Operating Revenue Offsets - net	$1,299,379	$1,299,379	$1,353,379	$1,353,379	$1,353,379	$1,353,379
4	**Total Revenue**	$25,492,922	$29,265,424	$25,682,478	$29,262,258	$25,682,478	$29,262,258
5	Operating Expenses	$20,715,221	$20,715,221	$20,624,407	$20,624,407	$20,624,407	$20,624,407
6	Deemed Interest Expense	$3,792,294	$3,792,294	$3,740,490	$3,740,490	$3,744,971	$3,744,971
8	**Total Cost and Expenses**	$24,507,515	$24,507,515	$24,364,897	$24,364,897	$24,369,378	$24,369,378
9	**Utility Income Before Income Taxes**	$985,407	$4,757,909	$1,317,581	$4,897,361	$1,313,100	$4,892,880
10	Tax Adjustments to Accounting Income per 2013 PILs model	($4,641,026)	($4,641,026)	($4,430,741)	($4,430,741)	($4,430,741)	($4,430,741)
11	**Taxable Income**	($3,655,619)	$116,883	($3,113,159)	$466,621	($3,117,641)	$462,139
12	Income Tax Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
13	**Income Tax on Taxable Income**	$ -	$ -	$ -	$ -	$ -	$ -
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
15	**Utility Net Income**	$985,407	$4,757,909	$1,317,581	$4,897,361	$1,313,100	$4,892,880
16	**Utility Rate Base**	$132,458,506	$132,458,506	$130,805,610	$130,805,610	$130,805,610	$130,805,610
17	Deemed Equity Portion of Rate Base	$52,983,402	$52,983,402	$52,322,244	$52,322,244	$52,322,244	$52,322,244
18	Income/(Equity Portion of Rate Base)	1.86%	8.98%	2.52%	9.36%	2.51%	9.35%
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	-7.12%	0.00%	-6.84%	0.00%	-6.47%	0.37%
21	Indicated Rate of Return	3.61%	6.46%	3.87%	6.60%	3.87%	6.60%
22	Requested Rate of Return on Rate Base	6.46%	6.46%	6.60%	6.60%	6.46%	6.46%
23	Deficiency/Sufficiency in Rate of Return	-2.85%	0.00%	-2.74%	0.00%	-2.59%	0.15%
24	Target Return on Equity	$4,757,910	$4,757,910	$4,897,362	$4,897,362	$4,698,538	$4,698,538
25	Revenue Deficiency/(Sufficiency)	$3,772,502	($0)	$3,579,781	($1)	$3,385,438	$194,342
26	**Gross Revenue Deficiency/(Sufficiency)**	$3,772,502 **(1)**		$3,579,781 **(1)**		$3,385,438 **(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	$15,803,311		$14,936,903		$14,936,903	
2	Amortization/Depreciation	$4,756,246		$5,531,840		$5,531,840	
3	Property Taxes	$155,664		$155,664		$155,664	
5	Income Taxes (Grossed up)	$ -		$ -		$ -	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$3,792,294		$3,740,490		$3,744,971	
	Return on Deemed Equity	$4,757,910		$4,897,362		$4,698,538	
8	**Service Revenue Requirement (before Revenues)**	$29,265,424		$29,262,259		$29,067,916	
9	Revenue Offsets	$1,299,379		$1,353,379		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$27,966,045		$27,908,880		$29,067,916	
11	Distribution revenue	$27,966,045		$27,908,879		$27,908,879	
12	Other revenue	$1,299,379		$1,353,379		$1,353,379	
13	**Total revenue**	$29,265,424		$29,262,258		$29,262,258	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($0)	(1)	($1)	(1)	$194,342	(1)

Notes

(1) Line 11 - Line 8